Harvest Energy Trust

2005 ANNUAL REVIEW

Securing Our Future

WHY INVESTORS

HARVEST ENERGY TRUST is a Calgary-based oil and natural gas royalty trust that has experienced significant growth and value appreciation. With our balanced asset base, superior 'hands-on' operational expertise, extensive land holdings, depth of development opportunities and access to varied sources of low-cost capital, we are well positioned to continue generating positive returns for Harvest unitholders.

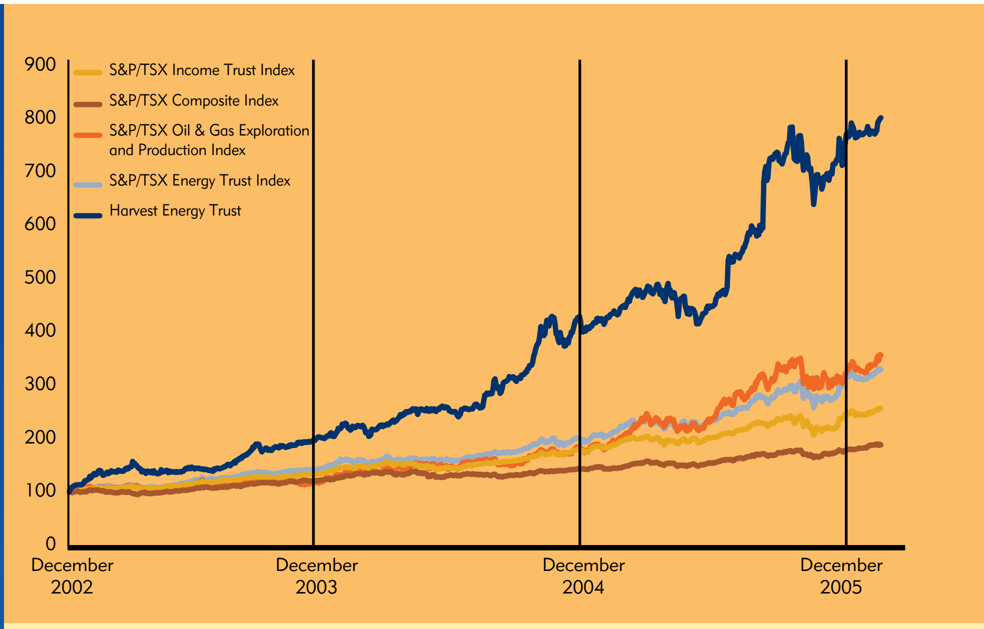
OUR TRADING SYMBOLS ARE: TSX – HTE.UN AND NYSE – HTE.

PERFORMANCE TRACK RECORD

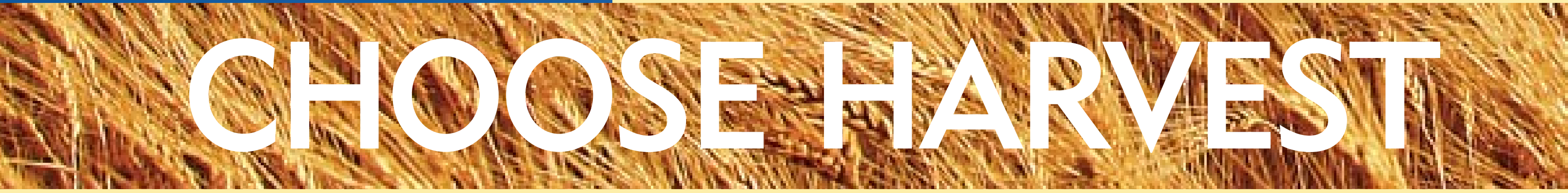
Over the past three years, we have increased daily production volumes by 230%, cash flow per unit by 80%, distributions by 75%, and delivered more distributions per unit than our initial public offering price of C$8.00 per unit.

STRATEGY OF SUSTAINABILITY

Future internal development projects include over 700 net wells and more than 740,000 net acres of undeveloped land situated on over 1.8 billion barrels of original resource-in-place. Financial flexibility is afforded by our new C$900 million credit facility with significant undrawn capacity, access to U.S. and Canadian debt and equity markets, and a responsible payout ratio.



HARVEST TOTAL RETURN SINCE INCEPTION



CHOOSE HARVEST

BALANCED PRODUCTION BASE

Current production is weighted 50% to light and medium oil, 25% to natural gas and 25% to heavy oil / oil sands production. Our year over year production per unit has remained stable, with 2005 production per debt adjusted trust unit increasing 1.5% from 594 BOE/d per million trust units in 2004 to 603 BOE/d per million trust units in 2005.

RESERVES GROWTH

Our proved plus probable reserves per unit increased 11% in 2005 on a debt adjusted basis, a strong indicator of value generation. Our Reserve Life Index has increased to 9.4 following the Viking merger.

POSITIVE UNITHOLDER RETURNS

Harvest has generated a total return to Unitholders of 661% since inception, and in 2005 led the performance of the conventional energy royalty trusts with a total return to Unitholders of 76%.

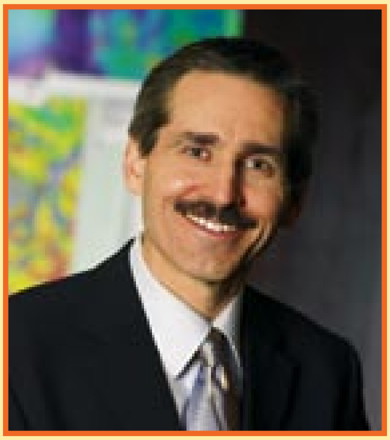
HIGHLIGHTS

	2005	2004	2003
FINANCIAL			
Cash Flow ($M)	**309,843**	123,710	46,492
Cash Flow per Unit ($/Trust Unit, basic)	**$ 6.66**	$ 4.94	$ 3.69
Distributions declared ($M)	**153,494**	64,563	30,685
Distributions declared per Unit ($/Trust Unit, basic)[1]	**$ 3.20**	$ 2.40	$ 2.40
Payout Ratio (%)	**50%**	52%	66%
Total Assets	**1,308,481**	1,050,483	256,440
Debt			
Senior Debt	**290,750**	300,500	–
Equity Bridge Notes	**–**	–	25,000
Bank Debt	**13,869**	75,519	63,349
Convertible Debentures	**47,036**	25,859	–
Working Capital deficit/(surplus)[2]	**25,400**	27,793	53,555
Net Debt	**377,055**	429,671	141,904
Debt / Trailing Annual Cash Flow (times)	**1.1**	3.2	1.9
NETBACKS ($/BOE)			
Revenues	**$ 50.01**	$ 39.18	$ 29.62
Royalties	**$ (8.47)**	$ (6.61)	$ (4.07)
As a % of revenue	**16.9%**	16.9%	13.7%
Risk Management gain/loss (excluding electricity)	**$ (5.94)**	$ (6.43)	$ (4.67)
Operating expense (including electricity gains)	**$ (9.07)**	$ (8.43)	$ (8.94)
Operating Netback	**$ 26.53**	$ 17.71	$ 11.94
General & Administrative Expense	**$ (1.02)**	$ (0.87)	$ (1.02)
Interest Expense	**$ (2.36)**	$ (2.02)	$ (0.97)
Cash Flow netback	**$ 23.15**	$ 14.82	$ 9.95
Trust units outstanding at period end	**52,982,567**	41,788,500	17,109,006
Trust unit trading price at period end (TSX)	**$ 37.19**	$ 22.95	$ 14.07
Trust unit trading price at period end ($U.S. – NYSE)	**$ 32.01**	n/a	n/a
Total Average daily trading volume	**456,471**	192,066	29,746
PRODUCTION			
Light/Medium oil (Bbl/d)	**17,950**	12,336	5,314
Heavy oil production (Bbl/d)	**13,747**	8,495	5,444
Natural gas liquids production (Bbl/d)	**824**	472	64
Natural gas production (mcf/d)	**26,461**	10,999	1,311
Average daily production (BOE/d)	**36,571**	23,136	11,040
RESERVES (2005 figures are proforma)			
Total proved reserves (gross) (MBOE)	**151,591**	75,045	27,216
Total proved reserves Reserve Life Index (RLI) (years)	**6.9**	0.0	0.0
Proved plus probable reserves (gross) (MBOE)	**206,254**	102,512	33,037
Proved plus probable RLI (years)	**9.4**	7.4	6.2

[1] Assuming Trust Unit held throughout the period
[2] Excludes future tax, unit based compensation expense liability and fair value of risk management contracts

MANAGEMENT TEAM

John Zahary, P. Eng.
President & CEO

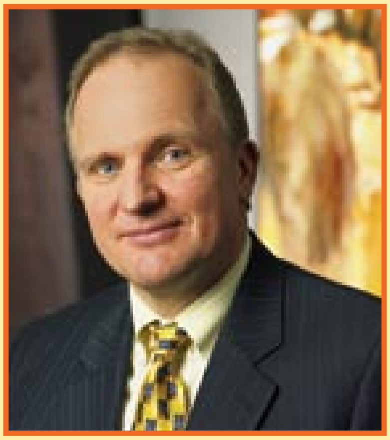


James Campbell
Vice President, Geosciences

Robert Fotheringham, C.A.
Vice President, Finance & CFO

Rob Morgan, P. Eng.
Vice President, Engineering & COO

Al Ralston
Vice President, Production



Jacob Roorda, P. Eng.
Vice President, Corporate

MESSAGE TO UNITHOLDERS

2005 proved to be another very successful year for Harvest, reporting record cash flows and production, executing a significant internal capital program with top-tier finding and development costs, and delivering the best rate of return of any conventional energy trust.

Harvest delivered these results while continuing to execute on its strategy and evolve with the changing landscape for Canadian energy royalty trusts. While oil and natural gas trusts and producers benefited from rising crude oil and natural gas prices, the strong commodity price environment also created some challenges across the energy sector. Asset acquisition costs increased, along with the number of competitors bidding on those assets. We also witnessed a dramatic rise in the costs and competition for drilling rigs and services. As we have done historically, we are adapting to meet these challenges.

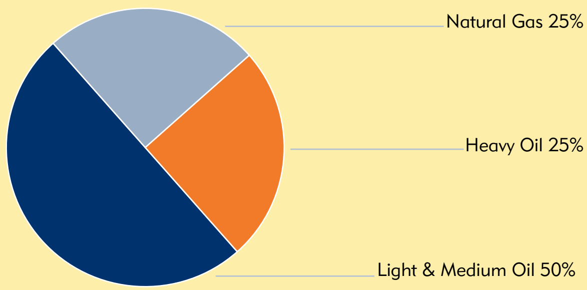
We have taken several key steps in this regard. First, we acquired an additional core property in Northeast British Columbia (Hay River) which enhanced our internal drilling and development inventory. Second, we completed a listing on the New York Stock Exchange (NYSE) in July of 2005 to broaden our access to capital. This was a natural progression from the U.S.$250 million senior note offering completed in the U.S. in 2004. Third, we completed a merger with Viking Energy Royalty Trust in February of 2006.

HAY RIVER ACQUISITION

Harvest successfully concluded the $238 million acquisition of the 5,200 BOE/d Hay River property in August 2005, at favourable acquisition metrics. Harvest believes that this particular asset offers Harvest significant possibilities for reserve accretion. Production at Hay River is medium gravity crude oil, which receives a price which is based on Edmonton Light oil, rather than on medium gravity crude benchmarks, as it is sold into a light oil pipeline stream. This reduces the discount and volatility of the realized price. As a result of the premium pricing and lower operating costs in the area, we realize higher netbacks from our Hay River production.

Hay River is situated on approximately 200 million barrels of original resource in place and the independent engineering reflects a lower ultimate recovery factor than what we believe to be achievable. In addition, Hay River has a significant gas cap, which our independent engineering assumes will be required for pressure maintenance to produce the oil, before it can be produced. We believe there is a possibility that

Harvest's production base is well diversified, with 50% light medium oil, 25% heavy oil/oil sands and 25% natural gas.



DIVERSIFIED PRODUCTION BASE (%)

pressure maintenance can be provided by a waterflood, which would allow us to begin producing gas from this property in the near future. This affords Harvest a depth of excellent development opportunities to improve reserve recovery. Our 2006 capital development budget has allocated over $50 million for development at Hay River alone, and we expect to drill approximately 20 wells in the area.

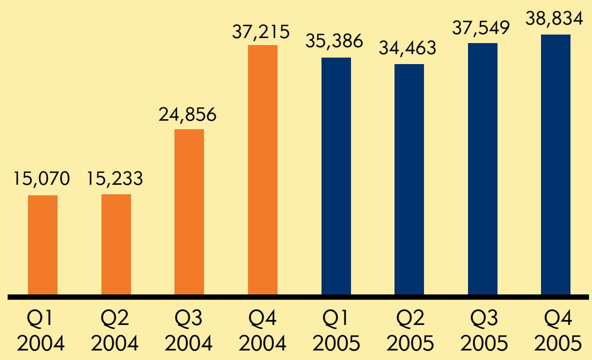
ACCESS TO CAPITAL

As the cost of acquisitions and development programs have escalated, accessing both debt and equity at a reasonable cost presents a key differentiating factor for trusts. We have made great strides in this area during the past two years. First, we accessed the high-yield debt market in 2004, and listed our Trust Units on the NYSE in 2005. These steps have provided Harvest with access to the largest capital market in the world, and significantly improved liquidity for existing Unitholders, with average daily trading volume increasing from 100,000 units per day to over 400,000 Units per day.

We have reduced total debt significantly from 2004, with total debt to fourth quarter annualized cash flow at 0.9 times at the end of 2005 compared to 1.9 times at the end of 2004. We have also increased the amount of undrawn bank capacity from $250 million at the end of 2004 to approximately $740 million upon completing syndication of our credit facility. With the Viking arrangement, we have improved our borrowing cost, and we expect this to improve further, providing even better access to debt markets with lower risk. As a result of our strong balance sheet, large undrawn credit facility and NYSE listing, our capital structure affords us greater financial flexibility. All of these are great tools as we look forward to growing the Trust in the future.

VIKING ARRANGEMENT

Consistent with our continued commitment to value creation, Harvest merged with Viking Energy Royalty Trust in early 2006. A significant driver behind this merger was the belief that the long-term sustainability of Harvest would be improved by combining our two organizations. Our similar strategies, cultures, operational practices and the technical nature of our people and assets made for a logical combination. Although this transaction was not immediately accretive to Harvest Unitholders, Harvest achieved several key benefits: (i) a more balanced production portfolio with a greater exposure to natural gas; (ii) a longer reserve life index (RLI – 9.4); (iii) an increased land base and drilling inventory; and (iv) a deeper technical and management team. In addition, as previously noted, *Through a combination of value-added acquisitions and efficient internal development, Harvest more than doubled its quarterly production from the first quarter of 2004 to the fourth quarter of 2005.*



QUARTERLY PRODUCTION (BOE/d)

we believe the larger entity has a significant cost of capital advantage. We strongly believe these benefits will be felt in 2006 and future years by making Harvest more competitive.

LONG-TERM SUSTAINABILITY

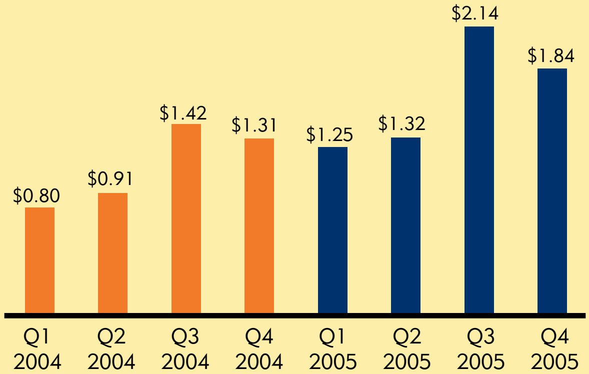
The key steps taken in the last 12 months have improved Harvest's long-term sustainability – our key goal. Sustainability is the ability to replace produced reserves while maintaining or increasing cash flow per unit. As you will see from reviewing our operating and financial results, Harvest has increased reserves per unit, on a debt-adjusted basis, in each year of its existence. Cash flow per unit has also increased each year. Although rising commodity prices have certainly been a factor in that, so has our top-tier finding and development costs, our efforts to control operating costs and a focus on recycle ratio. Over the past four years, we have outperformed our trust peer averages on capital efficiencies, and added new reserves at lower costs than the sector average.

One of Harvest's hallmarks is our strategy of 'maximizing the value of every barrel'. By taking a hands-on operational and technical approach to our asset base, seeking to reduce costs and increase margins, we continuously strive to enhance the recovery of our reserves. Historically, trusts have relied primarily on acquisitions for reserve replacement, but increased competition and higher asset prices reinforce the need to maintain a deep inventory of internal development opportunities. With at least three years' worth of drilling opportunities, we are less reliant on acquisitions and can continue to make acquisitions based on value creation as opportunities arise.

In addition to controlling costs and managing capital efficiencies, hedging and risk management are very important aspects of our business. Harvest has maintained an active commodity price hedging program, but we have evolved that program to reflect current market realities. Our current contracts are not swaps which cap upside participation; rather, we secure a firm floor price, but allow Harvest to participate in the upside. In June of 2005 we expanded our hedging program to include two heavy oil price differential hedges on 10,000 barrels of oil per day. By hedging this risk, we have minimized one of the disadvantages of heavy oil, while retaining its inherently lower development costs, thus improving its economics.

We also hedge our power costs by fixing the price of our electricity usage, and limiting the impact of electricity price spikes. These hedges allowed us to minimize the

With increasing production, operating cost control and rising commodity prices, Harvest has experienced significant cash flow per unit growth.



QUARTERLY CASH FLOW PER UNIT ($/unit, Basic)

impact of volatile power costs on our 2005 operating costs. We have hedged approximately 65% of our estimated 2006 Alberta power consumption at $51.48 per megawatt hour, and 52% of our estimated Alberta power consumption at $56.69 per megawatt hour in 2007 and 2008.

We believe it is prudent for Harvest to enter into contracts that provide for some downward oil price protection, and fix electricity prices, in a manner consistent with our goal of sustainability.

In response to the strong commodity price environment and to avoid paying income tax, we raised our monthly distribution by 75% in two separate increases during 2005. From inception to the end of 2005, Harvest has paid out more in cumulative distributions per Trust Unit than our Initial Public Offering (IPO) price of $8.00, plus we have delivered Unit price appreciation of 365% over the same period. This has resulted in a total return to Unitholders of 76% in 2005 and a total return to Unitholders of 661% since inception. We believe this demonstrates the success of executing on our strategy.

SECURING OUR FUTURE

We are now one of the largest conventional energy royalty trusts in Canada, with a balanced production and reserve base, a significant inventory of development opportunities in our core areas, an ongoing focus on enhanced oil recovery methods, and an operational and management team with significant experience and technical expertise.

In 2006, we will invest approximately $250 million in our capital development program, and focus on drilling in our Markerville, Hay River, Southeast Saskatchewan and Hayter areas. We have budgeted to drill approximately 250 gross wells during the year, and remain committed to efficiently deploying our capital, and effectively controlling our costs. Risk management and hedging will continue to be methods we use to underpin our cash flows and distributions. We will maintain our existing operational principles and fundamental strategies of maximizing our oil and natural gas production and development.

I look forward to reporting to you on our results regularly as we embark on another exciting stage for Harvest.

(signed) "John Zahary"

John Zahary
President & Chief Executive Officer
April 28, 2006

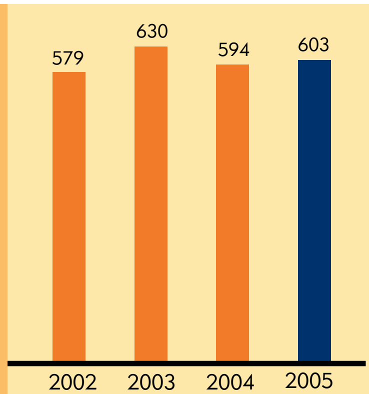
PUTTING IT ALL

OPPORTUNITY IN THE ASSET BASE

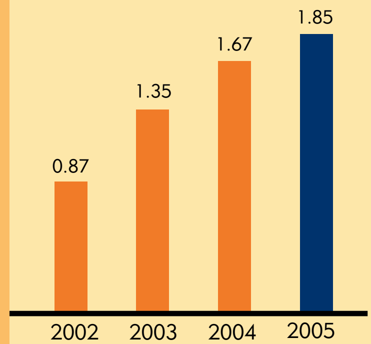
Our sizeable resource and opportunity portfolio enables Harvest to continue pursuing development opportunities in our extensive and attractive asset base. As well, we have many medium and longer term recovery opportunities such as expanded waterfloods, improved water handling, tight gas development and further exploitation of our large medium/heavy & oil sands production. Our extensive land base provides exploration or farm-out potential, while our concentrated core areas provide consolidation opportunities.

IMPROVED RECOVERY

With access to over 1.8 billion BOE of hydrocarbon on our working interest lands, each incremental 1% increase in recovery equates to an additional 18 million barrels of production. Harvest is focused on improving our resource recovery and estimate that we could generate an incremental 5-10% over and above our expected recovery factor.



DEBT ADJUSTED PRODUCTION PER UNIT– EXIT PRODUCTION (BOE/d per million units)



DEBT ADJUSTED RESERVES PER UNIT (BOE per unit)

OPERATIONAL ASSET SUSTAINABILITY

Effectively exploiting our significant hydrocarbon-rich asset base is made possible by our experienced technical team, whose focus is to develop the resource potential to generate incremental production, reserves and ultimately, cash flow.

FINANCIAL SUSTAINABILITY

Furthering our goal of sustainability requires us to create a balance between yield and retained cash flow for reinvestment. This retained cash flow is supported by our conservative leverage position, significant committed undrawn debt capacity, and our active (40%+) Distribution Reinvestment Plan participation.

2006 OUTLOOK

Capital spending on drilling and other development opportunities in 2006 is budgeted at $250 million; 75% of which is allocated to drilling approximately 250 gross wells. We anticipate that with the execution of this capital program and given our ability to attract and retain key services and personnel, our 2006 production will average approximately 60,000 BOE/d.

CORE AREAS

CORE AREA SNAPSHOT

	Estimated 2006 Production (BOE/d)	Primary Product	2006 Capital Program ($MM)	2006 Drilling (gross)
Northern	10,700	Light & medium oil 24 – 38° API	80	45
Western	10,200	Natural gas	50	60
Eastern	20,500	Medium & heavy oil 12 – 27° API	60	80
Southern	12,300	Oil and natural gas 11.5 – 33° API	30	35
S.E. Saskatchewan	6,300	Light oil 28 – 33° API	30	30

HARVEST'S Q4 2005 PROFORMA PRODUCTION – TOP 10 PRODUCING PROPERTIES

Property Name	Average Q4 2005 Production (BOE/d)	Primary Product
Suffield	6,421	Oil
Southeast Saskatchewan	4,995	Oil
Hay River	4,853	Oil
Markerville	4,446	Natural Gas & NGL
Hayter	4,216	Oil
Bellshill Lake /Thompson Lake	4,178	Oil
Wainwright/Viking Kinsella	2,898	Oil
Crossfield	2,432	Natural Gas & NGL
Red Earth	2,003	Oil
Bashaw	1,533	Oil
Other Properties	24,855	
Total	62,830	

Harvest is focused on the efficient and effective operation of our high quality properties, currently situated within five core areas across Western Canada. We employ a disciplined approach to the oil and natural gas production business, whereby we acquire high working interest, operated producing properties and employ our value-creating management and operational practices. These practices include diligent, hands-on management to maintain and maximize production rates, application of technology and selective capital investment to maximize reservoir recovery, enhancing operational efficiencies to control and reduce expenses, and unique marketing arrangements and corporate risk management techniques to effectively manage cash flow.

Our asset base holds significant quantities of unexploited hydrocarbon, providing us with the opportunity for future internal development, with the goal of creating additional value for unitholders. We have an attractive commodity mix, with 50% of our production weighted to light/medium oil, 25% weighted to heavy oil/oil sands and 25% weighted to natural gas. Our proved plus probable Reserve Life Index is 9.4 years. While there has been substantial change and evolution at Harvest over the past few years, our principles around value creation remain unchanged.

Harvest has five core areas of operation across Western Canada: Northern, Western, Eastern, Southern and Southeast Saskatchewan.

NORTHERN, ALBERTA

Properties in Harvest's Northern Core area are located in northern Alberta and Northeast British Columbia and produce light and medium gravity crude oil. Key properties within this area are Red Earth and Hay River.

RED EARTH

Harvest's Red Earth property produces high netback light, sweet crude (38° API) from the Granite Wash and Slave Point formations. The extensive land base offers excellent medium and longer term development opportunities through light oil development and waterflood enhancement. In 2006, Harvest has budgeted to spend approximately $16 million in the area, and plans to drill approximately 19 gross wells. Further working interest consolidation of our land base also represents a growth opportunity as we begin to dominate operations in the area.

HAY RIVER

The other key property within the Northern area is Hay River, located in north east B.C. Harvest acquired Hay River in August of 2005 and this 100% owned and operated area has become a significant development area for Harvest. Production at Hay River is medium gravity crude oil (24° API) from the Bluesky formation and realizes higher netbacks due to low operating costs and realized prices that are only 17% less than the Edmonton Light oil (40° API) benchmark price. Harvest anticipates a capital investment of approximately $50 million in 2006, with plans to drill approximately 20 gross wells.

The map and highlights to the right provide a summary of Hay River.

WESTERN CORE AREA, ALBERTA

Properties in the Western Core area produce primarily natural gas and natural gas liquids. Two key properties within this area are Markerville and Alexis.

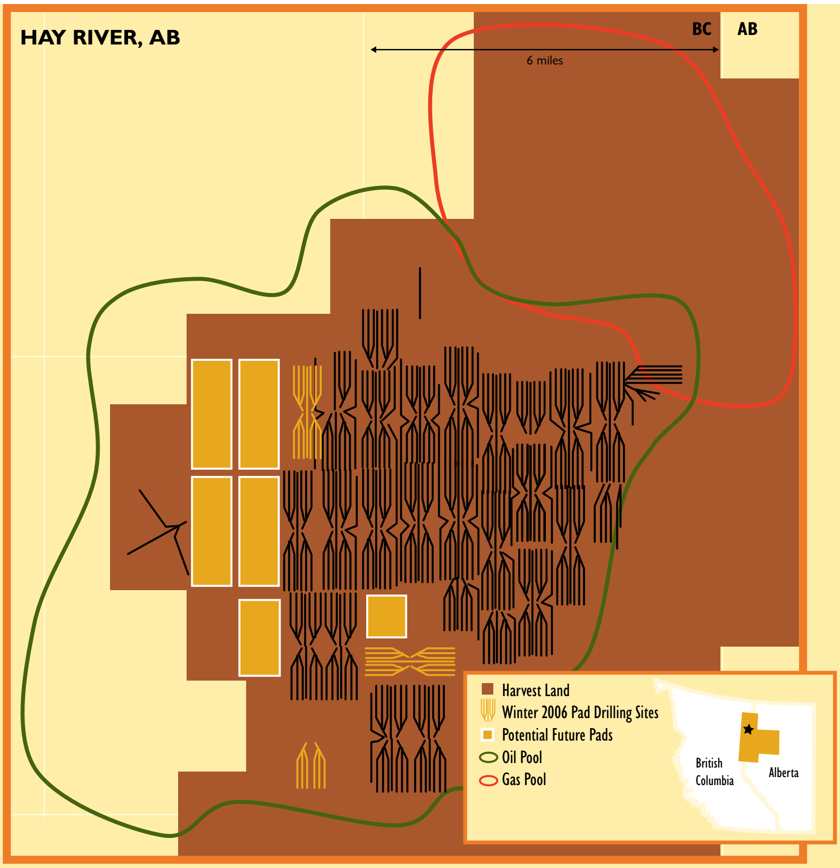
MARKERVILLE

Markerville is the largest producing property in the Western area, and produces liquids rich, sweet natural gas. The two main producing formations in this area are the Pekisko Carbonate and Edmonton Sands tight gas plays. The Pekisko formation is developed using both vertical and horizontal wells at a depth of approximately 7,200 feet, while the Edmonton Sands formation is developed exclusively with vertical wells at depths of approximately 2,000 feet. Plans for 2006 include the drilling of three Pekisko horizontal wells and approximately 42 Edmonton Sands wells, for a total expenditure of approximately $26 million.

Markerville is summarized on the map and highlights to the right.

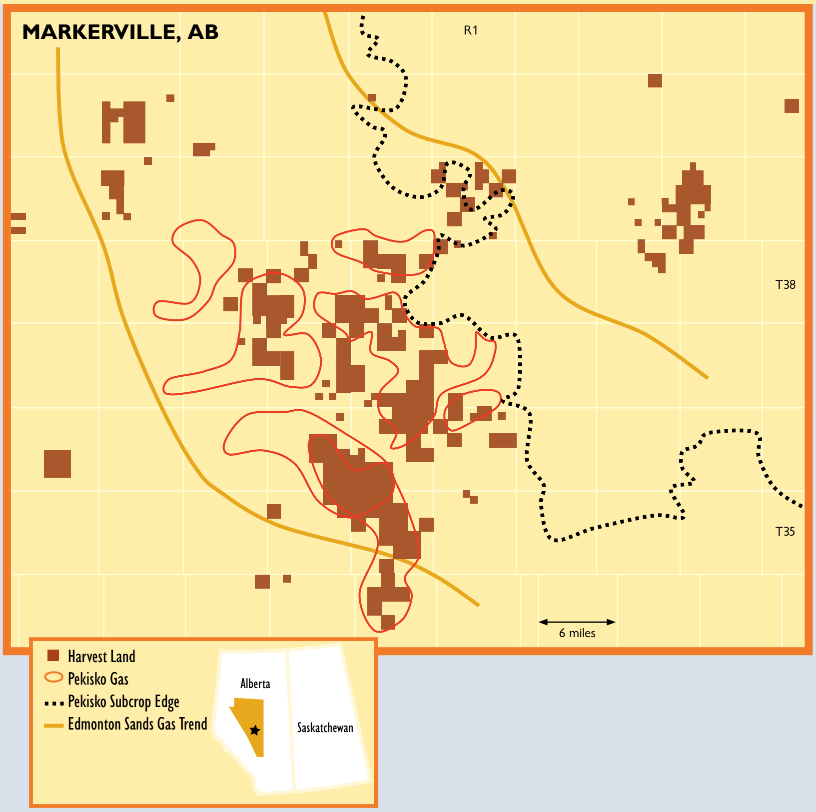
ALEXIS

The Alexis property produces both natural gas and crude oil, primarily from the Banff and Nordegg formations. In 2006, the development program is budgeted at $3 million which will include the drilling of up to 5 delineation and infill drilling locations, facility modifications and workover and optimization projects.



HAY RIVER SNAPSHOT

- > Bluesky medium gravity oil
- > Estimated Original Oil in Place (OOIP) = 200 MMbbls
- > Estimated current recovery factor – 6%
- > Estimated recovery factor including booked year end 2005 P+P reserves – 16%
- > Expect to be able to increase recovery to greater than 20%
- > Effect of 3% increase in recovery = 6 MMBOE additional recovery
- > Development in Hay River includes pump upgrades, continued waterflood optimization and drilling downspacing to increase the recovery factor. The accompanying map shows existing drilling pad sites, as well as future drilling locations.



MARKERVILLE SNAPSHOT

- > Estimated Original Resource in Place – 50 MMBOE
- > Estimated current recovery factor – 27%
- > Estimated recovery factor including booked year end 2005 P+P reserves – 58%
- > Expect to be able to increase recovery factor to 68% with down spacing
- > Effect of 10% increase in recovery = 5 MMBOE additional recovery
- >$26 million capital program in 2006 will continue exploitation of this area through downspacing and drilling approximately 45 wells.

EASTERN CORE AREA, ALBERTA

Harvest's original Eastern Alberta area has been expanded with subsequent acquisitions. With large pools and significant original oil in place, Eastern Alberta is Harvest's largest producing core area, and continues to provide strong production and development opportunities.

BELLSHILL LAKE

This property produces medium gravity (26-28° API) crude oil from the Ellerslie and Dina formations. The 2006 capital program at Bellshill Lake is budgeted at approximately $5 million and is expected to include the drilling of up to 5 gross infill wells and facility modifications to increase fluid handling capacity at the central processing facility.

WAINWRIGHT

This property produces heavy oil (20° API) from the Cretaceous Upper Mannville Sparky formation. Development in 2006 is budgeted at $6 million, and expected to include up to 14 infill and step-out drilling locations, field optimization, and debottlenecking the water injection system to reduce operating expenses.

HAYTER

Hayter produces 15-18° API from the Lower Cretaceous Dina and Cretaceous Sparky formations. The 2006 capital in Hayter will include the drilling of up to 12 horizontal wells in the Dina formation, and up to 8 vertical wells in the Sparky formation, for a total capital expenditure of $12 million.

Our Eastern area is summarized on the map and highlights to the right.

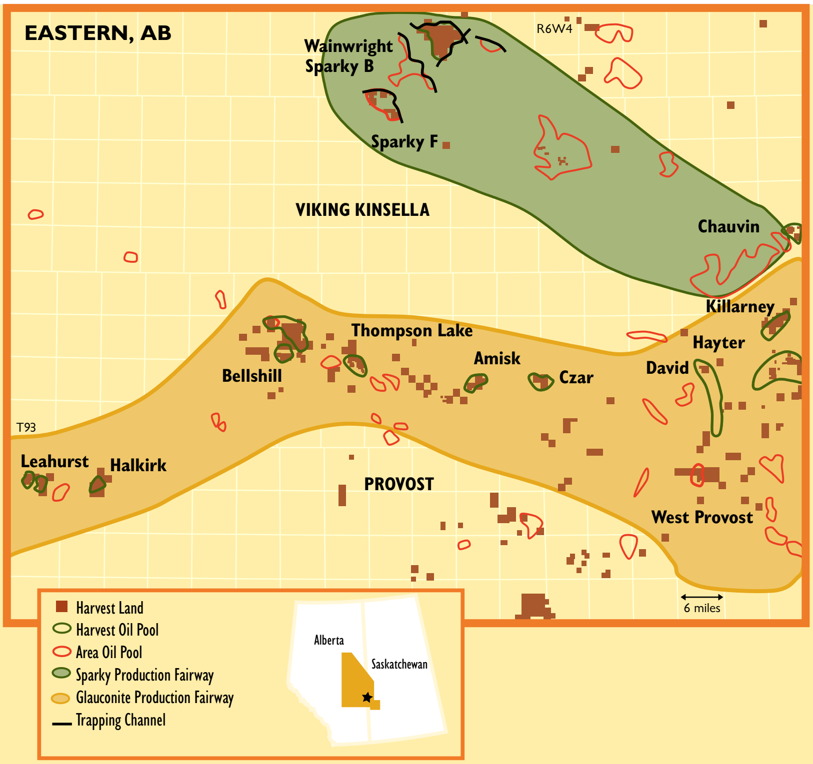
SOUTHERN CORE AREA, ALBERTA

Properties in the Southern Core area produce primarily heavy crude oil and natural gas. Harvest's largest single producing property, Suffield, is located in this area.

SUFFIELD

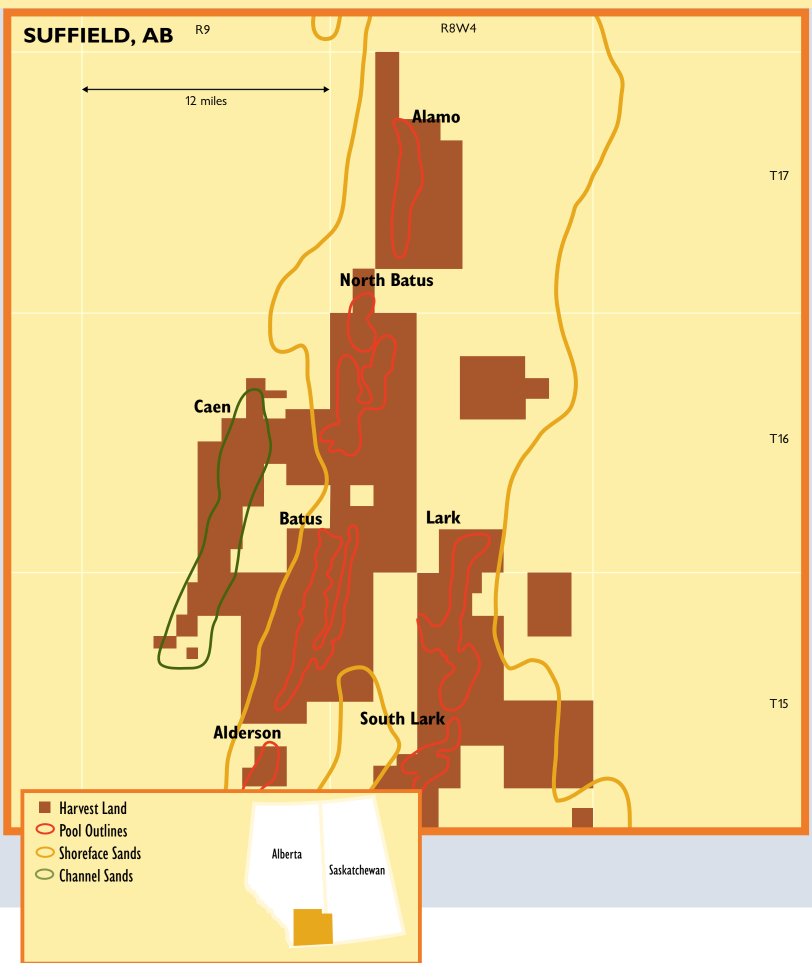
Harvest's Suffield property produces heavy oil of approximately 14° API. Suffield is Harvest's largest single producing property, with production from the Glauconite & Viking formations. Development in 2006 will include the drilling of approximately 20 horizontal wells at an estimated cost of approximately $23 million. In addition, upgrades to the water handling facilities will improve our ability to optimize production on both the new drilling as well as the existing wells at an estimated cost of $6 million.

The map and highlights to the right provide a summary of Suffield.



EASTERN CORE AREA SNAPSHOT

- Four Major Pools in Harvest's Eastern Area have greater than 50 MMBOE of Original Oil in Place (OOIP) – Wainwright, Hayter, Bellshill & Thompson Lake
- Harvest's estimated working interest OOIP from these four pools: 590 MMBOE
- Estimated recovery factor including booked year end 2005 P+P reserves – 42.5%
- Expect to be able to increase recovery factor to 47% with infill drilling, optimization & waterflood
- $60 million capital program in 2006 will continue exploitation of this area through production additions, cost reductions, and drilling approximately 80 gross wells.



SUFFIELD SNAPSHOT

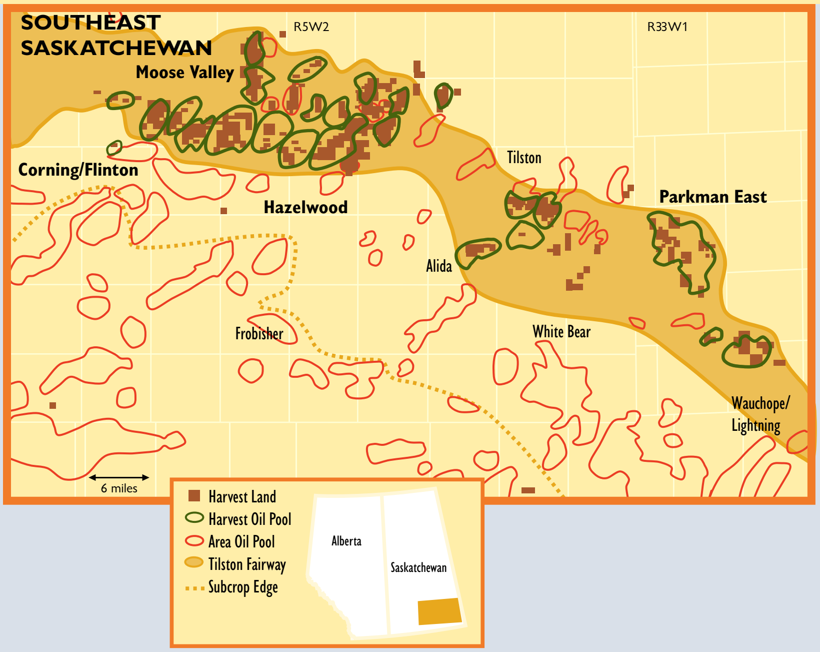
- Estimated Original Oil in Place: 170 MMBOE
- Estimated current recovery factor – 8%
- Estimated recovery factor including booked year end 2005 P+P reserves – 18%
- Expect to be able to increase recovery factor to 22% with infill drilling, optimization & artificial lift
- $30 million capital program in 2006 includes step-out, extension and infill drilling of 20 gross wells, as well as facility upgrades.

SE SASKATCHEWAN CORE AREA

Properties in Harvest's Saskatchewan area produce exclusively light gravity crude oil. The Trust has established a dominant position in the major oil pools of the Tilston formation, and has recently identified other hydrocarbon bearing zones that may offer incremental productive potential. The key properties within this area are Hazelwood/Moose Valley.

HAZELWOOD/MOOSE VALLEY

Hazelwood/Moose Valley produces light crude oil (28-33° API). This property continues to generate strong netbacks and is an area of production growth for Harvest, given historical development success and a large inventory of future opportunities. In 2006, Harvest plans to spend approximately $30 million in capital development, which will include horizontal step-out and infill drilling of up to 30 locations.



S.E. SASKATCHEWAN SNAPSHOT

> Estimated Original Oil in Place at Hazelwood/Moose Valley: 176 mmbbl

> Estimated current recovery factor – 16%

> Estimated recovery factor including booked year end 2005 P+P reserves – 22%

> Expect to be able to increase recovery factor to 27% with infill drilling

> $30 million capital program in 2006 includes drilling approximately 30 gross wells. Base optimization is all production, while future potential may include new pool discoveries.

RESERVES DISCLOSURE

The following tables are an aggregate roll-up of the Harvest reserves and Viking Energy Royalty Trust reserves, prepared as at March 20, 2006 assuming that all reserves were held by Harvest as at December 31, 2005. The Harvest and Viking reserves were evaluated by the independent reserve evaluators McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd., and Sproule Associates Limited in accordance with National Instrument 51-101 ("NI 51-101") for the year ended December 31, 2005. For the purposes of the following tables, Harvest and Viking's reserves were both evaluated using the forecast price and cost assumptions of McDaniel & Associates Consultants Ltd. Complete NI 51-101 oil and gas reserves disclosure for both Harvest and Viking on a "stand-alone" basis as at December 31, 2005 are included in Harvest's Annual Information Form dated March 30, 2006 and filed on SEDAR or available on Harvest's website at www.harvestenergy.ca. Reserves data presented below are net of abandonment costs.

Oil equivalent amounts referenced in the following reserves disclosure have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

HARVEST PROFORMA RESERVES INFORMATION

Harvest Proforma Reserves Summary – Forecast Prices and Costs as at December 31, 2005

Gross(1)

Reserves Category	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Associated & Non-Associated Gas (mmcf)	Total Oil Equivalent (Mboe)
Proved					
Developed Producing	62,341.2	32,280.3	5,082.5	189,532.3	131,340.7
Developed Non-Producing	1,155.7	1,826.0	343.2	27,326.1	7,882.3
Undeveloped	6,292.7	4,564.4	234.9	7,964.3	12,419.4
Total Proved	69,789.6	38,670.7	5,660.6	224,822.7	151,591.4
Probable	23,139.4	17,971.2	1,684.9	70,726.9	54,610.3
Total Proved Plus Probable	92,929.0	56,641.9	7,345.5	295,549.6	206,254.7

Net(2)

Reserves Category	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Associated & Non-Associated Gas (mmcf)	Total Oil Equivalent (Mboe)
Proved					
Developed Producing	55,879.8	29,171.7	3,919.7	156,563.5	115,103.1
Developed Non-Producing	1,034.8	1,521.0	255.5	22,493.8	6,560.3
Undeveloped	5,181.7	3,850.7	170.8	6,378.0	10,266.2
Total Proved	62,096.3	34,543.4	4,345.9	185,435.3	131,891.5
Probable	20,219.3	15,864.4	1,278.3	58,466.7	47,133.5
Total Proved Plus Probable	82,315.6	50,407.8	5,624.2	243,902.0	179,066.9

Notes:

(1) "Gross" reserves means the total working interest share of Harvest's remaining recoverable reserves before deductions of royalties payable to others.

(2) "Net" reserves means Harvest's gross reserves less all royalties payable to others.

(3) Columns may not add due to rounding.

(4) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11.4 MMboe, Proved Undeveloped: 3.4 MMboe, Total Proved: 14.9 MMboe, Probable: 3.9 MMboe and Proved plus Probable: 18.7 MMboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts:Proved Developed Producing: 10.1 MMboe, Proved Undeveloped: 2.8 MMboe, Total Proved: 12.9 MMboe, Probable: 3.2 MMboe, and Proved plus Probable: 16.1 MMboe.

Harvest Proforma Net Present Value of Reserves – Forecast Prices and Costs as at December 31, 2005

Harvest's proforma crude oil, natural gas and natural gas liquids reserves were evaluated using McDaniel's product price forecasts effective January 1, 2006 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that McDaniel's estimates of the discounted future net production revenue represent the fair market value of Harvest's proforma reserves.

Reserves Category	0% ($millions)	5% ($millions)	10% ($millions)	15% ($millions)	20% ($millions)
Proved					
Developed Producing	3,134.5	2,519.0	2,146.0	1,891.1	1,703.7
Developed Non-Producing	233.8	167.3	131.9	110.1	95.2
Undeveloped	226.3	181.1	145.8	118.4	96.8
Total Proved	3,594.5	2,867.4	2,423.7	2,119.6	1,895.7
Probable	1,422.3	905.0	648.8	500.2	404.2
Total Proved Plus Probable	5,016.8	3,772.4	3,072.5	2,619.8	2,299.9

Note:

(1) Columns may not add due to rounding.

McDaniel & Associates Consultants Ltd. January 1, 2006 Price Forecast

A summary of the McDaniel price forecast as at January 1, 2006 that was used in both the Harvest reserves evaluation and the Viking reserves evaluation is listed below. A complete listing of the price forecast is available on the McDaniel's website at the following link http://www.mcdan.com/forecasts.html.

Year	WTI Crude Oil $US/bbl (1)	Edmonton Light Crude Oil $C/bbl (2)	Alberta Bow River River Hardisty Crude Oil $C/bbl (3)	Alberta Heavy Crude Oil $C/bbl (4)	Alberta AECO Spot Price $C/GJ	US/CAN Exchange Rate $US/$CAN
2006	57.50	66.60	45.70	35.50	10.05	0.850
2007	55.40	64.20	45.30	36.10	9.05	0.850
2008	52.50	60.70	44.00	36.00	8.05	0.850
2009	49.50	57.20	42.60	35.30	7.00	0.850
2010	46.90	54.10	40.30	33.40	6.55	0.850

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur

(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur

(3) Bow River at Hardisty Alberta (Heavy stream)

(4) Heavy crude oil 12° API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)

2005 RESERVE LIFE INDEX

The following reserve life index values were derived by dividing the total reserves by Harvest's average 2006 forecast production for the full year – approximately 60,000 BOE/d.

Total Proved plus Probable:	**9.4**
Total Proved:	6.9
Proved Producing:	6.0

CORPORATE GOVERNANCE

As the corporate and regulatory landscape continues to change, Harvest's corporate governance practices have and will continue to grow and evolve accordingly. A summary of our corporate governance practices and compliance with National Instrument 58-101 is contained in our 2006 Proxy Statement and Information Circular.

We currently fully comply with the existing corporate governance guidelines for Canadian issuers. Nevertheless we are committed to enhance the responsibilities of the committees to ensure their mandates will meet or exceed changes to corporate governance guidelines which may occur in the future. In 2006, Harvest is on schedule to be in compliance with the relevant internal control and disclosure certification requirements of the U.S. Sarbanes-Oxley Act. This process will benefit Harvest's Unitholders as it formalizes our commitment to implement processes and controls that promote sound business practices at all levels of the Trust. Harvest's current corporate governance practices do not materially differ from those outlined by the Securities & Exchange Commission ("SEC") or the New York Stock Exchange ("NYSE"). Harvest has also implemented a whistleblower policy which allows members of the organization to anonymously report known violations of the code of ethics.

The Board consists of nine independent, non-executive directors, all of whom have extensive industry experience. Three permanent committees of the Board have been established as follows:

Audit Committee: The members of the Audit Committee are Messrs. McFadyen (Chairman of the Committee), Johnson and Blue. Each of the Audit Committee members have years of experience managing large organizations, and each has served on numerous boards, including internationally. The Audit Committee reviews and approves all financial statements on a quarterly basis. In addition, it reviews annual financial statements independently with the auditors of the Trust, prior to presentation of such statements to the Board of Directors for approval. The Audit Committee reviews the integrity of management's reporting systems and also reviews management reporting, internal financial and operating controls, policies and practices with management and the auditors of the Trust.

Compensation Committee / Corporate Governance Committee: The Compensation and Corporate Governance Committees are comprised of Messrs. Chernoff (Chairman of the Committee), Brussa and Friley. The primary function of the Compensation / Corporate Governance Committee is to assist the Board in fulfilling its oversight responsibilities with respect to human resources policies, compensation, succession planning and proposing new board nominees and assessing directors. The Committee is also responsible to review and recommend to the Board management's succession plan including provisions for appointing, training and monitoring senior management, reviewing the effectiveness of the Board and its committees, and reviewing the appropriateness of the current and future organizational structure of the Trust.

Reserves, Safety & Environment Committee: The Reserves, Safety and Environment Committee is comprised of Kevin Bennett (Chairman of the committee), David Boone and Hank Swartout. The purpose of this Committee includes the review of annual independent reserve engineering evaluation reports, reviewing the qualifications, experience and independence and meeting with the independent reserve evaluators who prepare such reports. This Committee also assists directors in meeting their responsibilities (especially for accountability) in respect of Harvest's legal, industry and community obligations pertaining to the areas of health, safety and environment, as well as the establishment and implementation of appropriate environment, health and safety policies and procedures.

ENVIRONMENT, HEALTH AND SAFETY

Harvest is committed to protecting the health and safety of our employees, contractors, residents of communities in which we operate, and the environment we all share. Our commitment to excel in the area of environment, health and safety (EH&S) is an important strategic element of Harvest's business model. We employ best practices in all operational areas to comply with relevant regulations and guidelines, and to ensure the highest quality of work. Our team applies sound operational practices, and we are always striving to improve our techniques and processes. For Harvest, standards are not viewed as targets to be reached, but as levels to be exceeded.

Harvest has established internal environmental, health and safety guidelines and systems to ensure the health and safety of its employees, contractors and neighbouring residents and to ensure compliance with environmental laws, rules and regulations. These systems require Harvest to regularly conduct emergency response planning exercises to ensure its plans are effective and to inspect suspended wells, abandoned wells, as well as site restoration plans and activities. Harvest's Environment, Health and Safety team is responsible for monitoring regulatory requirements and when required, to implement appropriate compliance procedures and to cause our operations practices to be carried out in accordance with the applicable environmental requirements with adequate safety precautions.

Our genuine concern for the safety and well-being of our employees is demonstrated by our commitment to training and building the knowledge base of each individual. Harvest is a Platinum Level participant in the Environmental, Health and Safety Stewardship Program initiated by the Canadian Association of Petroleum Producers (CAPP). This stewardship program provides comparison on key benchmarks including recordable and lost time injuries for employees and contractors. As a Platinum Level participant, Harvest will conduct regular compliance audits of our safety program, will track and monitor our Green House Gas (GHG) emissions and report to CAPP annually.

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. 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 March 8, 2006. When reviewing our 2005 results and comparing them to 2004, readers are cautioned that the 2005 results include a full year of operations from our 2004 acquisitions and the Hay River acquisition for five months of 2005. The combination of these events significantly impact the comparability of our operations and financial results for 2005 to the results of 2004 as well as the comparability between quarters.

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.

2005 FINANCIAL AND OPERATING HIGHLIGHTS

- Cash Flows for 2005 totaled $309.8 million ($6.66 per Trust Unit), a 150% increase over $123.7 million ($4.94 per Trust Unit) earned in 2004.
- Distributions declared totaled $3.20 per Trust Unit in 2005 resulting in a payout ratio of 50% compared to $2.40 per Trust Unit declared in 2004 and a payout ratio of 52%.
- Total return of 76% for Unitholders in 2005 comprised of 62% capital appreciation and a cash on cash yield of 14%.
- Increased average daily production in 2005 by 58% to 36,571 BOE per day with consistent year over year production per Trust Unit on a debt adjusted basis.
- Capital asset additions in 2005 totaled $120.5 million compared to $42.7 million in 2004.

- Finding and development (F&D) costs of $10.73 per BOE on a proved plus probable ("P+P") basis, excluding future development costs and $13.10 per BOE including future development costs, reflecting a recycle ratio (operating netback divided by F&D cost) of 3.1. P+P reserves per Trust Unit, on a debt adjusted basis, increased 11% year over year, and our reserve life index (RLI) increased over the same period from 7.9 to 9.4, after inclusion of the effects of the merger with Viking Energy Royalty Trust.
- Improved balance sheet and financing flexibility in 2005, with debt to annualized Cash Flows of 0.9 times at December 31, 2005 compared to 1.9 times at the end of 2004. Subsequent to year end, secured a $750 million, largely undrawn 3 year term credit facility, with plans to syndicate it to $900 million by the end of March.
- Completed acquisition of Hay River property for cash consideration of $237.8 million adding 5,200 bbls per day of medium grade oil production and financed it with the issuance of $75 million of convertible debentures and $175 million of equity.
- Fourth quarter Cash Flow of $96.4 million which reflects a full quarter of incremental production from Hay River.
- Entered into an agreement to complete a merger with Viking Energy Royalty Trust ("Viking") to consolidate the technical skills and internal development opportunities of both organizations. Following the merger, Harvest is one of Canada's largest energy royalty trusts with a balanced production base (50% light/medium oil, 25% heavy oil and 25% natural gas) and significant long-term development opportunities.

The table below provides a summary of our financial and operating results for the twelve month periods ended December 31, 2005 and 2004. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Twelve months ended December 31		
FINANCIAL ($ thousands except where noted)	**2005**	2004	Change
		(Restated) (4)	
Revenue, net (1)	**436,452**	212,118	106%
Cash Flows (2)	**309,843**	123,710	150%
Per Trust Unit, basic (2)	**$ 6.66**	$ 4.94	35%
Per Trust Unit, diluted (2)	**$ 6.35**	$ 3.97	60%
Net income	**104,946**	11,241	834%
Per Trust Unit, basic	**$ 2.25**	$ 0.45	400%
Per Trust Unit, diluted	**$ 2.19**	$ 0.43	409%
Distributions declared (3)	**153,494**	64,563	138%
Distributions declared, per Trust Unit	**$ 3.20**	$ 2.40	33%
Payout ratio (2)(3)	**50%**	52%	(2%)
Capital asset additions (excluding acquisitions)	**120,508**	42,662	182%
Total daily sales volumes (BOE per day)	**36,571**	23,136	58%

	Harvest As at December 31, 2005		Harvest and Viking Proforma As at December 31, 2005	
RESERVES (MBOE)	**Gross**	**Net**	Gross	Net
Proved reserves	**87,731**	**77,557**	151,591	131,882
Probable reserves	**31,946**	**27,984**	54,663	47,175
Total proved plus probable (P+P) reserves	**119,677**	**105,541**	206,254	179,057

(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.

(4) Restated to reflect the adoption of new CICA recommendations to account for convertible debentures and exchangeable shares. See Note 3 to the Consolidated Financial Statements.

REVIEW OF OPERATIONS AND STRATEGY

Harvest is an oil and natural gas royalty trust, which focuses on the operation of quality petroleum and natural gas properties. We employ a disciplined approach to the oil and natural gas production business, whereby we acquire high working interest, large resource-in-place, mature producing properties and employ "best practice" technical and field operational processes to extract maximum value. These operational processes include: diligent hands-on management to maintain and maximize production rates, the application of technology and selective capital investment to maximize reservoir recovery, and the enhancement of operational efficiencies to control and reduce expenses.

Overall, we had a successful year with Cash Flow for the year ended December 31, 2005 of $309.8 million ($6.66 per Unit). This 150% increase in Cash Flow compared to the prior year is attributed to higher commodity prices, a full year of production from the acquisitions made in 2004 and incremental production from the Hay River acquisition.

Our Unitholders have received a 76% total return since the beginning of 2005, comprised of capital appreciation of 62% and a cash on cash yield of 14%.

Distribution increases were achieved while implementing a $120.5 million capital development program that was directed towards sustaining our production. Our capital development program is focused on growing and maintaining production with 94% of the costs directly related to drilling activities. We continue to focus on established resource plays that require fewer infrastructure investments. Our 2005 Finding & Development (F&D) costs before changes in future development capital ("FDC"), were $10.73 per BOE on a P+P reserve basis, and $11.80 per BOE on a Total Proved basis. Our capital program, together with our 2004 and 2005 acquisitions, contributed to a 58% increase in production from 23,136 BOE per day to 36,571 BOE per day in 2005.

We are continuously evaluating potential acquisition prospects that provide us additional development opportunities. On August 2, 2005, we closed the acquisition of the Hay River property for approximately $237.8 million. The Hay River property consists primarily of about 5,200 bbls per day of medium gravity crude produced in Northeastern British Columbia. The cost was approximately $46,000 per flowing BOE. The closing of the Hay River purchase occurred concurrently with a $250 million equity and convertible debenture financing. Our 2005 results reflect five months of production from Hay River.

The Hay River barrels sell at a premium to our average medium gravity crude oil production. The West Texas Intermediate ("WTI") realized price differential on our Hay River production was 14% while our remaining medium gravity crude production sold at an average differential of 34%. This, coupled with the impact of the lower Hay River operating expenses, improved our corporate netbacks for the year ended December 31, 2005. In the future, due to the 'winter only' access nature of this property, our first quarter results from Hay River will reflect higher operating and capital expenditures and lower production volumes than the remainder of the year. Our second quarter results should reflect the benefits of the activities undertaken in the first quarter, and as a result, the first quarter will not be indicative of the results expected for the balance of the year.

Cash Flows totaled $96.4 million (or $1.84 per Trust Unit) for the fourth quarter of 2005. This compares to fourth quarter 2004 Cash Flows of $52.9 million (or $1.31 per Trust Unit). Our 2005 exit Cash Flows nearly doubled over the prior year and reflect our higher operating netback. Our fourth quarter results provide an estimate for our future performance prior to the Viking Arrangement as this was the first full quarter including the results of our Hay River property.

On February 2, 2006, the security holders of Harvest and the Unitholders of Viking voted in favour of a resolution to effect a plan of arrangement (the "Arrangement") by which Unitholders of Viking received 0.25 Harvest Units for every Viking Unit held and Harvest acquired all of Viking's assets. As part of the Arrangement, Harvest assumed Viking's 10.5% and 6.40% unsecured subordinated convertible debentures and adjusted their conversion prices to $29.00 for the 10.5% series and $46.00 for the 6.40% series, consistent with the four to one exchange ratio under the Arrangement. At the time of writing and reflecting the Viking Arrangement, approximately 99.9 million Trust Units and approximately $252.8 million of convertible debentures are outstanding.

The Arrangement also enabled exchangeable shareholders to convert their exchangeable shares of Harvest Operations into Trust Units. As a result, 156,011 exchangeable shares were tendered, resulting in only 26,902 exchangeable shares remaining. Harvest intends to issue a notice to the remaining exchangeable shareholders to redeem these outstanding shares for cash in June 2006.

The combination of the two trusts created one of the largest conventional petroleum and natural gas trusts in North America with an initial enterprise value in excess of $4 billion. The merged entity has productive capacity of an estimated 64,000 BOE per day weighted approximately 50% to light and medium gravity oil, 25% to natural gas and 25% to heavy gravity oil. Although this transaction has no impact on the results for the year ended December 31, 2005, it will have a significant impact on the future results of Harvest.

REVIEW OF 2005 OPERATIONS

Commodity Price Environment

Benchmarks	2005	Year Ended December 31 2004	Change
West Texas Intermediate crude oil (US$ per bbl)	**56.56**	41.40	37%
Edmonton Light crude oil ($ per bbl)	**68.73**	52.54	31%
Bow River Blend crude oil ($ per bbl)	**44.28**	37.19	19%
AECO natural gas ($ per mcf)	**8.71**	6.53	33%
Canadian/U.S. dollar exchange rate	**0.825**	0.768	7%

The year ended December 31, 2005 saw record commodity prices and a strong Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate strengthened by 7%. This strengthening of the Canadian dollar partially offset gains in WTI for Canadian producers. While the U.S. dollar WTI strengthened by 37%, the Canadian dollar equivalent of WTI strengthened by 27%, a full 10% less than the U.S. dollar WTI equivalent. However, the differential between Edmonton Light crude oil prices and WTI narrowed from 2004 to 2005, which was more than offset by widening of the Bow River differentials to Edmonton Par in 2005 compared to those realized in 2004.

	2005				2004			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Light	**40.0%**	**28.2%**	**39.6%**	**36.6%**	39.1%	26.2%	26.6%	23.9%

To maintain stable Cash Flow and thereby stable distributions, we have implemented a commodity price risk management program which reduces the variability in our Cash Flow while allowing participation in price improvements. Further discussion regarding our risk management program is included under the heading "Risk Management Contracts".

Revenues

($ thousands)	2005	Year Ended December 31 2004	% Change
Light/medium oil sales	**$ 366,432**	$ 202,970	81%
Heavy oil sales	**197,863**	96,313	105%
Natural gas sales	**87,437**	25,455	243%
Natural gas liquids sales and other	**15,764**	7,071	123%
Total sales revenue	**667,496**	331,809	101%
Realized risk management contract losses [(1)]	**(79,271)**	(54,488)	45%
Net revenues including realized risk management contract losses	**588,225**	277,321	112%
Realized electricity price risk management contract gains	**6,290**	2,061	205%
Unrealized risk management contracts losses	**(45,061)**	(11,274)	300%
Net revenues, before royalties	**549,454**	268,108	105%
Royalties	**(113,002)**	(55,990)	102%
Net revenues	**$ 436,452**	$ 212,118	106%

(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/medium oil sales revenue for the year ended December 31, 2005 was $163.5 million (or 81%) higher than in the prior year as a result of a favourable price variance of $77.8 million and volume variance of $85.7 million. The favourable price variance relates to higher commodity prices in the year and a change in our product mix. Edmonton Par increased by 31% and Bow River increased by 19% over the prior year, which contributed significantly to the higher revenues realized for 2005. In addition, our product mix changed significantly with the acquisition of Hay River. Our average per barrel realized price for our medium grade properties, excluding Hay River, was $48.78 while our average realized per barrel price for the Hay River properties was $63.56 for the same period. Favorable volume variances are primarily due to the two significant acquisitions completed during the latter half of 2004 as well as the acquisition of the Hay River property in 2005, all of which substantially increased light/medium production volumes.

Heavy oil revenues for the year ended December 31, 2005 increased $101.6 million (or 105%) due to a favourable volume variance of $59.9 million and favourable price variance of $41.7 million. The acquisition we made in September of 2004 contributed additional heavy oil volumes and the rising crude oil price environment resulted in higher realized prices on our heavy oil.

Natural gas sales revenue increased by $62 million (or 243%) for the twelve months ended December 31, 2005 over the same period in the prior year. Record natural gas prices in 2005 resulted in a favourable natural gas sales revenue price variance of $26.4 million, and our acquisition of the Crossfield and Cavalier properties in 2004 were the primary contributors to a favourable volume variance of $35.6 million.

Natural gas liquids do not contribute significantly to our overall sales revenues. For the year ended December 31, 2005, natural gas liquids revenues increased by $8.7 million (or 123%) over the prior year, with the increase generally due to a higher pricing environment and higher production volumes resulting from our acquisitions in 2004.

Sales Volumes

The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2005		2004		%
	Volume	**Weighting**	Volume	Weighting	Change
Light/medium oil (bbl/d) (1)	**17,590**	**48%**	12,336	53%	43%
Heavy oil (bbl/d)	**13,747**	**38%**	8,495	37%	62%
Total oil (bbl/d)	**31,337**	**86%**	20,831	90%	50%
Natural gas liquids (bbl/d)	**824**	**2%**	472	2%	75%
Total liquids (bbl/d)	**32,161**	**88%**	21,303	92%	51%
Natural gas (mcf/d)	**26,461**	**12%**	10,999	8%	141%
Total oil equivalent (BOE/d)	**36,571**	**100%**	23,136	100%	58%

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

Full year 2005 average production was higher than in 2004 due to a full year of production from the 2004 acquisitions completed during the second half of 2004, as well as the incremental production from the Hay River property acquired in the third quarter of 2005. Our 2005 production was negatively impacted by unusually heavy rainfall and flooding in Alberta and Saskatchewan in the second quarter of 2005, with the impact extending to the third quarter as wet ground conditions resulted in additional downtime in many of the affected areas.

We do not intentionally manage to a specific production mix. The production mix is a result of our strategy of targeting accretive acquisitions and capitalizing on opportunities, rather than targeting specific commodity types. Our production mix in 2006 will be altered with the full year impact of the Hay River acquisition, and the completion of the Arrangement with Viking, such that approximately 50% of our production is weighted towards light/medium oil, 25% to natural gas and 25% to heavy oil.

Realized Commodity Prices

The following table provides a breakdown of our 2005 and 2004 average commodity prices by product before and after realized losses on risk management contracts.

	Year Ended December 31		
	2005	2004	Change
Light to medium oil ($ per bbl)	**$ 57.07**	$ 44.95	27%
Heavy oil ($ per bbl)	**$ 39.43**	$ 31.13	27%
Natural gas liquids ($ per bbl)	**$ 52.40**	$ 40.95	28%
Natural gas ($ per mcf)	**$ 9.05**	$ 6.32	43%
Average realized price ($ per BOE)	**$ 50.01**	$ 39.18	28%
Realized risk management losses ($ per BOE) (1)	**$ (5.94)**	$ (6.43)	(8%)
Net realized price ($ per BOE)	**$ 44.07**	$ 32.75	35%

(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 28% higher for the twelve months ended December 31, 2005 as compared to 2004. WTI for the same period increased by $15.16 per bbl or 37%. However, this increase was partially offset by a stronger Canadian dollar. The Canadian dollar increase in WTI was significantly lower at 27% which is consistent with the increase on our total realized prices per BOE of 28%.

For the latter half of 2005, our realized prices also reflected the change in our production mix. For the first seven months of the year approximately 45% of our production was priced off of the Bow River Stream, which is generally considered a medium oil stream, and approximately 11% was priced off the light oil benchmark, Edmonton Par. Subsequent to acquiring Hay River, our product pricing was more heavily weighted towards Edmonton Par at approximately 25% and less heavily weighted towards Bow River pricing at approximately 36%. This change has resulted in a higher overall realized price as the production from our Hay River property is sold through a light oil pipeline at a premium price relative to our other medium properties. Despite this change in product mix in 2005, we realized wider price differentials compared to benchmark prices than we did in 2004. This is due to a general widening of benchmark differentials for lower gravity crude oil in 2005 relative to 2004.

The impact of wider differentials was particularly evident in the realized prices for our light/medium production. The differential on our light/medium realizing prices relative to Edmonton Par widened in 2005 to 17.0% from 14.4% in 2004, despite our Hay River property realizing a higher price than our other medium gravity oil production. This widened price differential is primarily explained by the higher average Bow River differential to Edmonton Par of 36% compared to 29% in 2004. The remainder of the difference is due to the 7% higher weighting of medium oil production in 2005 than in 2004, which would result in an overall lower differential to Edmonton Par in 2004 than in 2005 for our light/medium oil.

Our average heavy oil price differential compared to Bow River narrowed from 16.3% in 2004 to 11.0% in 2005 as our realized sales prices relative to benchmarks has generally been higher in 2005, due to stronger market premiums for Bow River crude oil.

In 2005, heavy oil differentials narrowed between May and August and our heavy gravity crudes were positively impacted as a result. Towards the end of the third quarter and more significantly in the fourth quarter, heavy oil differentials widened and crude oil prices were somewhat lower. This was expected as heavy oil differentials usually widen in the fourth quarter due to seasonal demands. Edmonton Par decreased by 7% from the third quarter to the fourth quarter, while Bow River prices decreased by 22%.

Over the past 20 years the benchmark heavy differential has averaged very close to 29% of WTI. Due to the volatility in heavy oil differentials we have entered into differential hedges to partially shelter us from this volatility. Further discussion on these hedges is contained under the heading "Risk Management Contracts" of this MD&A.

Risk Management Contracts

All of our hedging activities are carried out pursuant to policies approved by the Board of Directors of Harvest Operations Corp. Management intends to facilitate stable, long-term monthly distributions by reducing the impact of volatility in commodity prices. As part of our risk management policy, management utilizes a variety of financial instruments to manage commodity price, heavy oil price differentials, foreign currency and interest rate exposures. These instruments are commonly referred to as 'hedges' but may not receive hedge treatment for accounting purposes. Management also enters into long-term, fixed price electricity purchase contracts to assist in maintaining stable operating costs. We reduce our exposure to credit risk associated with these financial instruments by only entering into transactions with financially sound, credit-worthy counterparties. Our risk management contracts at December 31, 2005 consist of indexed puts, participating swaps, collars, fixed price heavy oil differential and electricity price purchase contracts.

The table below provides a summary of net gains and losses on risk management contracts during 2005 and 2004:

($ thousands)	Year Ended December 31, 2005 Oil	Gas	Currency	Electricity	Total	Year Ended December 31, 2004 Total
Realized (losses) /gains on risk management contracts	**(80,677)**	**–**	**1,406**	**6,290**	**(72,981)**	(52,427)
Unrealized (losses)/ gains on risk management contracts	**(41,360)**	**378**	**(3,488)**	**8,389**	**(36,081)**	3,322
Amortization of deferred charges relating to risk management contracts	**(10,759)**	**–**	**–**	**–**	**(10,759)**	(14,946)
Amortization of deferred gains relating to risk management contracts	**–**	**–**	**–**	**1,779**	**1,779**	350
Total (losses)/gains on risk management contracts	**(132,796)**	**378**	**(2,082)**	**16,458**	**(118,042)**	(63,701)

Our total realized loss on oil price and foreign exchange risk management contracts increased to $79.3 million (or $5.94 per BOE) for the year ended December 31, 2005 compared to $54.5 million (or $6.43 per BOE) for the year ended December 31, 2004, due to the significant increases in commodity prices in 2005 compared to 2004 as well as higher volumes committed under risk management contracts. This loss effectively represents the cost of insurance to provide price protection from commodity price downturns. The decrease in the loss per BOE, despite higher commodity prices, is due to a change in our hedging strategy. This increase was slightly offset by gains on our currency exchange positions as the Canadian dollar traded below $1.20 per $1.00 U.S. in 2005, which enabled us to realize gains.

In the first half of 2005, a significant portion of our hedging contracts had fixed ceilings such that in an increasing pricing environment, our losses increased dollar for dollar as the WTI price increased. We have substantially changed our hedging strategy to provide firm floors with upside participation. Examples of such contracts include 'indexed puts' and 'participating swaps'. At December 31, 2005, all price contracts with fixed ceilings have expired. As a result, for the year ended December 31, 2006, our realized losses on our oil price risk management contracts will most likely be less than if we continued to use price contracts with fixed ceilings. The 2006 contracts also have higher average floor prices. Price contracts with fixed ceilings such as swaps and collars represented $3.56 per BOE (or $47.5 million) of the total realized loss of $5.94 per BOE (or $79.3 million) in 2005. The total loss on our indexed puts for the year ended December 31, 2005, was $37.0 million (or $2.78 per BOE).

Our realized losses on oil risk management contracts have been partially offset by gains on our heavy oil differential hedges. We have taken steps to mitigate the impact of wider differentials on a portion of our heavy crude oil by fixing the differentials as a percentage of WTI at an average 28% of WTI. These transactions became effective in July of 2005 on 10,000 bbls per day and extend through December of 2006. For the year ended December 31, 2005, these heavy oil differential hedges represented a gain of $0.29 per BOE or $3.9 million.

For the 2005 fiscal year, we did not hedge natural gas prices. Similar to WTI prices, natural gas prices rose consistently through 2005 from a low of $5.71 U.S./MMBtu on January 3, 2005 to a high of $15.78 U.S./MMBtu on December 13, 2005. In 2005, our natural gas was sold almost exclusively at a price that moves with the benchmark AECO "C" hub prices. In the fourth quarter of 2005, we entered into a natural gas collar on 5,000 GJ/day with a floor of $9.00/GJ and a ceiling of $13.06/GJ, that will provide us with price protection from April 2006 to October 2006.

We have also entered into risk management contracts which provide us protection on rising power costs. We have realized gains on these contracts of $6.3 million (or $0.47 per BOE). 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 year ended December 31, 2005 were $45.1 million or ($3.38 per BOE). For the year ended December 31, 2004, unrealized losses on risk management contracts were $11.3 million or $1.33 per BOE. As of October 1, 2004, we ceased to apply hedge accounting to our risk management contracts. As a result, from October 1, 2004, all of our hedging instruments are marked-to-market as at the balance sheet date with the resulting gain or loss reflected in earnings in the respective accounting period as an unrealized gain or loss on risk management contracts. The fair market valuation represents the amount that would be required to settle each contract on the period end date and is determined using prices from actively quoted markets.

Collectively, our risk management contracts had an unrealized mark-to-market deficiency of $52.6 million as at December 31, 2005. The difference between this value and the mark-to-market amount at December 31, 2004 ($15.4 million) is included in our unrealized loss in the twelve month period ended December 31, 2005. Please refer to Note 16 to the consolidated financial statements for further details of the financial instruments outstanding at December 31, 2005. Also included in our unrealized losses is the amortization of the deferred charges and credits that were deferred when we ceased to apply hedge accounting. This represented $9.0 million of our total unrealized gains and losses on risk management contracts for 2005 and $14.6 million for 2004. These amounts are discussed further under the heading "Deferred Charges and Credits".

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 full year 2005 and 2004, our net royalties as a percentage of revenue were 16.9%, which represented $113.0 million and $56.0 million, respectively. Increases in the royalty rate were expected due to the higher rates associated with the Hay River property acquired in August 2005, and a 3.6% surcharge on gross revenue applied by the Saskatchewan government on gross resource revenues earned in Saskatchewan (2% for production from wells drilled subsequent to October 2002). This is a result of a recent change in the Saskatchewan legislation whereby trusts become subject to the same surcharge that applies to corporations effective April 1, 2005. We estimate the blended rate applied to our Saskatchewan properties will be approximately 3.1% of Saskatchewan revenue which makes up approximately 20% of our total production prior to the Viking Arrangement. The expected increases in royalty rates were offset by royalty 'holidays' realized in Saskatchewan due to more drilling activity in 2005 than in 2004. In addition, we also benefited from higher Alberta Royalty Tax Credits than initially anticipated.

For 2006, we are anticipating our royalty rate as a percentage of net revenues to be approximately 19.5%, considering the addition of the Viking assets.

Operating Expense

	Year Ended December 31				
($ thousands)	**2005**	**Per BOE**	2004	Per BOE	Per BOE Change
Operating expense					
Power	**$ 39,452**	**$ 2.96**	$ 27,097	$ 3.20	(9%)
Workovers	**25,791**	**1.93**	10,581	1.25	54%
Repairs and maintenance	**10,478**	**0.79**	4,504	0.53	49%
Labour – internal	**7,631**	**0.57**	4,551	0.54	6%
Fuel	**6,451**	**0.48**	2,068	0.24	100%
Labour – external	**5,917**	**0.44**	1,407	0.17	159%
Land leases	**5,306**	**0.40**	2,827	0.33	21%
Other	**26,232**	**1.97**	20,407	2.41	(18%)
Total operating expense	**127,258**	**9.54**	73,442	8.67	10%
Realized gains on power risk management contracts	**(6,290)**	**(0.47)**	(2,061)	(0.24)	96%
Net operating expense	**$ 120,968**	**$ 9.07**	$ 71,381	$ 8.43	8%

Total operating expense increased by $53.8 million (or 73%) for the year ended December 31, 2005 compared to the prior year. Approximately $44.0 million of the increase for the year ended December 31, 2005 is due to increased activity associated with acquisitions made in 2004 and 2005. The remainder of the increase is attributed to fuel cost increases, and unprecedented demand for oilfield services leading to higher costs for well servicing, workovers and well maintenance. In addition, weather related delays in servicing negatively impacted production for the year resulting in lower relative production volumes. Overall, we expect to continue to see higher operating costs as a result of general cost pressures in the oil and natural gas industry. To help control operating expenses, a portion of our capital spending program is directed towards operating cost reduction initiatives such as water disposal, fluid handling and power reduction projects. We strive to minimize operating costs, which contributes to stronger netbacks, and can extend reserve life by making the extraction of reserves more economical later in the life of the property.

As noted, electricity costs represent a significant portion (approximately 31%) of our operating costs and with rising electricity prices, particularly in Alberta, our operating expenses can be significantly impacted. On average, our Alberta electricity costs per megawatt hour ("MWh") were 33% higher in 2005 than they were in 2004. These increases were offset by the impact of the 2004 and 2005 acquisitions, which included properties that have lower average per BOE power usage than the properties held prior to the acquisitions. Power prices skyrocketed to average $116/MWh in the fourth quarter of 2005, the highest average quarterly price since the fourth quarter of 2000. In 2005, the average price for the year was $70.35/MWh, the highest annual average since 2001. Our fixed price purchase contracts have enabled us to partially offset rising electricity costs. The following table details the power costs per BOE before and after the impact of our hedging program.

	Year Ended December 31		
($ per BOE)	**2005**	2004	Change
Power costs	**$ 2.96**	$ 3.20	(7%)
Realized gains on electricity risk management contracts	**(0.47)**	(0.24)	96%
Net power costs	**$ 2.49**	$ 2.96	(16%)

Approximately 79% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $49.15 per MWh through December 2006. Of our estimated 2007 and 2008 Alberta electricity usage, 61% 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 2005 and future periods that are dedicated to increasing our power efficiency.

	Year Ended December 31		
	2005	2004	Change
Alberta Power Pool electricity price ($ per MWh)	**$ 70.35**	$ 54.59	29%

Operating Netback

	Year Ended December 31		
Operating Netback (3) ($ per BOE)	**2005**	2004	Change
Revenues	**$ 50.01**	$ 39.18	28%
Realized loss on risk management contracts (1)	**(5.94)**	(6.43)	(8%)
Royalties	**(8.47)**	(6.61)	28%
As a percent of revenue	**16.9%**	16.9%	–
Operating expense (2)	**(9.07)**	(8.43)	7%
Operating netback (3)	**$ 26.53**	$ 17.71	56%

(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 $0.47 per BOE for the full year 2005 and $0.24 per BOE for the same period in 2004.

(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 $8.83 per BOE higher in 2005 than the prior year as a direct result of our recent acquisitions and events discussed above, with the single largest factor being higher commodity prices.

General and Administrative (G&A) Expense

($ thousands except per BOE)	2005	2004	Change
	Year Ended December 31		
Cash G&A [1]	$ 13,571	$ 7,345	85%
Unit based compensation expense			
Non-cash	16,302	9,535	70%
Cash	824	1,824	(55%)
Total G&A	$ 30,697	$ 18,704	64%
Cash G&A per BOE ($ per BOE)	1.02	0.87	17%

(1) Cash G&A excludes the impact of our unit based compensation expense.

On a year-over-year basis, Cash G&A increased by $6.2 million (or 85%) over 2004 due to higher staffing levels in 2005. The majority (approximately 62% or $8.5 million) of our 2005 Cash G&A expenses are related to salaries and other staffing costs while in 2004, these staffing costs were 63% or $4.6 million of our Cash G&A expenses. In the latter half of 2004, we made two significant acquisitions that increased our overall staffing levels. These higher staffing levels impacted the entire year in 2005 as compared to a partial year in 2004. In addition to higher staffing levels, we incurred the one time and recurring costs related to our New York Stock Exchange listing, as well as higher insurance costs, professional services fees and costs associated with the evaluation of potential acquisition opportunities.

In an effort to minimize dilution, our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. Our cash unit right compensation expense for the twelve months ended December 31, 2005 decreased by $1 million from the prior year. The timing of exercises for cash is not consistent from period to period. The increase in non-cash unit right compensation expense of $6.8 million for the twelve months ended December 31, 2005 is a result of a higher market price for our Trust Units. As our non-cash Unit Appreciation Rights ("UAR") expense is determined based on the difference between the exercise price and the market value of the vested UARs at the end of each reporting period, an increasing Unit price has a significant impact on our non-cash UAR expense.

In 2006, we expect total cash G&A expenses to average approximately $1.25 on a per BOE basis. Although we anticipate efficiencies from the Viking Arrangement to ultimately reduce G&A per BOE in the medium to longer-term, we expect some incremental costs associated with integration in the short-term. In addition, due to the immediate vesting of the rights and awards issued under our Unit based compensation plans as a result of the Arrangement with Viking, we will also realize large increases in our Unit based compensation expense in the first quarter of 2006.

Interest Expense

($ thousands)	Year Ended December 31 2005	2004 (restated)	Change
Interest on short-term debt	**$ 4,089**	$ 6,781	(40%)
Amortization of deferred charges – short-term debt	**2,498**	3,734	(33%)
Total interest on short-term debt	**6,587**	10,515	(37%)
Interest on long-term debt			
Senior notes	**23,952**	5,117	368%
Convertible debentures	**2,865**	5,248	(45%)
Bank loan	**651**	–	100%
Amortization of deferred charges – long-term debt	**2,356**	818	188%
Total interest on long-term debt	**29,824**	11,183	167%
Total interest expense	**$ 36,411**	$ 21,698	68%

Interest expense for the twelve months ended December 31, 2005 was $14.7 million higher than for the same period in the prior year primarily due to paying interest on the senior notes for a full year and lower interest on short-term debt due to a lower average short-term debt balance during the year than in the prior year.

Interest expense reflects the charges on our outstanding bank debt, convertible debentures and senior notes as well as amortization of related financing costs. Interest on our bank debt is levied at the prime rate plus 0 to 2.25% depending on our debt to Cash Flows ratio. We assumed approximately $100 million of bank debt on the merger with Viking which will increase future interest charges compared to the fourth quarter of 2005. However, we have also negotiated a new credit facility in February 2006 which has lower interest margins than our previous facility.

Our outstanding convertible debentures have fixed interest rates at 9% for the first series (issued in January 2004), 8% for the second series (issued in August 2004) and 6.5% for our third series (issued in August 2005). However, interest for the convertible debentures is reported based on the effective yield of the debt component of the convertible debentures. The large number of conversions of convertible debentures during 2005 were primarily the higher interest rate debentures and will result in lower interest charges for these remaining debentures in 2006 than in 2005. However, under the Viking Arrangement, we assumed Viking's 10.5% ($35 million) and 6.40% ($175 million) unsecured subordinated convertible debentures. The assumption of these convertible debentures will more than offset the 2005 reduction in interest charges. 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 in 2006 on the senior notes should remain relatively consistent with 2005 with any fluctuations being attributed to volatility in Canadian dollar to U.S. dollar exchange rates.

A portion of the total interest expense recorded is non-cash ($535,000 for 2005 and $100,000 for 2004) relates to 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.

Depletion, Depreciation and Accretion Expense

($ thousands except per BOE)	Year Ended December 31 2005	2004	Change
Depletion and depreciation	**$ 155,841**	$ 88,777	75%
Depletion of capitalized asset retirement costs	**14,345**	9,778	47%
Accretion on asset retirement obligation	**8,770**	4,221	108%
Total depletion, depreciation and accretion	**$ 178,956**	$ 102,776	74%
Per BOE ($ per BOE)	**$ 13.41**	$ 12.14	10%

Our overall depletion, depreciation and accretion (DD&A) rate per BOE for the year ended December 31, 2005 is higher compared to the same period in 2004 primarily due to incremental production from the acquisitions made in the latter half of 2004 and 2005. The higher DD&A rate reflects a slightly higher per Unit amortization charge from these acquisitions.

Foreign Exchange Gain

Foreign exchange gains and losses are attributable to the effect of 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 U.S. dollar deposits and cash balances. Our senior notes, which were issued in October 2004, reduce our net exposure to fluctuations in foreign exchange rates by offsetting the impact on net oil prices realized.

The largest portion of our foreign exchange gains and losses are directly related to our U.S. dollar denominated senior notes. In the year ended December 31, 2005, the Canadian dollar strengthened against the U.S. dollar, and we incurred unrealized gains on our senior notes of $9.7 million, which was partially offset by realized losses on U.S. dollar deposit and other U.S. denominated transactions. In the year ended December 31, 2004 we recorded a gain of $7.1 million, again largely related to the strengthening Canadian dollar from the time we issued the senior notes.

Deferred Charges and Credits

The deferred charges balance on the balance sheet is comprised of three main components: deferred financing charges, discount on senior notes and deferred charges related to the discontinuation of hedge accounting. The deferred financing charges relate primarily to the issuance of the senior notes, convertible debentures and bank debt and are amortized over the life of the corresponding debt. The following table provides a summary of the components of the deferred charges at year end 2005 as compared to 2004.

($ thousands)	As at December 31, 2005				As at December 31, 2004			
	On Discontinuation of Hedge Accounting	**Financing Costs**	**Discount on Senior Notes**	**Total**	On Discontinuation of Hedge Accounting	Financing Costs (restated)	Discount on Senior Notes	Total
Opening balance	**10,759**	**12,781**	**2,000**	**25,540**	–	1,989	–	1,989
Additions	**–**	**5,207**	**–**	**5,207**	25,705	20,971	2,075	48,751
Transferred to Unit issue costs on conversion of debentures	**–**	**(2,071)**	**–**	**–** **(2,071)**	–	(5,721)	–	– (5,721)
Amortization	**(10,759)**	**(4,853)**	**(296)**	**(15,908)**	(14,946)	(4,458)	(75)	(19,479)
Closing balance	**–**	**11,064**	**1,704**	**12,768**	10,759	12,781	2,000	25,540

We discontinued the use of hedge accounting for all of our risk management contracts effective October 1, 2004. For contracts where hedge accounting had previously been applied, a deferred charge and a deferred credit was recorded equal to the fair value of the contracts at the time hedge accounting was discontinued, and a corresponding amount was recorded as a risk management contracts asset or liability. The deferred amount is recognized in income in the period in which the underlying transaction is recognized.

The deferred credit balance relating to the discontinuation of hedge accounting at December 31, 2005 was $398,000 (2004 – $2.2 million). This amount will be fully amortized to income by the end of 2006. The deferred credit balance on the consolidated balance sheet also includes a leasehold improvement credit of ($991,000), 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. In June 2004, we completed a Plan of Arrangement with a public oil and natural gas company, and acquired certain oil and natural gas producing properties in North Central Alberta for total consideration of $192.2 million. This transaction has been accounted for using the purchase price method, and resulted in Harvest recording goodwill of $43.8 million in 2004. This 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. No goodwill was recorded in association with the Hay River acquisition in August 2005 as the fair value of assets acquired approximated the total consideration paid.

Future Income Tax

The future income tax liability reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of our corporate operating subsidiaries for financial reporting purposes and their corresponding income tax bases. Future income taxes arise, for example, as depletion and depreciation expense recorded against capital assets differs from claims under related tax pools. Future taxes also arise when tax pools associated with assets acquired are different from the purchase price recorded for accounting purposes. We recorded a future income tax recovery of $32.4 million for the year ended December 31, 2005, and a recovery of $10.4 million for the year ended December 31, 2004. The significant increase in the future income tax recovery for the year ended December 31, 2005, despite positive earnings before taxes in the period, is due to the earnings by flow through entities of the Trust. The corporate subsidiaries of the Trust recorded an accounting loss in 2005.

Asset Retirement Obligation (ARO)

Effective January 1, 2004, we adopted a new Canadian accounting standard for the Accounting for Asset Retirement Obligations. In connection with a property acquisition or development expenditure, we record the fair value of the ARO as a liability in the year in which an obligation to reclaim and restore the related asset is incurred. 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.

As part of our periodic review of the assumptions used to determine our ARO, we have revised our initial estimate to reflect changes in costs, the anticipated timing of expenditures, as well as changes in our credit standing and additional knowledge obtained from operating the properties for a longer period of time. As a result of this review, and property acquisitions and drilling activity in the year, our asset retirement obligation has increased by a net amount of $20.6 million in 2005 from the estimate in 2004.

Non-Controlling Interest

At December 31, 2005, we recorded a non-controlling interest amount on our consolidated balance sheet of $3.2 million. 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.

The total number of exchangeable shares converted in the year ended December 31, 2005 was 272,578, leaving a balance of 182,969 outstanding at December 31, 2005 compared to a balance of 455,547 at December 31, 2004. The exchange ratio at December 31, 2005 was 1:1.17475, which would result in an additional 214,943 Trust Units issued if all of the exchangeable shares were converted at the end of the year.

Under the Arrangement with Viking, exchangeable shareholders were able to convert their exchangeable shares of Harvest Operations into Trust Units. As a result, 156,011 exchangeable shares were tendered, resulting in approximately 26,902 exchangeable shares remaining. Subsequent to the year end, we intend to issue a redemption notice to the remaining exchangeable shareholders to fully redeem their outstanding shares by the end of the second quarter of 2006.

The total net income attributed to non-controlling interest holders for years ended December 31, 2005 and 2004 was $149,000 and $225,000, respectively.

Related Party Transactions

For the year ended December 31, 2004, the Trust had obligations under equity bridge notes issued by one of our directors and a corporation controlled by that director. The notes were repaid prior to December 31, 2004.

Liquidity and Capital Resources

At the end of 2004, Harvest had bank borrowings totaling $75.5 million and undrawn credit capacity of $249.5 million, both pursuant to a $325 million revolving credit facility maturing on June 1, 2005. During 2005, Harvest earned Cash Flows totaling $309.8 million and incurred capital expenditures of $120.5 million, leaving Cash Flows after capital expenditures of $189.3 million to fund distributions. In 2005, Harvest declared distributions totaling $153.5 million (excluding the $10.7 million special distribution settled with the issuance of Trust Units) representing 50% of our Cash Flows, resulting in $35.8 million available for general corporate purposes. However in 2005, Harvest's Unitholders elected to direct $36.2 million of distributions paid to the distribution reinvestment programs resulting in retained Cash Flows after this reinvestment of $72.0 million.

On August 2, 2005, we completed our acquisition of Hay River with total cash consideration of $237.8 million. To fund the closing of this acquisition, we initially drew the funds from our existing $400 million revolving credit facility and subsequently reduced our borrowings with $239.0 million of net proceeds raised with the issue of 6,505,600 Trust Units (gross proceeds of $175.0 million) and the issue of 75,000, 6.5% convertible extendible unsecured subordinated debentures (gross proceeds of $75.0 million).

The terms of the $400 million revolving credit facility in place during the 2005 year enabled funds to be borrowed, repaid and re-borrowed throughout the revolving period. This credit facility would have expired on July 31, 2006 but was extendable for an additional 364 day period on an annual basis with the consent of the lenders. If the term was not extended, the credit facilities would convert to a 366 day non-revolving term loan with no repayment due until August 2007. The facility was secured by a $750 million charge over all of the assets of our operating subsidiaries and a guarantee from Harvest Energy Trust. The credit agreement prescribes an applicable interest rate that floats with market conditions, includes a margin that fluctuates based on our bank debt to Cash Flows ratio (as defined in the credit agreement) and contains covenants including a borrowing base limitation and semi-annual borrowing base review.

The issuance of 2,428,606 Trust Units on the conversion of $53.8 million of principle amount convertible debentures further strengthened our balance sheet in 2005. This compares with 8,742,399 Trust Units issued on the conversion of $134.1 million of principle amount in 2004. This accelerated rate of converting debentures to Trust Units reflects the increases in the per Unit distributions as well as the capital appreciation of the Trust Units (closing price on the TSX of $37.19 at December 30, 2005 compared to $22.95 on December 31, 2004).

At the end of 2005, we had bank borrowings totaling $13.9 million, undrawn credit capacity of $386.1 million and a $400 million revolving credit facility maturing on July 31, 2006. At December 31, 2005, our total debt as a percentage of total capitalization was 35.8% (31.3% excluding the convertible debentures from total debt) while our total debt to our annualized Fourth Quarter Cash Flow ratio was .91 (.79 excluding the convertible debentures from total debt). We consider these financial metrics to be aligned with our industry peers in the conventional oil and natural gas royalty trust sector.

Subsequent to our Arrangement with Viking, our financial profile will not be materially changed from a financial ratio standpoint. However, the increased size of the combined entity will provide improved access to capital whether it be bank credit, term debt or equity. The combined entity will have a more balanced production profile and we plan to invest $250 million in the development of our existing asset base in 2006. Our intent is to substantially replace our annual production. See our 2006 Outlook for more complete guidance on future expectations.

Concurrent with the closing of our Arrangement with Viking, we closed a $750 million extendible three year revolving credit facility with improved borrowing margins and more flexible covenant based terms. This facility has been syndicated with five Canadian chartered banks and at this time, is being further marketed to additional lenders to broaden the base of lenders as well as increase the total credit facility to a target of $900 million.

We are currently rated by Standard & Poor's as a "B+" long-term credit and we are currently on "CreditWatch Positive" following the announcement of our Arrangement with V-king. Moody's Investors Service has maintained its "B2" corporate family rating on us. When they placed us on "CreditWatch Positive", Standard & Poor's recognized the improvement in our business profile as a consequence of the increase in proved reserves and production levels, as well as the improved internal replacement opportunities.

During 2005, our foreign ownership grew to approximately 40% by December 31, 2005. Contributing to this increase in foreign ownership was the listing of our Trust Units on the New York Stock Exchange ("NYSE") in July 2005. Relative to our 2005 average daily trading volume on the Toronto Stock Exchange ("TSX") of 220,000 Units per day, the NYSE daily trading volume averaged 230,000 Units per day. The Arrangement with Viking resulted in reducing our foreign ownership to approximately 30%, as Viking's foreign ownership was approximately 20% at the time of the merger. In 2006, we anticipate that the NYSE listing will continue to attract U.S. investors and that our percentage of foreign ownership will continue to increase as has been the trend for other interlisted energy trusts. This improved liquidity should further enhance the currency value of our Trust Units to the benefit of all Unitholders.

For 2006, we anticipate that we will continue to have adequate liquidity to fund our capital spending program and planned distributions of our Cash Flow. Harvest's historically higher Unitholder participation in our distribution reinvestment plan further provides us with opportunities to reinvest Cash Flow toward operating and capital spending or debt repayment.

Contractual Obligations and Commitments

			Maturity		
Annual Contractual Obligation ($ thousands)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	304,619	–	13,869	–	290,750
Interest on long-term debt [d]	133,647	23,590	46,198	45,793	18,066
Interest on convertible debentures [c]	15,151	3,159	6,317	2,987	2,688
Operating and premise leases	9,521	2,238	4,056	3,227	–
Capital commitments [e]	4,936	4,936	–	–	–
Asset retirement obligations [f]	372,464	4,300	13,208	5,361	349,595
Total	840,338	38,223	83,648	57,368	661,099

(a) As at December 31, 2005, we had entered into physical and financial contracts for production with average deliveries of approximately 24,990 barrels of oil equivalent per day in 2006 and 7,500 barrels per day in 2007. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 16 to the consolidated financial statements for further details.

(b) Assumes that the outstanding convertible debentures either convert at the holders' option or are redeemed for Units at our option.

(c) Assumes no conversions and redemption by Harvest for Units at the end of the second redemption period. Only cash commitments are presented.

(d) Assumes no change in bank debt from December 31, 2005 and a constant foreign exchange rate.

(e) Relates to drilling and seismic commitments.

(f) 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

	Year Ended December 31	
($ thousands)	**2005**	2004
Land and undeveloped lease rentals	**$ 1,838**	$ 825
Geological and geophysical	**285**	525
Drilling and completion	**80,170**	22,958
Well equipment, pipelines and facilities	**32,644**	13,945
Capitalized Cash G&A expenses	**3,830**	3,580
Furniture, leaseholds and office equipment	**1,741**	829
Total capital expenditures	**$ 120,508**	$ 42,662

Harvest incurred $120.5 million of expenditures to drill 94 gross wells in 2005 compared to $42.7 million and 31 gross wells in the prior year. The increase in activity reflects our increased focus on internally developed projects to exploit opportunities arising from our successful acquisitions, as well as significantly improved economics. The WTI benchmark price for crude oil averaged US$56.56 in 2005 compared to US$41.40 in 2004, a year-over-year increase of over 37%. Harvest's 2005 capital program was a $77.8 million increase over the prior year and resulted in the addition of 8.2 MMBOE to Harvest's Proved plus Probable reserves and a 2005 F&D cost, including adjustments for changes in future development capital, of $13.10 per BOE. This compares to 9.2 MMBOE added in 2004 at a cost of $4.15 per BOE. As well as reflecting the general cost pressures of western Canada's oil industry, our 2005 F&D costs are more comparable to the results of our 2003 capital program (F&D costs of $11.60 per BOE) than our 2004 F&D costs, which include a significant uplift for revisions of estimates.

In 2005, our activity was focused on our heavy oil operations at Suffield (26 gross wells) and East Hayter (16 gross wells) as well as light oil opportunities at Hazelwood in southeast Saskatchewan (15 gross wells). At Suffield, the 26 wells included 14 successful wells and one dry well from this ongoing exploitation of existing oil pools. In addition, two new pool discoveries at Suffield added 11 successful delineation and development horizontal wells. At Hayter, one vertical and 15 horizontal wells were drilled successfully extending the northwest and southeast oil field boundaries as part of a continuing program to fully develop the field. At Hazelwood, ongoing exploitation of the light oil Tilston play resulted in the drilling of one dry well and 18 successful horizontal wells. This included full development of a 2004 new pool discovery.

The following summarizes Harvest's participation in gross and net wells drilled during 2005:

	Total Wells		Successful Wells		Abandoned Wells	
Area	Gross	Net	Gross	Net	Gross	Net
Suffield	26	26	25	25	1	1
East Hayter	16	13	16	13	–	–
Hazelwood	19	19	18	18	1	1
Other Areas	33	25	30	24	3	3
Total	94	83	89	80	5	3

Distributions to Unitholders and Taxability

During 2005, we declared $3.20 per Trust Unit ($153.5 million, excluding the settlement of a special one-time Trust Unit distribution relating to undistributed 2004 taxable income of $10.7 million) to Unitholders. This represents an increase from the distribution level declared to Unitholders through 2004 of $2.40 per Trust Unit ($64.6 million). The aggregate of distributions declared reflects the increase in distributions on a per Trust Unit basis in 2005 as well as a greater number of Units outstanding following the August equity issue and the ongoing conversion of the 9%, 8% and 6.5% series of convertible debentures and the exchange of exchangeable shares. Retained Cash Flows will continue to be used to fund debt repayment, capital development investments and possible future acquisition opportunities.

($ thousands except per Trust Unit amounts)	Years Ended December 31 2005	2004	% Change
Distributions declared (1)	$ 153,494	$ 64,563	138%
Per Trust Unit	3.20	2.40	33%
Taxability of distributions (%)	100%	100%	–
Per Trust Unit	$ 3.20	$ 2.40	33%
Payout ratio (%)	50%	52%	(2%)

(1) Excludes $10.7 million special distribution

Of the total distribution amount paid in 2005, $36.2 million was reinvested by Unitholders through the issuance of 1.2 million Trust Units under the Distribution Reinvestment Plan ("DRIP") and the Premium Distribution™ Plan. This reflects an annual average of 24% participation under these Plans. However, the Premium component was launched in August 2005 and participation increased to approximately 40% for the latter part of 2005. Enrollment in either the Distribution Reinvestment or Premium Distribution™ component also enables Unitholders to make additional cash purchases of Trust Units directly from treasury through the Optional Trust Unit Purchase Plan. Both the DRIP Plan and Premium Distribution™ Plan reduce the net cash outlay we are required to make on a monthly basis. Management anticipates that for 2006, participation in the DRIP Plan will be approximately 40%, the same level as had been experienced since the introduction of the Premium Distribution™ Plan in August 2005.

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. Under the Trust indenture, an amount equal to all undistributed royalty, interest and dividend income together with taxable and non-taxable portions of any capital gains realized by the Trust in the year, net of deductible trust expenses, will be payable to the Unitholders. As such, it is unlikely that the Trust will pay income taxes. However, the Trust's wholly-owned corporate subsidiary is subject to large corporations tax. The large corporations tax is currently scheduled to be eliminated by 2008 with the rate reducing from 0.175% in 2005 to 0.125% in 2006.

OUTLOOK

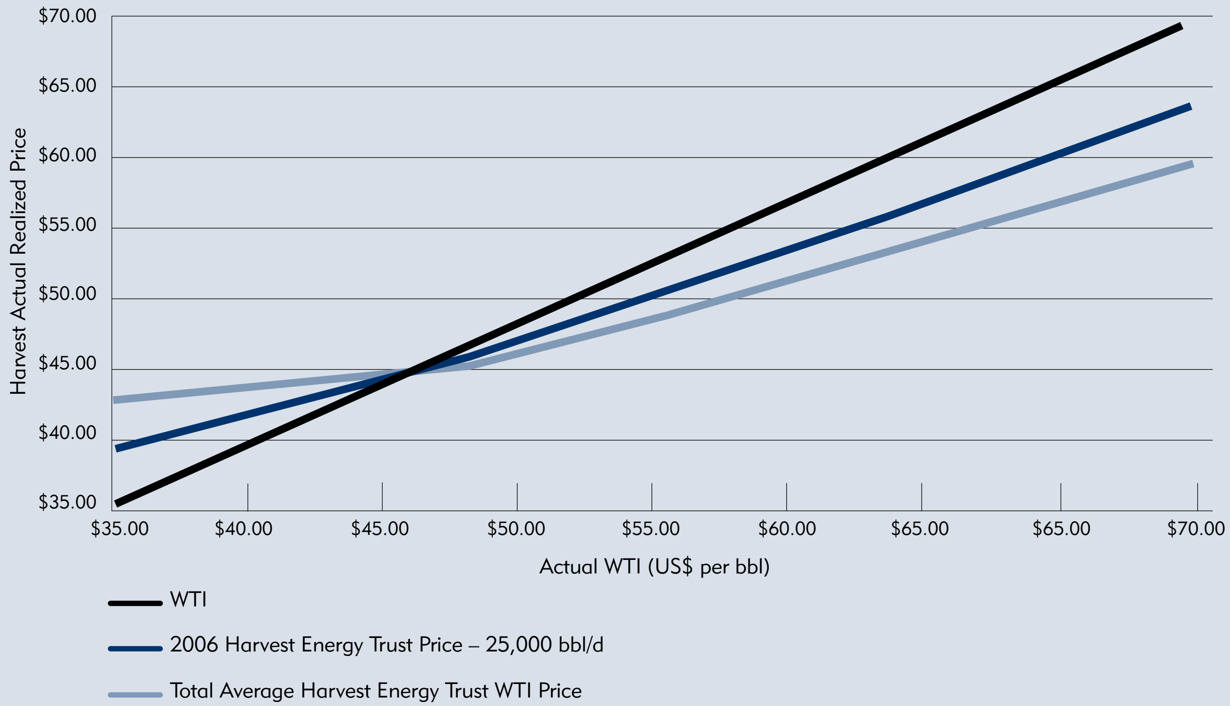
Following our merger with Viking, Harvest is an entity of roughly twice the size with some significant benefits of size but also with many of the same challenges. In 2006, we have significant balance sheet capacity with over $600 million of undrawn credit coupled with a market capitalization of approximately $3.5 billion. Since the completion of the merger, the daily trading volume in our Trust Units on the Toronto Stock Exchange (the "TSX") and the New York Stock Exchange (the "NYSE") totals approximately 1,000,000 Trust Units, representing over $30 million of daily liquidity. This liquidity along with our Trust Units being included in the S&P/TSX index enhances the attractiveness of our Trust Units to institutional investors which should improve the currency value of the Trust Units. A solid valuation is critical to our ability to compete for future acquisitions.

We anticipate that the market for Western Canadian petroleum and natural gas assets valued in the $150 million to $350 million range will continue to be in short supply and hotly contested with participation from a wide range of junior exploration and development companies, private equity capital as well as most other royalty trusts. However, we anticipate that while the more costly asset packages will also be in short supply, the competition will be significantly reduced to fewer corporations and a limited number of larger royalty trusts, such as Harvest. We will continue to be active in evaluating petroleum and natural gas acquisition opportunities which provide a large resource base, significant incremental development potential and access to an established processing and transportation infrastructure. We will likely finance the acquisition of such growth opportunities with some combination of our existing credit facilities along with the issue of longer term debt and Trust Units.

We intend to continue to be an active participant in the rationalization and consolidation of the Canadian royalty trust sector with an expectation of maintaining our current status as one of the largest trusts in our sector. The currency value of our Trust Units will be the fundamental determinant in the benefit of a trust-on-trust merger as these transactions are typically negotiated based on market valuations with premiums, if any, being nominal.

We view the sustainability of the royalty trust business model from both a financial and operational perspective. Over the long-term, our sustainability will be dependent on our ability to replace production with a capital spending program, as well as pay our distributions to Unitholders entirely from Cash Flows. Following our $120.5 million of capital spending while maintaining a 50% payout ratio in 2005, we are planning a $250 million capital program for 2006. The 2006 capital program is primarily an infill drilling program with significant activity planned for our Hay River, Markerville, Suffield and southeast Saskatchewan properties accounting for about 130 wells of an estimated 240 to 280 well program. With our existing production declining at an annual rate of about 20% (or 12,800 BOE per day per year on an estimated initial production base of 64,000 BOE per day), our 2006 capital program will target a success rate of $20,000 per flowing BOE per day. We anticipate that with our planned capital program, production for 2006 will be approximately 60,000 BOE/d.

Beyond 2006, Harvest currently anticipates that our production will continue to be 75% oil weighted, consistent with our 2006 capital spending plans. With our 2006 natural gas production estimated to be approximately 100,000 mcf per day (16,000 BOE per day) following the merger with Viking, our Cash Flows in 2006 will continue to be more sensitive to changes in the benchmark price for crude oil (WTI) and to a lesser extent, the heavy oil price differentials in western Canada than to changes in natural gas prices, although our natural gas prices are relatively unprotected. At the end of 2005, we had oil price risk management contracts in place in respect of approximately 25,000 bbls per day for 2006 and 17,500 bbls per day in 2007. The 2006 contracts provide downside protection should the WTI benchmark price drop below US$46.00. This protection is exchanged for reduced participation in upward price movement that exceeds US$46.00 on approximately 53% of expected oil production (67% of our expected production after deduction of the various royalty interests), while our 2007 contracts provide downside protection at US$55.00 with a reduced participation in prices that exceed US$55.00. At the end of 2005, our 2006 oil price risk management contracts had a mark-to-market deficiency of $66.0 million while the 2007 contracts had a deficiency of $10.4 million. The following chart reflects the weighted average price Harvest will receive for the approximately 25,000 bbls per day of oil price contracted for 2006 at various WTI oil prices:



In addition to our WTI price contracts, we have entered into heavy oil price differential contracts that fix the price differential at approximately 29% of the WTI benchmark price on 10,000 bbls per day in 2006. This represents approximately 55% of our expected heavy oil production for 2006, after adjusting for volumes added during blending. At the end of 2005, these contracts had a mark-to-market value of $14.1 million.

We anticipate that our 2006 operating costs will average approximately $10.00 per BOE, reflecting the industry wide cost pressures of 10% to 15%, offset by our fixed price power purchase contracts. For 2006, we have entered into fixed price power purchase contracts for approximately 45 MWh at an average cost of approximately $50.00 per MWh representing approximately 79% of our anticipated power purchase requirements. Compared to our 2005 operating cost of $9.07 per BOE ($9.54 excluding adjustments for the benefits of the fixed price power purchase contracts) our per BOE operating cost expectation for 2006 of approximately $10.00 is within industry expectations. For 2006, we anticipate our general and administrative costs will average about $1.25 per BOE before the charges for Unit based compensation expense and the one time charges relating to our Arrangement with Viking.

We have declared per Trust Unit distributions of $0.35 for January 2006 and $0.38 for February and March 2006, and provided commodity prices remain between US$55.00 to US$60.00 for the WTI benchmark oil price and $7.00 and $9.00 for the AECO benchmark price for Alberta natural gas, it is anticipated that distributions of $0.38 per trust unit for the balance of 2006 would reflect a payout ratio of approximately 70%. With anticipated 2006 capital spending of $250 million and monthly distributions of $0.38 per Trust Unit for the balance of the year, Cash Flows after distributions would be approximately $50 million short to fund the expected 2006 capital spending before considering the reinvestment of distributions by Unitholders. A participation level of approximately 25% by our Unitholders in our distribution reinvestment programs would be required to offset the shortfall compared to our current participation level of 40%.

The following table reflects sensitivities of Harvest's anticipated 2006 Cash Flow to key assumptions in our ongoing business.

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$ per bbl)	$ 58.00	$ 5.00	$ 0.55 / Unit
CAD/USD exchange rate	$ 0.87	$ 0.02	$ 0.12 / Unit
AECO daily natural gas price	$ 10.00	$ 2.00	$ 0.45 / Unit
Interest rate on outstanding bank debt	5.00%	1.0%	$ 0.01 / Unit
Liquids production volume (bbl/d)	44,500	2,000	$ 0.35 / Unit
Natural gas production volume (mcf per day)	92,000	5,000	$ 0.14 / Unit
Operating expenses (per BOE)	$ 10.00	$ 1.00	$ 0.21 / Unit

SUMMARY OF HISTORICAL ANNUAL RESULTS

	Years Ended December 31		
($ thousands except Trust Unit and per Trust Unit amounts)	**2005**	2004	2003
		(restated)	(restated)
Revenue, net of royalties	**554,494**	275,819	102,939
Cash Flows [1]	**309,843**	123,710	46,492
Per Trust Unit, basic [1]	**$ 6.66**	$ 4.94	$ 3.69
Per Trust Unit, fully diluted [1]	**$ 6.35**	$ 3.97	$ 3.58
Net income	**104,946**	11,241	14,646
Per Trust Unit, basic	**$ 2.25**	$ 0.45	$ 1.16
Per Trust Unit, fully diluted	**$ 2.19**	$ 0.43	$ 1.13
Total assets	**1,308,481**	1,050,483	256,440
Total long-term financial liabilities	**349,074**	326,250	25,000

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

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31		
	2005	2004	Change
FINANCIAL			
Revenues	**185,824**	128,907	44%
Royalties	**(31,178)**	(21,944)	42%
Realized losses on risk management contracts (3)	**(8,726)**	(16,116)	46%
Unrealized gains on risk management contracts	**28,463**	18,122	57%
Net revenues	**174,383**	108,969	60%
Operating expenses	**38,834**	25,725	51%
Realized gains on power hedge	**(4,507)**	(611)	638%
Net operating expenses	**34,327**	25,114	37%
General and administrative expenses	**5,651**	13,447	58%
Less: Unit based compensation expenses	**(1,568)**	(10,590)	85%
Total cash general and administrative expenses	**4,083**	2,857	43%
Interest expense	**8,499**	9,919	14%
Net income	**75,638**	11,600	552%
Payout ratio	**57%**	47%	10%
Capital asset additions (excluding acquisitions)	**39,476**	8,873	345%
OPERATING			
Daily sales volumes			
Light/medium oil (bbl/d)	**20,471**	16,004	28%
Heavy oil (bbl/d)	**13,273**	15,121	(12%)
Natural gas liquids (bbl/d)	**867**	1,310	(34%)
Natural gas (Mcf per day)	**25,339**	28,678	(12%)
	38,834	37,215	4%
OPERATING NETBACKS (1) ($ PER BOE)			
Revenue	**52.01**	37.65	38%
Realized loss on risk management contracts	**(3.70)**	(4.89)	(24%)
Royalties as a percent of revenue	**(8.73)**	(6.41)	36%
As a percent of revenue	**16.8%**	17.0%	–
Operating expense (2)	**(9.60)**	(7.34)	31%
Operating Netback (1)	**29.98**	19.01	58%

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

(2) Includes realized gain on electricity risk management contract of $1.26 per BOE and $0.18 per BOE for the three months ended December 31, 2005 and 2004 respectively.

(3) Includes gains on electricity risk management contracts of $4.5 million and $2.6 million for the three months ended December 31, 2005 and 2004.

Our 2005 fourth quarter revenues have increased over the fourth quarter in 2004 as a result of higher commodity prices and a change in product mix due to the acquisition of the Hay River property. Light/medium oil sales revenue for the three month period ended December 31, 2005 was $37.5 million (or 52%) higher than in same period in the prior year due to a favourable price variance of $17.7 million and a favourable volume variance of $19.8 million. Heavy oil revenues for the three months ended December 31, 2005 increased by $7.3 million (or 19%) due to a favourable price variance of $11.9 million and an unfavourable volume variance of $4.6 million. Natural gas sales revenue increased by $11.5 million (or 76%) for the three months ended December 31, 2005 over the same period in 2004, which reflects a favourable price variance of $13.2 million and an unfavourable volume variance of $1.7 million. The decrease in natural gas volumes in the fourth quarter of 2005 compared to the fourth quarter of 2004 reflects the natural declines in our natural gas properties.

Our fourth quarter 2005 production volumes are higher than in 2004 due to the impact of the Hay River acquisition made in the third quarter of 2005. Production in the fourth quarter of 2005 reflects a full quarter of production from Hay River as well as added production from our drilling activity in the year.

For the three months ended December 31, 2005, our net royalties as a percentage of revenue were 16.8% ($31.2 million), compared to 17.0% ($21.9 million) in the same period in 2004. The small decrease in the royalty rate in the fourth quarter of 2005 compared with the same period in 2004, considering the 37% increase in net prices and higher royalty rates for the Hay River property, is attributable to higher than expected Alberta Royalty Tax Credits recognized in the fourth quarter for drilling activity in the province during the year.

Operating expenses increased by $13.1 million (or 51%) for the three months ended December 31, 2005 compared to the same period in the prior year. The increase in fourth quarter costs in 2005 relative to 2004 reflects inflationary cost pressures in the Western Canadian oil and natural gas sector and power costs.

For the three months ended December 31, 2005, Cash G&A increased by $1.2 million (or 43%) compared to the same period in the prior year. This increase is reflective of additional staffing costs relating to the Hay River acquisition, business development costs and generally higher costs for our external service providers.

For the three months ended December 31, 2005, interest expense decreased by $1.4 million relative to the same period in the prior year due to lower average debt balances on the credit facility in 2005.

SUMMARY OF HISTORICAL QUARTERLY RESULTS

The table and discussion below highlight our performance for the previous eight quarters on select measures. Our Initial Public Offering took place in December of 2002.

(Restated-Refer to Note 3 of consolidated financial statements)

	2005				2004			
Financial	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenue, net of royalties	**$ 154,646**	**$ 169,654**	**$ 120,263**	**$ 109,931**	$ 106,964	$ 85,096	$ 44,461	$ 39,298
Net income (loss)	**75,638**	**52,862**	**19,516**	**(43,070)**	11,600	1,740	151	(2,250)
Per Trust Unit, basic (2)	**1.45**	**1.09**	**0.45**	**(1.02)**	0.29	0.06	0.01	(0.13)
Per Trust Unit, diluted (2)	**1.42**	**1.08**	**0.44**	**(1.02)**	0.27	0.06	0.01	(0.13)
Cash Flows (1)	**96,431**	**103,508**	**52,217**	**52,687**	52,870	41,267	15,839	13,734
Per Trust Unit, basic (1)	**1.84**	**2.14**	**1.32**	**1.25**	1.31	1.42	0.91	0.80
Trust Unit, diluted (1)	**1.81**	**2.09**	**1.29**	**1.19**	1.18	1.12	0.78	0.67
Distributions per Unit, declared	**1.05**	**0.95**	**0.60**	**0.60**	0.60	0.60	0.60	0.60
Total long-term financial liabilities	**349,074**	**386,124**	**455,163**	**321,534**	326,250	95,609	57,780	58,984
Total assets	**1,308,481**	**1,327,272**	**1,117,792**	**1,079,269**	1,050,459	1,070,016	488,204	260,658
Total production (BOE per day)	**38,834**	**37,549**	**34,463**	**35,386**	37,215	24,856	15,233	15,070

(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.

The above table highlights our performance over the fourth quarter of 2005, and the preceding seven quarters.

Net revenues and Cash Flows have increased steadily over the eight quarters shown as above. The significantly higher revenue and Cash Flows in the third quarter of 2005 relative to the second quarter of 2005 is primarily due to higher production from the Hay River acquisition, stronger crude oil prices and narrower heavy oil differentials early in the quarter. This trend did not continue into the fourth quarter of 2005 as a result of decreased commodity prices and widening heavy oil differentials. The most significant increases in revenue occurred through the second and third quarter of 2005, due to unprecedented commodity prices, and the third and fourth quarters of 2004, as a result of the two acquisitions completed in June and September of that year. The general increasing revenue trend since the fourth quarter of 2003 is also attributable to the strong commodity price environment through 2004 and 2005.

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 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 accounted for increased volatility in our 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.

Production increases in the latter half of 2005, despite natural declines reflect the addition of the Hay River property as well as added production from our drilling program.

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed is accumulated and communicated to our management as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have concluded, based on their evaluation as of the end of the period covered by the annual filings, that our disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information relating to the Trust and its consolidated subsidiaries, is made known to them by others within those entities. It should be noted that while the CEO and CFO believe that our disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

CRITICAL ACCOUNTING POLICIES

Oil and Natural Gas Accounting

In accounting for oil and natural gas activities, we can choose to account for our oil and natural gas activities using either the full cost or the successful efforts method of accounting.

We follow the Canadian Institute of Chartered Accountants guideline 16, "Oil and Gas Accounting – Full Cost" for the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. Any gains or losses on disposition of oil and natural gas properties are not recognized unless that disposition would alter the rate of depletion by 20% or more. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves before royalties as estimated by independent petroleum engineers.

The basis used for the calculation of the provision is the capitalized costs of petroleum and natural gas assets plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of oil. The reserve estimates used in these calculations can have a significant impact on net income, and any downward revision in this estimate could result in a higher depletion and depreciation expense. In addition, a downward revision of this reserve estimate could require an additional charge to income as a result of the computation of the prescribed ceiling test under this guideline. Under this method of accounting, an impairment test is applied to the overall carrying value of the capital assets for a Canada-wide cost centre with reserves valued at estimated future commodity prices at period end.

Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred and costs are generated on a property by property basis. Impairment is also determined on a property by property basis.

The difference between these two approaches is not expected to produce significantly different results for us, as our success rates for drilling activities are high. However, each policy is likely to generate a different carrying value of capital assets and different net income.

Critical Accounting Estimates

There are a number of critical estimates underlying the accounting policies applied when preparing the consolidated financial statements due to timing differences between when certain activities take place and when these activities are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

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

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

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

The estimates in reserves impact many of our accounting estimates including our depletion calculation. A decrease of reserves by 10% would result in an increase of approximately $18 million in our depletion expense.

Asset Retirement Obligations

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

Impairment of Capital Assets

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

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

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

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

Any impairment charges would reduce our net income.

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

IMPACT ON NET INCOME OF CHANGE IN ACCOUNTING POLICIES

The implementation of new accounting policies in 2005 as discussed below resulted in changes to the accounting treatment for exchangeable shares, convertible debentures and the equity bridge notes. As a result, we have restated previously reported annual and quarterly net income. The restatements were required per the transitional provisions of the respective accounting standards.

The following table illustrates the impact of the new accounting policies on quarterly net income (loss) and net income (loss) per Unit for periods which have been presented for comparative purposes:

	2004			
($ thousands)	Q4	Q3	Q2	Q1
Net Income (loss) before change in accounting policies (1)	12,536	5,166	1,594	(1,065)
Decrease in net income				
Interest expense (2)	(751)	(3,386)	(1,443)	(1,185)
Non-controlling interest (3)	(185)	(40)	–	–
Net income (loss) after change in accounting policies	11,600	1,740	151	(2,250)
Net income (loss) per Trust Unit, as reported				
Basic	0.29	0.07	0.02	(0.06)
Diluted	0.28	0.07	0.02	(0.06)
Net income (loss) per Trust Unit, as restated				
Basic	0.29	0.06	0.01	(0.13)
Diluted	0.27	0.06	0.01	(0.13)

(1) This represents net income as reported before retroactive restatement for changes in accounting policies.

(2) Adoption of the amendment to CICA Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" resulted in the convertible debentures and equity bridge notes being classified as debt whereas previously they were classified as equity. In addition, the interest expense relating to these instruments was required to be charged against net income rather than directly to accumulated income. Also, the deferred financing charges associated with the convertible debentures are now reflected separately in deferred charges on the balance sheet and amortized to income over the term of the debt; previously they were applied as a reduction to the outstanding balance.

(3) Adoption of EIC 151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts", resulted in the exchangeable shares being classified as minority interest and the income attributed to minority interest holders being applied against net income.

CHANGES IN ACCOUNTING POLICY

Financial Instruments

On January 1, 2005, the Trust retroactively adopted the amendment to the Canadian Institute of Chartered Accountants ("CICA") handbook section 3860 "Financial Instruments". These changes require that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as liabilities. The convertible debentures and the equity bridge notes previously issued by the Trust have characteristics that meet the noted criteria and we have retroactively accounted for these instruments as debt and reflected related interest costs as interest expense in the statement of income.

Exchangeable Shares

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be non-transferable in order to be classified as equity. The exchangeable shares issued by Harvest Operations are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheet. In addition, a portion of consolidated income or loss before non-controlling interest is reflected as a reduction to such income or loss in the Trust's consolidated statement of income. Prior periods have been retroactively restated.

Variable Interest Entities ("VIEs")

In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" ("AcG-15"). AcG-15 defines VIEs as entities in which either: the equity at risk is not sufficient to permit that entity to finance its activities without additional financial support from other parties; or equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. AcG-15 harmonizes Canadian and U.S. GAAP and provides guidance for companies consolidating VIEs in which it is the primary beneficiary. The guideline is effective for all annual and interim periods beginning on or after November 1, 2004. We have performed a review of entities in which the Trust has an interest and have determined that we do not have any variable interest entities at this time.

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 is permitted as of the beginning of a period beginning on or after July 1, 2005. We do not expect the adoption of this section will have a material impact on our results of operations or financial position.

OPERATIONAL AND OTHER BUSINESS RISKS

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

Operation of oil and natural gas properties:

- Applying a proactive management approach to our properties;
- Selectively adding skilled and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and
- Remunerating employees with a combination of average industry salary and benefits combined with a merit based bonus plan to reward success in execution of our business plan.

Estimates of the quantity of recoverable reserves:

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

Commodity price exposures:

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

Financial risk:

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

Environmental, health and safety risks:

- Adhering to our safety program and keeping abreast of current industry practices; and
- Committing funds on an ongoing basis, toward the remediation of potential environmental issues.

Changing government policy, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry:

- Retaining an experienced, diverse and actively involved Board of Directors to ensure good corporate governance; and
- Engaging technical specialists when necessary to advise and assist with the implementation of policies and procedures to assist in dealing with the changing regulatory environment.

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 Flows as cash flow from operating activities before changes in non-cash working capital and settlement of asset retirement obligations. Cash Flows 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 Flows 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 Flows. 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 twelve months ended December 31, 2005 and 2004, Cash Flows are reconciled to its closest GAAP measure, Cash Flows from operating activities, as follows:

	Three Months Ended December 31		Years Ended December 31	
($ thousands)	**2005**	2004	**2005**	2004
Cash Flows	**$ 96,431**	$ 52,870	**$ 309,843**	$ 123,710
Settlement of asset retirement obligations	**(1,813)**	(622)	**(4,146)**	(929)
Changes in non-cash working capital	**3,348**	(230)	**(22,519)**	(11,103)
Cash Flow from operating activities	**$ 97,966**	$ 52,018	**$ 283,178**	$ 111,678

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the year ended December 31, 2005 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 we consider such information reasonable, at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances or estimates or opinions change. 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.

MANAGEMENT'S REPORT TO UNITHOLDERS

Management is responsible for the integrity and objectivity of the information contained in this Annual Report and for the consistency between the financial statements and other financial reporting data contained elsewhere in the report. The accompanying consolidated financial statements of Harvest Energy Trust have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgment, particularly in those circumstances where the transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and reflect fairly the Trust's financial position, results of operations and cash flow within reasonable limits of materiality and within the framework of the accounting policies as outlined in the notes to the financial statements.

Management has established and maintains a system of internal controls to provide reasonable assurance that Harvest Energy Trust's assets are safeguarded from loss and unauthorized use, and that the financial information is reliable and accurate.

External auditors have examined the consolidated financial statements. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported operating results and financial condition of Harvest Energy Trust. The external auditors have unlimited and unrestricted access to the Audit Committee.

The Audit Committee of Harvest's Board of Directors comprised of non-management directors, has reviewed in detail the consolidated financial statements with management and the external auditors. The Audit Committee acts on behalf of the Board of Directors to ensure that management fulfills its financial reporting and internal control responsibilities. The Audit Committee is responsible for meeting regularly with management, and the external auditors to discuss internal controls over financial reporting process, auditing matters and various aspects of financial reporting. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

(signed) "John Zahary"

John Zahary
President & Chief Executive Officer

(signed) "Bob Fotheringham"

Bob Fotheringham
Vice President, Finance & Chief Financial Officer

March 8, 2006

AUDITORS' REPORT

TO THE UNITHOLDERS OF HARVEST ENERGY TRUST

We have audited the consolidated balance sheets of Harvest Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income and accumulated income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free from material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed) "KPMG LLP"

KPMG LLP
Chartered Accountants
Calgary, Canada

March 8, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands of Canadian dollars)	2005	(restated, Note 3) 2004
ASSETS		
Current assets		
Accounts receivable	$ 73,766	$ 44,028
Fair value of risk management contracts [Note 16]	21,231	8,861
Prepaid expenses and deposits	1,126	3,014
Future income tax [Note 15]	22,975	3,101
	119,098	59,004
Deferred charges [Note 6]	12,768	25,540
Fair value of risk management contracts [Note 16]	2,628	3,710
Capital assets [Notes 4 and 5]	1,130,155	918,397
Goodwill [Note 4]	43,832	43,832
	$ 1,308,481	$ 1,050,483
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities [Note 7]	$ 99,576	$ 76,251
Cash distribution payable	18,544	8,358
Fair value deficiency of risk management contracts [Note 16]	65,968	27,927
Bank loan	–	75,519
	184,088	188,055
Bank loan [Note 9]	13,869	–
Deferred credit	1,389	2,177
Fair value deficiency of risk management contracts [Note 16]	10,449	–
Convertible debentures [Notes 3 and 10]	44,455	25,750
7 7/8% Senior notes [Note 11]	290,750	300,500
Asset retirement obligation [Note 8]	110,693	90,085
Future income tax [Note 15]	25,275	37,772
Non-controlling interest [Notes 3 and 14]	3,179	6,895
Unitholders' equity		
Unitholders' capital [Note 12]	747,312	465,524
Equity component of convertible debentures [Notes 3 and 10]	2,639	116
Accumulated income	135,665	30,719
Accumulated cash distributions	(261,282)	(97,110)
	624,334	399,249
	$ 1,308,481	$ 1,050,483

Commitments, contingencies and guarantees [Note 19]
Subsequent events [Note 21]
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
Hector J. McFadyen
Director

((signed))
Verne G. Johnson
Director

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME

For the Years Ended December 31 (thousands of Canadian dollars, except per Trust Unit amounts)	2005	(restated, Note 3) 2004
Revenue		
Petroleum and natural gas sales	$ 667,496	$ 331,809
Royalty expense	(113,002)	(55,990)
Risk management contracts		
Realized net losses	(72,981)	(52,427)
Unrealized net losses	(45,061)	(11,274)
	436,452	212,118
Expenses		
Operating	127,258	73,442
General and administrative [Note 13]	30,697	18,704
Interest and other financing charges on short-term debt	6,587	10,515
Interest and other financing charges on long-term debt	29,824	11,183
Depletion, depreciation and accretion	178,956	102,776
Foreign exchange gain	(9,728)	(7,111)
Large corporations tax and other tax	134	1,505
Future income tax recovery [Note 15]	(32,371)	(10,362)
Non-controlling interest [Notes 3 and 14]	149	225
	331,506	200,877
Net income for the year	104,946	11,241
Accumulated income, beginning of year	30,719	19,478
Accumulated income, end of year	$ 135,665	$ 30,719
Net income per trust unit, basic [Note 12]	$ 2.25	$ 0.45
Net income per trust unit, diluted [Note 12]	$ 2.19	$ 0.43

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF ACCUMULATED DISTRIBUTIONS

For the Years Ended December 31, (thousands of Canadian dollars, except per Trust Unit amounts)	2005	(restated, Note 3) 2004
Accumulated distributions, beginning of year	$ 97,110	$ 32,547
Distributions	164,172	64,563
Accumulated distributions, end of year	$ 261,282	$ 97,110

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 (thousands of Canadian dollars)	2005	(restated, Note 3) 2004
Cash provided by (used in)		
Operating Activities		
Net income for the year	$ 104,946	$ 11,241
Items not requiring cash		
Depletion, depreciation and accretion	178,956	102,776
Unrealized foreign exchange gain	(8,588)	(5,537)
Amortization of deferred finance charges	4,853	4,458
Unrealized loss on risk management contracts [Note 16]	45,061	11,274
Non-cash interest expense	535	100
Future income tax recovery	(32,371)	(10,362)
Non-controlling interest	149	225
Unit based compensation expense	16,302	9,535
Settlement of asset retirement obligations	(4,146)	(929)
Change in non-cash working capital [Note 18]	(22,519)	(11,103)
	283,178	111,678
Financing Activities		
Issue of Trust Units, net of issue costs	167,256	164,743
Issue of equity bridge notes [Note 17]	–	30,000
Repayment of equity bridge notes [Note 17]	–	(55,000)
Issue of convertible debentures, net of issue costs [Note 10]	71,777	152,799
Issue of senior notes	–	311,951
Repayment of bank loan, net	(61,650)	(44,661)
Financing costs	(2,196)	(13,770)
Cash distributions	(107,091)	(47,074)
Change in non-cash working capital [Note 18]	(1,035)	5,097
	67,061	504,085
Investing Activities		
Additions to capital assets	(120,508)	(42,662)
Corporate acquisitions	(237,783)	(75,783)
Property acquisitions	(4,052)	(513,865)
Property disposition	2,177	–
Change in non-cash working capital [Note 18]	9,927	16,547
	(350,239)	(615,763)
Change in cash position	–	–
Cash position, beginning of year	–	–
Cash position, end of year	$ –	$ –
Interest paid	$ 30,771	$ 5,521
Large corporation tax and other tax paid	$ 2,079	$ 2,298

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

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

1. STRUCTURE OF THE TRUST

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 and is governed pursuant to the Amended and Restated Trust Indenture dated May 4, 2005 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its Trust Units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and to comply with the mutual fund trust requirements of the Income Tax Act (Canada). The Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as the bank debt and the $7^{7/8}$% senior notes.

The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural properties exceed 99% of certain deductible expenditures. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

References to "Harvest" refers to the Trust on a consolidated basis.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("U.S. GAAP") and to the extent that the differences materially affect the Trust, they are described in Note 20.

(a) Consolidation

These consolidated financial statements include the accounts of the Trust and its subsidiaries. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Use of Estimates

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. Specifically, amounts recorded for depletion, depreciation and accretion expense, asset retirement obligations and amounts used in the impairment tests for goodwill and capital assets are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) Revenue Recognition

Revenues associated with the sale of crude petroleum, natural gas and natural gas liquids are recognized when title passes to customers.

(d) Joint Venture and Partnership Accounting

The subsidiaries of the Trust conduct substantially all of their petroleum and natural gas production activities through joint ventures and through partnerships. The consolidated financial statements reflect only the Trust's proportionate interest in such activities.

(e) Capital Assets

Petroleum and Natural Gas Activities

The Trust follows the full cost method of accounting for its petroleum and natural gas activities. All costs of acquiring petroleum and natural gas properties, whether productive or unproductive, related development costs, and overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repair costs that do not extend or enhance the recoverable reserves are charged against income.

Proceeds from the sale of petroleum and natural gas properties are applied against capital costs. Gains and losses are not recognized on the disposition of petroleum and natural gas properties unless that disposition would alter the rate of depletion and depreciation by 20% or more.

Provision for depletion and depreciation of petroleum and natural gas assets is calculated using the unit-of-production method, based on proved reserves net of royalties as evaluated by independent petroleum engineers. The cost basis used for the depletion and depreciation provision is the capitalized costs of petroleum and natural gas assets, less the cost of unproved properties plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent Units on the basis of six thousand cubic feet of natural gas to one barrel of petroleum, reflecting the approximate relative energy content.

The Trust places a limit on the aggregate carrying value of capital assets associated with petroleum and natural gas activities which may be amortized to depletion and depreciation in future periods. Impairment is recognized when the carrying amount of the capital assets exceeds the sum of the undiscounted future cash flows expected from the proved reserves.

Upon recognition of impairment, Harvest would then measure the amount of impairment by comparing the carrying amounts of the capital assets to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves using Harvest's risk-free discount rate. Any excess carrying value above the net present value of the Trust's future cash flows would be a permanent impairment and reflected as a charge to net income for the period.

Cash flows are calculated based on future price estimates, adjusted for Harvest's contractual arrangements related to pricing and quality differentials.

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test.

Office Furniture and Equipment

Depreciation and amortization of office furniture and equipment is provided for on a straight line basis at rates ranging from 10% to 50% per annum.

(f) Goodwill

For accounting purposes goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The carrying value of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. Impairment is verified by comparing the carrying amount of goodwill for the reporting entity to the excess of the Trust's fair value of its publicly traded trust units over the related book value. If the fair value of Harvest's equity is less than the book value, impairment is measured by allocating the fair value of Harvest to its identifiable assets and liabilities at their fair values. The excess of this allocation represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized through the statement of income as an impairment. Impairment is charged to income in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized.

(g) Asset Retirement Obligations

Harvest recognizes the fair value of any asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and normal use of the assets. Harvest uses a credit-adjusted risk free discount rate to estimate this fair value. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using the method described under "Capital Assets". Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each subsequent period to reflect the passage of time and changes in the timing and amount of estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(h) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries make provisions for future income taxes.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs.

(i) Unit-Based Compensation

Harvest determines compensation expense for the Trust Unit Rights Incentive Plan ("Trust Unit Incentive Plan") and the Unit Award Incentive Plan by estimating the intrinsic value of the rights at each period end and recognizing the amount in income over the vesting period. After the rights have vested, further changes in the intrinsic value are recognized in income in the period of change.

The intrinsic value is the difference between the market value of the Units and the exercise price of the right in the case of the Trust Unit Incentive Plan, and the market value of the Units in the case of the Unit Award Incentive Plan. Under the Trust Unit Incentive Plan, the intrinsic value method is used as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment or Trust Unit equivalent, equal to the excess of the market value of the Units over the exercise price.

(j) Non-Controlling Interest

Non-controlling interest represents the exchangeable shares issued by Harvest Operations to third parties which are ultimately only exchangeable for Units of the Trust. These exchangeable shares were issued as partial consideration for a corporate acquisition during the year ended December 31, 2004. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares on issuance together with a portion of the Trust's accumulated earnings or loss attributable to the non-controlling interest subsequent to their issuance. Net income or loss is reduced for the portion of earnings or losses attributable to the non-controlling interest. As the exchangeable shares are converted to Trust Units, the non-controlling interest on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in Unitholders' capital.

(k) Deferred Financing Charges

Deferred financing charges relate to costs incurred on the issuance of bank loans, 7 7/8% senior notes and the convertible debentures and are amortized, on a straight-line basis over the term of the related debt, to interest expense.

(l) Financial Instruments

(i) Risk Management Contracts

The Trust is exposed to market risks resulting from fluctuations in commodity prices and currency exchange rates in the normal course of its business. The Trust may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, Harvest accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in income as an unrealized gain or loss on risk management contracts. Where Harvest has a physical commodity sales contract, it is also recorded at fair value. Fair values of financial instruments are determined from third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in income in the period they occur.

The Trust may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. At December 31, 2005 and 2004, the Trust had not designated any of its outstanding financial instruments as hedges.

(ii) Convertible Debentures

The Trust presents outstanding convertible debentures in their debt and equity component parts on the balance sheet.

The debt component represents the total discounted present value of the semi-annual interest obligations to be satisfied by cash and the principal payment due at maturity, using the rate of interest that would have been applicable to a non-convertible debt instrument of comparable term and risk at the date of issue. Typically, this results in an accounting value assigned to the debt component of the convertible debentures which is less than the principal amount due at maturity. The debt component presented on the balance sheet increased over the term of the relevant debenture to the full face value of the outstanding debentures at maturity. The difference is reflected as increased interest expense with the result that adjusted interest expense reflects the effective yield of the debt component of the convertible debentures.

The equity component of the convertible debentures is presented under "Unitholders' Equity" in the consolidated balance sheets. The equity component represents the value ascribed to the conversion right granted to the holder, which remains a fixed amount over the term of the related debentures. Upon conversion of the debentures into Units by the holders, a proportionate amount of both the debt and equity components are transferred to Unitholders' capital.

(iii) Equity Bridge Notes

Interest expense incurred in 2004 related to equity bridge notes, which were settled during the year ended December 31, 2004, has been recorded in interest and other financing charges on short-term debt in the statement of income in 2004.

(m) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses denominated in a foreign currency are translated at the monthly average rate of exchange. Translation gains and losses are included in income in the period in which they arise.

3. CHANGES IN ACCOUNTING POLICY

(a) Financial Instruments

Effective January 1, 2005, Harvest retroactively adopted the revised Canadian accounting standard for “Financial instruments that may be settled at the Issuers’ option in cash or its own equity instruments”, which requires that fixed amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as liabilities. This revised accounting standard applies to Harvest’s convertible debentures as well as its equity bridge notes. The retroactive application of this revised accounting standard impacts Harvest’s financial position and results from operations as reported in its 2004 audited financial statements. These changes in accounting policy do not impact the accumulated income for the period prior to 2004.

Convertible Debentures

This revised standard applies to Harvest’s 9% convertible debentures issued on January 29, 2004, its 8% convertible debentures issued on August 10, 2004 and the 6.5% convertible debentures issued on August 2, 2005 and requires such financial instruments to be classified as a liability with the related interest charged to income as incurred and issue costs amortized over the term of related security. In addition, a portion of the convertible debentures relating to its equity conversion feature is classified as an equity component resulting in the carrying value of the convertible debentures being less than their face value. This discount will be accreted over the term of the respective convertible debentures using the effective interest rate method. Upon conversion of the convertible debentures into Trust Units, the debt and equity component of the convertible debentures is reclassified to Unitholders’ Capital.

Previously, Unitholders’ equity had been credited with the full amount of the proceeds from the issuance of convertible debentures, net of issue costs, and the interest charged directly to the accumulated income as paid.

Equity Bridge Notes

Under the terms of the equity bridge notes, the interest and principal may have been repaid, at the option of the Trust, in Trust Units [Note 17]. The number of Trust Units issued would have been dependent on the market value of the Units at the time of issue. Accordingly, the revised standard requires the interest to be presented as a charge to income and the principal owing as a debt instrument. Previously, the interest had been presented as a reduction of accumulated income and the principal owing as an equity instrument.

(b) Exchangeable Shares

On January 19, 2005, a new pronouncement was issued relating to exchangeable securities issued by subsidiaries of income trusts that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. The interpretation requires that the shares be non-transferable in order to be classified as equity. The exchangeable shares issued by Harvest Operations are transferable and have been reclassified to non-controlling interest on the consolidated balance sheets. In addition, a provision for non-controlling interest is reflected in the consolidated statements of income. Prior periods have been retroactively restated to reflect this presentation.

The following tables reflect the changes resulting from the retroactive adoption of these accounting policy changes in 2004.

Impact of Changes in Accounting Policy

Balance sheet	As Reported December 31, 2004	Financial Instruments	Exchangeable Shares	As Restated December 31, 2004
Deferred charges	$ 24,507	$ 1,033	$ –	$ 25,540
Convertible debentures – debt	–	25,750	–	25,750
Non-controlling interest	–	–	6,895	6,895
Unitholders' capital	465,131	335	58	465,524
Exchangeable shares	6,728	–	(6,728)	–
Convertible debentures – equity	24,696	(24,580)	–	116
Accumulated income	31,416	(472)	(225)	30,719

Net income	Year Ended December 31, 2004
Net income – as previously reported	$ 18,231
Less: amortization of convertible debenture issue costs[a]	(447)
Less: interest on equity bridge notes[a]	(1,070)
Less: interest on convertible debentures[a]	(5,248)
Less: non-controlling interest[b]	(225)
Net income – as restated	$ 11,241

Income per Unit	Year Ended December 31, 2004
Basic as previously reported	$ 0.47
Basic as restated	0.45
Diluted as previously reported	0.45
Diluted as restated	0.43

4. ACQUISITIONS

(a) Business Acquisitions

On August 2, 2005, the Trust acquired a partnership with certain petroleum and natural gas producing properties for total cash consideration of $237.8 million. The results have been included in the consolidated financial statements as of the closing date.

This transaction was accounted for using the purchase method. The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition.

	Amount
Allocation of purchase price:	
Working capital deficiency	$ (2,644)
Capital assets	244,995
Asset retirement obligation	(4,568)
Total cash consideration	$ 237,783

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

On June 30, 2004, the Trust completed a Plan of Arrangement with a public oil and natural gas company to acquire all of its issued and outstanding shares. Under this plan, the Trust acquired certain petroleum and natural gas producing properties for total consideration of approximately $192.2 million. This amount consisted of the issuance of 2,720,837 Trust Units [Note 12] and the issuance of 600,587 exchangeable shares each at $14.77 [Note 14], $75 million in cash, acquisition costs of $0.8 million and the assumption of approximately $67.3 million in debt and working capital deficiency. The results have been included in the consolidated financial statements as of the closing date.

This transaction has been accounted for using the purchase price method. The following summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition.

	Amount
Allocation of purchase price:	
Working capital deficiency	$ (10,488)
Bank debt	(56,831)
Capital assets	213,455
Fair value of petroleum price risk management contracts	863
Goodwill	43,832
Asset retirement obligation	(8,353)
Future income tax	(57,642)
	$ 124,836
Consideration for the acquisition:	
Cash	$ 75,000
Issuance of Trust Units	40,183
Issuance of exchangeable shares	8,870
Acquisition costs	783
	$ 124,836

(b) Asset Acquisitions

On September 2, 2004, the Trust purchased petroleum and natural gas producing properties for cash consideration of approximately $511.4 million (including purchase price adjustments) and acquisition costs of $2.6 million. In association with this purchase, an asset retirement obligation of $45.1 million was recorded. The results have been included in the consolidated financial statements as of the closing date.

	Amount
Allocation of purchase price:	
Capital assets	$ 556,548
Asset retirement obligation	(45,134)
Cash	$ 511,414

In addition, for the year ended December 31, 2004 Harvest acquired $2.5 million of small property acquisitions.

5. CAPITAL ASSETS

December 31, 2005	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 1,135,118	$ (247,652)	$ 887,466
Production facilities and equipment	298,166	(59,732)	238,434
Office furniture and equipment	5,377	(1,122)	4,255
Total	$ 1,438,661	$ (308,506)	$ 1,130,155

December 31, 2004	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 845,396	$ (110,077)	$ 735,319
Production facilities and equipment	209,984	(27,817)	182,167
Office furniture and equipment	1,337	(426)	911
Total	$ 1,056,717	$ (138,320)	$ 918,397

General and administrative costs of $7.1 million (2004 – $3.6 million) have been capitalized during the year ended December 31, 2005, of which $3.7 million (2004– $nil) relate to the Trust Unit incentive plan and the Unit award incentive plan.

All costs, except those associated with undeveloped properties, are subject to depletion and depreciation at December 31, 2005 including future development costs of $183.5 million (2004 – $83.3 million). $12 million (2004 – $28.6 million) of undeveloped properties were excluded from the asset base subject to depletion at December 31, 2005.

Harvest performs an impairment test at the end of each calendar year. The petroleum and natural gas future prices used in the impairment test were obtained from third party engineers and were adjusted for contractual arrangements relating to pricing and quality differentials specific to Harvest. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying value of its petroleum and natural gas assets as at December 31, 2005 and 2004, and therefore no impairment was recorded in either of the periods ended on these dates.

Commodity price and US$/C$ exchange rate assumptions reflected in the impairment test as at December 31, 2005 were as follows:

Year	WTI Oil (US$/barrel)	Foreign Exchange Rate	Edmonton Light Crude Oil (C$/barrel)	AECO (C$/Gigajoule)
2006	57.50	0.85	66.60	10.05
2007	55.40	0.85	64.20	9.05
2008	52.50	0.85	60.70	8.05
2009	49.50	0.85	57.20	7.00
2010	46.90	0.85	54.10	6.85
Thereafter (escalation)	2.5%	0%	2.5%	2.5%

6. DEFERRED CHARGES

	December 31, 2005	December 31, 2004
Deferred losses on risk management contracts	**$ –**	$ 10,759
Financing costs	**11,064**	12,781
Discount on senior notes	**1,704**	2,000
	$ 12,768	$ 25,540

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2005	December 31, 2004
Trade accounts payable	**$ 22,484**	$ 13,697
Accrued interest	**4,959**	5,993
Trust Unit Incentive Plan and Unit Award Incentive Plan [Note 13]	**17,828**	9,774
Premium on price risk management contracts	**462**	4,500
Accrued closing adjustments on asset acquisition	**–**	13,546
Other accrued liabilities	**53,223**	27,139
Large corporation taxes payable	**620**	1,602
	$ 99,576	$ 76,251

8. 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 $373 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 10% and inflation rate of approximately 1% were used to calculate the fair value of the asset retirement obligation as at December 31, 2004. Upward revisions totaling approximately $8.7 million were made to the asset retirement obligation at December 31, 2005. The upward revisions were discounted using a revised credit adjusted risk-free discount rate of 8%.

A reconciliation of the asset retirement obligation is provided below:

Year ended December 31	2005	2004
Balance, beginning of year	**$ 90,085**	$ 42,009
Liabilities incurred	**7,328**	53,488
Revision of estimates	**8,656**	(8,704)
Liabilities settled	**(4,146)**	(929)
Accretion expense	**8,770**	4,221
Balance, end of year	**$ 110,693**	$ 90,085

9. BANK LOAN

At December 31, 2005, Harvest had $13.9 million drawn under a $400 million credit facility. The $400 million credit facility was secured by a $750 million charge over all of the assets of the operating subsidiaries and a guarantee from the Trust and consisted of a $375 million production facility plus a $25 million operating facility. This credit facility enabled funds to be borrowed, repaid and re-borrowed within the term in either Canadian or U.S. dollars and it may have been extended for an additional 364 day period on an annual basis with the agreement of the lenders. If the term was not extended, the credit facilities would have converted to a 366 non-revolving term loan with no payment due until August 2, 2007.

Amounts borrowed under the Production Facility and Operating Facility bear interest at a floating rate based on the applicable Canadian or U.S. prime rate plus 0 basis points to 225 basis points depending on the type of borrowing and Harvest's debt to annualized cash flow ratio, as defined in the Credit Agreement. For the year ended December 31, 2005 we paid interest at an average rate of 4.75% (2004 – 4.65%) and 6.39% (2004 – 5.14%) for the Canadian and U.S. amounts drawn, respectively. Availability under this facility was subject to a reserve based borrowing calculation performed by the lender at least on a semi-annual basis.

This facility was fully repaid on February 2, 2006. See Note 21 for a description of Harvest's new bank facility.

10. CONVERTIBLE DEBENTURES

The Trust has issued three series of unsecured subordinated debentures. Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series. The debentures are convertible into fully paid and non-assessable Trust Units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by the Trust for redemption. The conversion price per Trust Unit is specified for each series and may be supplemented with a cash payment for accrued interest and in lieu of any fractional Trust Units resulting from the conversion.

The debentures may be redeemed by the Trust at its option in whole or in part prior to their respective maturity dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time. The Trust may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The following is a summary of the three 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[(a)]	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May 30/09
Aug 10, 2004	8%	$ 100	$ 16.07[(a)]	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

(a) The conversion price for the 9% convertible debentures and the 8% convertible debentures changed from $14.00 and $16.25 per unit respectively, as a result of the special distribution described in Note 12.

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

	9% Series		8% Series		6.5% Series		Total
	Number	Amount	Number	Amount	Number	Amount	Amount
January 29, 2004 issuance	60,000	$ 60,000	–	$ –	–	$ –	$ 60,000
August 10, 2004 issuance	–	–	100,000	100,000	–	–	100,000
Portion allocated to equity	–	(17)	–	(745)	–	–	(762)
Accretion of non-cash interest expense	–	2	–	23	–	–	25
Converted into Trust Units	(49,300)	(49,287)	(84,841)	(84,226)	–	–	(133,513)
As at December 31, 2004	10,700	$ 10,698	15,159	$ 15,052	–	$ –	$ 25,750
August 2, 2005 issuance					75,000	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	(8,923)	(8,921)	(11,373)	(11,299)	(33,527)	(31,382)	(51,602)
As at December 31, 2005	1,777	$ 1,777	3,786	$ 3,764	41,473	$ 38,914	$ 44,455
Fair value of convertible debentures at December 31, 2005		**$ 4,700**		**$ 8,670**		**$ 49,768**	**$ 63,138**
Face value of convertible debentures at December 31, 2005		**$ 1,777**		**$ 3,786**		**$ 41,473**	**$ 47,036**

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	Total
January 29, 2004 issuance, net	$ 17	$ –	$ –	$ 17
August 10, 2004 issuance, net	–	745	–	745
Converted into Trust Units, net	(14)	(632)	–	(646)
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

See Note 21 regarding subsequent assumption of additional convertible debentures associated with the Viking Arrangement.

11. 7 7/8% SENIOR NOTES

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of the Trust, issued US$250 million of 7 7/8% Senior Notes for cash proceeds of $311,951,000. The balance is reflected using the current Canadian/U.S. dollar exchange rate on each successive balance sheet. The balance as at December 31, 2005 is $290,750,000 reflecting exchange gains of $21,201,000 since its inception. The 7 7/8% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year and mature on October 15, 2011. Prior to maturity, redemptions are permitted as follows:

- Before October 15, 2007 at 107.875% of the principal amount*
- Beginning on October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

** Limited to 35% of the notes issued and limited to repayment with proceeds from an equity offering.*

The 7 7/8% Senior Notes contain certain covenants restricting, amounts other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1. In addition, the 7 7/8% Senior Notes restrict the Trust's ability to pay distributions to Unitholders. Distributions are limited to 80% of cumulative cash flows from operations, before settlement of asset retirement obligations and changes in non-cash working capital, from the date of issuance of the 7 7/8% Senior Notes. An excess carry forward balance of approximately C$300 million exists as at December 31, 2005.

The 7 7/8% Senior Notes are unconditionally guaranteed by the Trust and all of its wholly-owned subsidiaries. The fair value of the 7 7/8% Senior Notes at December 31, 2005 approximated book value.

12. UNITHOLDERS' CAPITAL

(a) Authorized

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

(b) Issued

	Number of Units	(restated, Note 3) Amount
As at January 1, 2004	**17,109,006**	$ 117,407
Plan of Arrangement [Note 4]	2,720,837	40,183
Conversion of subscription receipts	12,166,666	175,200
Convertible debenture conversions – 9% series [Note 10]	3,521,404	49,301
Convertible debenture conversions – 8% series [Note 10]	5,220,995	84,858
Exchangeable share retraction [Note 14]	152,396	2,200
Distribution reinvestment plan issuance	751,727	12,553
Unit appreciation rights exercise	145,469	721
Issue costs	–	(16,899)
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 14]	299,123	3,865
Distribution reinvestment plan issuance (including premium distribution reinvestment plan)	1,167,109	36,217
Special distribution	465,285	10,678
Unit appreciation rights exercise and other	328,344	12,084
Issue costs	–	(9,949)
As at December 31, 2005	**52,982,567**	$ 747,312

On February 28, 2005, the Trust declared a special distribution of 2004 income to Unitholders effective as at December 31, 2004. The special distribution was paid in units, with each Unitholder of record on March 31, 2005 receiving 0.01098 of a Trust Unit per Trust Unit held on that date.

On August 17, 2005, the Trust implemented a premium distribution reinvestment plan. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to the Trust is the same as the regular distribution reinvestment plan whereby it settles distributions with units rather than cash, at a discount to the current market price of the Units.

(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	2005	2004
Net income, basic	$ 104,946	$ 11,241
Non-controlling interest	149	–
Interest on convertible debentures	1,128	–
Net income, diluted[1]	$ 106,223	$ 11,241

Weighted average Trust Units adjustments	2005	2004
Number of Units		
Weighted average Trust Units outstanding, basic	46,557,151	25,033,567
Effect of convertible debentures	880,208	–
Effect of exchangeable shares	274,768	–
Effect of Employee Unit Incentive Plans	795,754	1,140,738
Weighted average Trust Units outstanding, diluted[2]	48,507,881	26,174,305

(1) Net income, diluted excludes the impact of the conversions of the 6.5% convertible debentures of $1,736,000 for the year ended December 31, 2005. The impact of the non-controlling interest of $225,000 and the impact of the conversion of the 9% and 8% debentures of $5,223,000 for the year ended December 31, 2004 was also excluded, as the impact was anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the year ended December 31, 2005 does not include the unit impact of 749,000 for the 6.5% convertible debentures. For the year ended December 31, 2004 it does not include the impact of the conversion of the debentures as the impact would be anti-dilutive. Total Units excluded were 6,004,145. The impact of the exchangeable shares has also been excluded as the impact would be anti-dilutive. Total Units excluded were 290,090, which reflects the weighted average exchangeable shares outstanding based on the conversion ratio at December 31, 2004.

13. EMPLOYEE UNIT INCENTIVE PLANS

Trust Unit Rights Incentive Plan

The Trust Unit Incentive Plan was established in 2002. In December 2004, the plan was modified such that the ability to settle a Unit appreciation right with cash is now solely at the option of the holder and not subject to the discretion of the Board of Directors of Harvest Operations. The Trust is authorized to grant non-transferable Unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding Trust Units and the number of Trust Units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the Trust Units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the Trust Units subsequent to the date of grant of the respective right, provided that the Trust's net operating cash flow (on an annualized basis) exceeds 10% of the Trust's recorded cost of capital assets less all debt, working capital deficiency (surplus) or debt equivalent instruments, accumulated depletion, depreciation and amortization charges, asset retirement obligations, and any future income tax liability associated with such capital assets. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in cash on a semi-annual basis.

As a result of the modification of the Trust Unit incentive plan in 2004, the Trust is required to recognize a liability on its consolidated balance sheet associated with the Units reserved under the plan. This obligation represents the difference between the market value of the Trust Units and the exercise price of the vested Unit rights outstanding under the plan. As such, an obligation of $17.8 million (2004 – $9.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 1,305,143 (2004 – 1,117,725) Trust Units outstanding under the plan at December 31, 2005. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

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

	2005		2004	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of year	**1,117,725**	**$ 11.92**	1,065,150	$ 9.04
Granted	**793,325**	**26.69**	445,600	16.47
Exercised	**(420,157)**	**9.49**	(253,750)	8.30
Cancelled	**(185,750)**	**25.70**	(139,275)	10.91
Outstanding before exercise price reductions	**1,305,143**	**19.72**	1,117,725	11.92
Exercise price reductions	**–**	**(2.99)**	–	(1.83)
Outstanding, end of year	**1,305,143**	**$ 16.73**	1,117,725	$ 10.09
Exercisable before exercise price reductions	**109,068**	**$ 13.56**	206,688	$ 8.89
Exercise price reductions	**–**	**(4.04)**	–	(2.64)
Exercisable, end of year	**109,068**	**$ 9.52**	206,688	$ 6.25

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2005.

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	Outstanding At December 31, 2005	Outstanding Exercise Price Net of Price Reductions(a)	Remaining Contractual Life(a)	Exercisable At December 31, 2005	Exercisable Exercise Price Net of Price Reductions (a)
$ 8.00 – $10.21	$ 2.75 – $ 4.96	**183,125**	$ 2.98	1.9	**8,750**	$ 4.98
$10.30 – $13.15	$ 5.55 – $ 9.15	**162,575**	7.78	2.7	**64,525**	7.38
$13.35 – $17.95	$ 9.54 – $15.04	**212,875**	11.98	3.5	**19,300**	11.48
$18.55 – $25.68	$15.72 – $23.45	**607,968**	21.61	4.2	**16,493**	17.98
$27.49 – $37.56	$25.93 – $36.00	**138,600**	31.36	4.6	**–**	N/A
$ 8.00 – $37.56	$ 2.75 – $36.00	**1,305,143**	$ 16.73	3.6	**109,068**	$ 9.52

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

Unit Award Incentive Plan

In the year ended December 31, 2004, the Trust implemented a Unit award incentive plan ("Unit award plan"). The Unit award plan authorizes the Trust to grant awards of Trust Units to directors, officers, employees and consultants of the Trust and its affiliates. Subject to the Board of Directors' discretion, awards vest annually over a four year period and, upon vesting, entitle the holder to receive the number of Trust Units subject to the award or the equivalent cash amount. The number of Units to be issued is adjusted at each distribution date for an amount approximately equal to the foregone distributions. The fair value associated with the Trust Units granted under the Unit award plan is expensed in the statement of income over the vesting period.

Upon completion of the Plan of Arrangement with Viking [see Note 21], Unitholders approved the issuance of up to 0.5% of outstanding Trust Units under the Unit award plan.

Number	December 31, 2005	December 31, 2004
Outstanding, beginning of year	**10,662**	–
Granted	**23,466**	15,000
Adjusted for distributions	**1,237**	662
Cancelled	**–**	(5,000)
Outstanding, end of year	**35,365**	10,662

Upon closing of the Viking Plan of Arrangement all awards and rights issued under the Trusts' employee unit incentive plans vested and additional rights and awards were issued under both plans.

The Trust has recognized compensation expense of $17.3 million (2004 – $11.4 million), including non cash compensation expense of $16.3 million (2004 – $9.5 million), for the year ended December 31, 2005, related to the Trust Unit Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

14. EXCHANGEABLE SHARES

(a) Authorized

Harvest Operations is authorized to issue an unlimited number of exchangeable shares without nominal or par value.

(b) Issued

Exchangeable shares, series 1	December 31, 2005	December 31, 2004
Outstanding, beginning of year	**455,547**	–
Issued pursuant to corporate acquisition	–	600,587
Shareholder retractions	**(272,578)**	(145,040)
Outstanding, end of year	**182,969**	455,547
Exchange ratio	**1.17475**	1.06466

On June 30, 2004, 600,587 exchangeable shares, series 1 were issued at $14.77 each as partial consideration under a Plan of Arrangement [Note 4(a)]. The exchangeable shares, series 1 can be converted at the option of the holder at any time into Trust Units. The number of Trust Units issued to the holder upon conversion is based upon the applicable exchange ratio at that time. The exchange ratio is calculated monthly and adjusts to account for distributions paid to Unitholders during the period that the exchangeable shares are outstanding. The exchangeable shares are not eligible to receive distributions. The exchangeable shares that have not been converted by the holder may be redeemed in part or in their entirety by Harvest Operations at any date until June 30, 2009, at which time all remaining exchangeable shares in this series will be redeemed for Trust Units at the then current exchange ratio [see Note 21].

(c) Non-Controlling Interest

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

	December 31, 2005	(restated, Note 3) December 31, 2004
Non-controlling interest, beginning of year	**$ 6,895**	$ –
Issue of exchangeable shares	–	8,870
Exchanged for Trust Units	**(3,865)**	(2,200)
Current period income attributable to non-controlling interest	**149**	225
Non-controlling interest, end of year	**$ 3,179**	$ 6,895
Accumulated income attributed to non-controlling interest	**$ 374**	$ 225

15. INCOME TAXES

The future income tax asset and liability on the consolidated balance sheet reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of Harvest Operations and the Trust's other corporate subsidiaries and their corresponding income tax bases as at that date. Changes in the balance between periods is reflected as future income tax expense or recovery in the consolidated statements of income. The legislated reductions in the Federal and Provincial income tax rates were implemented as expected in 2004. Federal rates are expected to decline further until 2007, resulting in an effective tax rate of approximately 34% for the Trust, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

The provision for future income taxes varies from the amount that would be computed by applying the combined Canadian Federal and Provincial income tax rates to the reported income before taxes as follows:

	2005	2004
Income before taxes	$ 72,709	$ 2,609
Combined Canadian Federal and Provincial statutory income tax rate	37.6%	38.9%
Computed income tax expense at statutory rates	27,339	1,015
Income earned by flow through entities	(64,763)	(14,802)
	(37,424)	(13,787)
Increased expense (recovery) resulting from the following:		
Non-deductible crown charges	4,242	1,278
Resource allowance	(3,499)	(1,731)
Non-deductible portion of capital loss (gain)	(1,834)	2,633
Unit appreciation rights expense	4,455	560
Income tax rate change	2,300	549
Other	(611)	136
Future income tax recovery	$ (32,371)	$ (10,362)

The components of the future income tax liability (asset) are as follows:

	2005	2004
Net book value of petroleum and natural gas assets in excess of tax pools	$ 41,270	$ 46,333
Asset retirement obligation	(12,826)	(9,691)
Net unrealized losses related to risk management contracts and foreign exchange positions – current	(17,483)	2,293
Net unrealized losses related to risk management contracts and foreign exchange positions – long-term	(1,532)	–
Non-capital loss carry forwards for tax purposes	(4,701)	(1,172)
Deferral of taxable income in Partnership	1,425	2,339
Working capital and other items	(6,917)	(5,431)
Future income tax liability (asset), net	$ 2,300	$ 34,671

The non-capital losses described above expire between the years 2010 and 2015.

The amount of tax pools available to the Trust, in all of its subsidiaries, are approximately $476 million. These tax pools are primarily made up of resource tax pools, undepreciated capital cost tax pools, and unit issue cost tax pools. These tax pools are available for deduction in future years to enable the Trust to manage its exposure to income taxes. The temporary differences for the non-taxable entities are approximately $500 million.

16. 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.

(a) Fair Values

Financial instruments of the Trust consist mainly of accounts receivable, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and senior notes. Other than as disclosed in Note 10 for the convertible debentures, there were no significant differences between the carrying values of these financial instruments reported on the balance sheet and their estimated fair values due to their short-term to maturity and the fact that the risk management contracts are presented at fair value on the balance sheet.

(b) Interest Rate Risk

The Trust is exposed to interest rate risk on its bank loan as interest rates are determined in relation to floating market rates; Harvest's convertible debentures and 7⅞% Senior Notes have fixed interest rates.

(c) Credit Risk

Substantially all accounts receivable are due from customers in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with the Trust. The Trust periodically assesses the financial strength of its partners and customers, including parties involved in marketing or other commodity arrangements. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

(d) Foreign Exchange Rate Risk

The Trust is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices. In addition, the Trust's 7⅞% Senior Notes are denominated in U.S. dollars (US$250 million). These notes act as an economic hedge to help offset the impact of exchange rate movements on commodity sales during the year. As at December 31, 2005 the full balance of the notes is still outstanding and is not repayable until October 15, 2011. Interest is payable semi-annually on the notes in U.S. dollars.

(e) Risk Management Contracts

The Trust uses fixed price petroleum sales contracts and financial instruments to manage its commodity price exposure. Under the terms of some of these instruments, Harvest Operations is required to provide security to its counterparties from time to time based on the underlying market value of those contracts. As at December 31, 2005, no security was provided. The Trust is also exposed to counterparty risk for these risk management contracts. This risk is managed by diversifying the Trust's risk management portfolio among a number of counterparties and by dealing with large investment grade institutions.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2005.

Quantity	Type of Contract	Term	Reference	Fair Value
8,750 bbl/d	Participation swap	January – December 2006	US$38.16 [a]	$ (44,903)
5,000 bbl/d	Participation swap	July – December 2006	US$45.17 [a]	(9,057)
7,500 bbl/d	Indexed put contract – bought put	January – June 2006	US$34.00 [c]	(779)
3,750 bbl/d	Indexed put contract – sold call	January – June 2006	US$34.00 [c]	(22,194)
3,750 bbl/d	Indexed put contract – bought call	January – June 2006	US$44.00 [c]	14,515
5,000 bbl/d	Indexed put contract – bought put	January – December 2006	US$55.00 [c]	4,645
2,500 bbl/d	Indexed put contract – sold call	January – December 2006	US$55.00 [c]	(10,773)
2,500 bbl/d	Indexed put contract – bought call	January – December 2006	US$65.00 [c]	4,706
2,500 bbl/d	Indexed put contract – sold call	January – December 2006	US$70.00 [c]	(3,022)
2,500 bbl/d	Indexed put contract – bought call	January – December 2006	US$83.00 [c]	1,002
U.S.12.9 M	Foreign currency call contract	Dec. 2005 – Jan. 2006	1.163 Cdn./U.S.	(108)
Total current portion of fair value deficiency				**$ (65,968)**
5,000 bbl/d	Participating swap	January 2006 – June 2007	US$49.03 [b]	(7,105)
5,000 bbl/d	Indexed put contract – bought put	January – December 2007	US$50.00 [c]	7,559
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	US$50.00 [c]	(17,563)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	US$60.00 [c]	11,274
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	US$70.00 [c]	(6,828)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	US$83.00 [c]	3,353
200 Mcf/d	Fixed price contract	Jan. 2006 – Dec. 2008	C$4.29 [d]	(1,139)
Total long-term portion of fair value deficiency				**$ (10,449)**

(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 calls reflect an "indexed put option". These series of puts and calls serve to fix a floor price while retaining upward price exposure on a portion of price movements above the floor price.

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

Quantity	Type of Contract	Term	Reference	Fair Value
4,000 bbl/d	Differential swap – Bow River	January 2006 – June 2006	29.90%	$ 3,424
5,000 bbl/d	Differential swap – Bow River	January 2006 – June 2006	27.50%	4,664
4,000 bbl/d	Differential swap – Bow River	July 2006 – December 2006	29.58%	1,550
5,000 bbl/d	Differential swap – Bow River	July 2006 – December 2006	27.50%	2,409
1,000 bbl/d	Differential swap – Wainwright	January – June 2006	29.90%	1,171
1,000 bbl/d	Differential swap – Wainwright	July – December 2006	29.58%	877
5,000 GJ/d	Natural gas price collar contract	April – October 2006	C$9.00-$13.06	378
25 MWH	Electricity price swap contracts	January – March 2006	C$48.00	929
35 MWH	Electricity price swap contracts	January – December 2006	C$48.58	5,829
Total current portion of fair value				**$ 21,231**
25 MWH	Electricity price swap contracts	January – December 2007	C$55.00	2,190
25 MWH	Electricity price swap contracts	January – December 2008	C$55.00	438
Total long-term portion of fair value				**$ 2,628**

At December 31, 2005, the net unrealized loss position reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $52.6 million (2004 – $15.4 million).

For the year ended December 31, 2005, the total unrealized loss recognized in the consolidated statement of income, including amortization of deferred charges and gains, was $45.1 million (2004 – $11.3 million). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

At October 1, 2004, the Trust discontinued hedge accounting for all of its risk management contracts. For those contracts where hedge accounting had previously been applied, a deferred charge or credit was recorded equal to the fair value of the contracts at the time hedge accounting was discontinued with a corresponding amount recorded as a deferred loss or credit on risk management contracts, respectively on the consolidated balance sheet. The deferred charge or credit is recognized in income in the period in which the underlying hedged transaction is recognized.

For the year ended December 31, 2005, $10.8 million (2004 – $14.9 million) of the deferred charge and $1.8 million (2004 – $350,000) of the deferred credit has been amortized and recorded in unrealized net losses on risk management contracts in the consolidated statements of income. At December 31, 2005, nil (2004 – $10.8 million) and $398,000 (2004 – $2.2 million) remain in deferred charges and deferred credits, respectively on the balance sheet, related to the impact of discontinuing hedge accounting.

17. RELATED PARTY TRANSACTIONS

A director of Harvest Operations and a corporation controlled by that director had advanced $25 million pursuant to the equity bridge notes as at January 1, 2004. On January 2, 2004 Harvest Operations paid $665,068 in accrued interest on these notes. On January 26 and 29, 2004, Harvest Operations repaid the outstanding principal amount and paid $185,232 of interest accrued. The notes were amended on June 29, July 7 and July 9, 2004. These notes were drawn by $30 million ($25 million on June 29, 2004 and $5 million on July 9, 2004) and repaid as to $20 million on August 11, 2004 and $10 million on December 30, 2004. The notes accrued interest at 10% per annum, were secured by a fixed and floating charge on the assets of the Trust and were subordinate to the interests of the senior secured lenders pursuant to Harvest Operations' credit facility.

18. CHANGE IN NON-CASH WORKING CAPITAL

	Year Ended December 31, 2005	Year Ended December 31, 2004
Changes in non-cash working capital items:		
Accounts receivable	**$ (29,738)**	$ (24,860)
Prepaid expenses and deposits	**1,888**	9,117
Current portion of risk management contracts assets	**(12,370)**	(8,861)
Accounts payable and accrued liabilities	**23,325**	58,168
Cash distribution payable	**10,186**	4,936
Current portion of risk management contracts liability	**38,041**	–
Current portion of future income tax asset	**(19,874)**	27,927
	$ 11,458	$ 66,427
Changes relating to operating activities	**$ (22,519)**	$ (11,103)
Changes relating to financing activities	**(1,035)**	5,097
Changes relating to investing activities	**9,927**	16,547
Add: Non cash changes	**25,085**	55,886
	$ 11,458	$ 66,427

19. COMMITMENTS, CONTINGENCIES AND GUARANTEES

From time to time, the Trust is involved in litigation or has claims brought against it in the normal course of business operations. Management of Harvest Operations is not currently aware of any claims or actions that would materially affect the Trust's reported financial position or results from operations.

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

The Trust has letters of credit outstanding in the amount of approximately $7.7 million primarily provided to electricity infrastructure providers. These letters are provided by Harvest Operations' lenders pursuant to the credit agreement [Note 9]. 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 December 31, 2005:

	Payments Due by Period						
	2006	2007	2008	2009	2010	Thereafter	Total
Debt repayments (1)	–	13,869	–	–	–	290,750	304,619
Capital commitments	4,936	–	–	–	–	–	4,936
Operating leases (2)	2,238	2,063	1,993	1,993	1,234	–	9,521
Total contractual obligations	7,174	15,932	1,993	1,993	1,234	290,750	319,076

(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.

20. RECONCILIATION OF THE CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP which, in most respects, conforms to U.S. GAAP. Any differences in accounting principles as they have been applied to the accompanying consolidated financial statements are not material except as described on page 88. Items required for financial disclosure under U.S. GAAP may be different from disclosure standards under Canadian GAAP; any such differences are not reflected here.

The application of U.S. GAAP would have the following effects on net income as reported:

	Year Ended December 31, 2005	Year Ended December 31, 2004
Net income under Canadian GAAP	**$ 104,946**	$ 11,241
Adjustments		
Unrealized loss on derivative financial instruments (f)	**8,980**	3,886
Future tax impact of deferred charges relating to derivative financial instruments (f) (g)	**(3,019)**	2,885
Depletion, depreciation and accretion (b)	**1,592**	–
Future tax impact on capital assets (b) (g)	**(535)**	–
Future income tax effect on unrealized loss on derivative financial instruments (f) (g)	**–**	(5,251)
Non-cash interest expense on debentures (d)	**239**	25
Amortization of deferred financing charges (d)	**(38)**	(99)
Non-controlling interest (e)	**149**	225
Non-cash general and administrative expenses (c)	**–**	1,455
Net income under U.S. GAAP	**112,314**	14,367
Increase in redemption value of Trust Units under U.S. GAAP (e)	**(638,044)**	(298,893)
Net loss available to Unitholders under U.S. GAAP (e)	**$ (525,730)**	$ (284,526)
Basic		
Net income per Trust Unit under U.S. GAAP (before changes in redemption value of Trust Units)	**$ 2.41**	$ 0.57
Net loss available to Unitholders per Trust Unit under U.S. GAAP	**$ (11.29)**	$ (11.24)
Diluted		
Net income per Trust Unit under U.S. GAAP (before changes in redemption value of Trust Units)	$ 2.33	$ 0.54
Net loss available to Unitholders per trust unit under U.S. GAAP	**$ (11.29)**	$ (11.24)
Net loss – U.S. GAAP	**$ (525,730)**	$ (284,526)
Future income tax recovery – U.S. GAAP	**(28,817)**	(7,996)
Net loss before taxes – U.S. GAAP	**$ (554,547)**	$ (292,522)

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported:

	December 31, 2005		December 31, 2004	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Capital assets (a) (b)	$ 1,130,155	$ 1,131,747	$ 918,397	$ 918,397
Deferred charges (d) (f) (h)	$ 12,768	$ 10,951	$ 25,540	$ 12,768
Future income tax (g)	$ 22,975	$ 22,975	$ 3,101	$ –
Liabilities				
Deferred gains (f)	$ 1,389	$ 991	$ 2,177	$ –
Senior notes (h)	$ 290,750	$ 289,045	$ 300,500	$ 298,488
Convertible debentures – liability (d)	$ 44,455	$ 47,036	$ 25,750	$ 25,859
Future income tax (f) (g)	$ 25,275	$ 25,944	$ 37,772	$ 31,786
Non-controlling interest (e)	$ 3,179	$ –	$ 6,895	$ –
Temporary equity (e)	$ –	$ 1,783,159	$ –	$ 867,452
Unitholders' Equity				
Unitholders' capital (e)	$ 747,312	$ –	$ 465,524	$ –
Equity component of convertible debentures (d)	$ 2,639	$ –	$ 116	$ –
Accumulated income	$ 135,665	$ (895,736)	$ 30,719	$ (370,005)

(a) Under Canadian GAAP, the Trust performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate. Under U.S. GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP impairment test are those in effect at year end. There was no impairment under U.S. GAAP at December 31, 2005 or 2004.

(b) Under Canadian GAAP, proved reserves are estimated using estimated future prices and costs. These proved reserves form the basis for the depletion calculation.

Under U.S. GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs. In the current year there is a significant difference in proved reserves under U.S. GAAP and Canadian GAAP and as a result a difference is realized in the depletion expense for 2005.

(c) Under Canadian GAAP, the Trust determines compensation expense related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2 (i).

Under U.S. GAAP, SFAS 123 "Accounting for Stock-Based Compensation" determines compensation expense using the same method as under Canadian GAAP for 2005 and 2004. The Trust Unit Incentive Plan and the Unit Award Incentive Plan both allow for the settlement of the award with cash at the holders option. In 2004, an adjustment is made to reflect compensation expense recorded under U.S. GAAP relating to rights issued in

2002 previously not expensed under Canadian GAAP. For the year ended December 31, 2005, no adjustment is required as the same accounting method has been applied under both Canadian and U.S. GAAP.

(d) Upon adoption of revised Canadian accounting standards for financial instruments (see Note 3), the Trust's convertible debentures were classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs for the debentures are allocated between the equity portion and deferred charges for the debt portion. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity.

Under U.S. GAAP, the convertible debentures in their entirety are classified as debt, and as a result all of the issue costs would be recorded as deferred charges. To the extent a portion of the issue costs were allocated to equity under Canadian GAAP there is a difference in amortization for the related deferred charges. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP.

(e) Under the Trust's Indenture, Trust Units are redeemable at any time on demand by the Unitholder for cash. Under U.S. GAAP, the amount included on the consolidated balance sheet for Unitholders' Equity would be reduced by an amount equal to the redemption value of the Trust Units as at the balance sheet date. The same accounting treatment would be applicable to the exchangeable shares. The redemption value of the Trust Units and the exchangeable shares is determined with respect to the trading value of the Trust Units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to permanent equity and is reflected as either an increase or decrease in earnings available to Unitholders for the year. Under Canadian GAAP the exchangeable shares are recorded as non-controlling interest.

(f) Under U.S. GAAP, SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" requires that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. U.S. GAAP requires that a company formally document, designate, and assess the effectiveness of derivative instruments before hedge accounting may be applied. The Trust had not formally documented and designated any hedging relationships as at December 31, 2005 or December 31, 2004 and as such, the risk management contracts were not eligible for hedge accounting treatment under U.S. GAAP.

The Trust implemented fair value accounting effective January 1, 2004 under Canadian GAAP and had designated a portion of its risk management contracts as hedges. During the year-ended December 31, 2004, the Trust discontinued hedge accounting for all risk management contracts under Canadian GAAP. Upon discontinuing hedge accounting, a deferred charge or gain is recorded representing the fair value of the contract at that time. This difference is amortized over the term of the contract. Under U.S. GAAP there were no contracts designated as hedges. To the extent deferred charges and credits were recorded and amortized when hedge accounting was discontinued, there is a difference between Canadian and U.S. GAAP. The deferred charges and gains continue to be amortized under Canadian GAAP for the year-ended December 31, 2005, and create a difference from U.S. GAAP.

(g) The Canadian GAAP liability method of accounting for income taxes is similar to the U.S. GAAP SFAS 109, "Accounting for Income Taxes", which requires the recognition of tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Trust's consolidated financial statements. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future income tax, whereas Canadian GAAP uses substantively enacted rates. There are no differences for the years ended December 31, 2005 and December 31, 2004 relating to tax rate differences.

Upon adoption of fair value accounting for its risk management contracts under Canadian GAAP, deferred charges and credits were set up when hedge accounting was discontinued. As there is no tax base relating to these balances, a temporary difference was created. This difference does not exist under U.S. GAAP as there are no deferred charges or credits under U.S. GAAP. In addition, to the extent differences exist between depletion, depreciation and amortization and consequently the capital assets balance, there is a difference in future income tax. For the year ended December 31, 2004, to the extent there were historical differences with respect to Canadian and U.S. GAAP due to risk management assets and liabilities, these amounts are now required to be eliminated as the balances of those accounts under Canadian and U.S. GAAP are now the same.

(h) Under Canadian GAAP, the discount on the senior notes has been recorded in deferred charges. Under U.S. GAAP, this amount is required to be applied against the senior notes balance.

The following are standards and interpretations that have been issued by the Financial Accounting Standards Board ("FASB") which are not yet in effect for the periods presented but would comprise U.S. GAAP when implemented:

In December 2004, FASB issued statement 123R *"Share Based Payments"* that addresses the accounting for share-based payment transactions in which an enterprise receives employee services in exchange for (a) equity instruments of the enterprise or (b) liabilities that are based on the fair value of the enterprise's equity instruments or that may be settled by the issuance of such equity instruments. The proposal eliminates the ability to account for share-based compensation transactions using APB 25, "Accounting for Stock Issued to Employees", and generally requires instead, that such transactions be accounted for using a fair-value-based method. The effective date would be for the first annual period beginning on or after June 15, 2005. Management has not yet assessed the impact of this standard on its consolidated financial statements.

In December 2004, FASB issued statement number 153 *"Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29"*. This Statement amends Opinion 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The effective date of this statement is for fiscal periods beginning after June 15, 2005. Management does not expect this statement to have a material impact on its consolidated financial statements.

In May 2005, FASB issued Statement No. 154 *"Accounting Changes and Error Corrections – a replacement of APB No. 20 and FASB Statement No. 3"*. This statement replaces APB Opinion No. 20 "Accounting Changes", and FASB Statement No. 3 "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. Opinion 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. This Statement is effective for accounting changes made in fiscal years beginning after December 15, 2005 and will be applied prospectively.

In February 2006, FASB issued Statement No. 155 *"Accounting for Certain Hybrid Financial Instruments – an amendment of FASB Statements no. 133 and 140"* This statement amends FASB Statements No. 133 *"Accounting for Derivative Instruments and Hedging Activities"*, and No. 140 *"Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities"*. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1 *"Application of Statement 133 to Beneficial Interests in Securitized Financial Assets"*. The statement a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of Statement 133, c)establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives, and e) amends statement 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006 with early adoption permitted.

Additional disclosures required under U.S. GAAP:

(thousands of Canadian dollars)	**December 31, 2005**	December 31, 2004
Components of accounts receivable		
Trade	**$ 16,555**	$ 14,743
Accruals	**57,211**	29,285
	$ 73,766	$ 44,028
Components of prepaid expenses and deposits		
Prepaid expenses	**$ 1,104**	$ 1,730
Funds on deposit	**22**	1,284
	$ 1,126	$ 3,014

21. SUBSEQUENT EVENTS

(a) On February 3, 2006 the Unitholders of Harvest Energy Trust and Viking Energy Royalty Trust ("Viking") voted to approve a resolution to effect a plan of arrangement (the "Arrangement") by which Unitholders of Viking received 0.25 Harvest Trust Units for every Viking Unit held, which represents approximately 45.8 million Harvest Trust Units and the Trust acquired all of the assets and assumed all of the liabilities of Viking. The total purchase price is estimated to be $1.6 billion (including estimated transaction costs of approximately $10 million) based on currently available information. Amendments to the purchase price estimate may be made as final information becomes available. The Arrangement resulted in Harvest assuming Viking's 10.5% and 6.4% unsecured subordinated convertible debentures. The conversion price of the debentures into Harvest Units was adjusted to $29.00 for the 10.5% series and $46.00 for the 6.4% series to reflect the Trust Unit exchange ratio.

The Arrangement provided for the vesting of all of the rights issued under the Trust Unit Incentive Plan and the awards issued under the Unit Award Plan. Exchangeable shareholders were also able to convert their exchangeable shares to Units as a result of the Arrangement. After the Arrangement approximately 26,902 exchangeable shares are remaining and Harvest will issue a redemption notice for cash to the remaining exchangeable shareholders.

(b) On February 3, 2006 and concurrent with the Trust's acquisition of the assets of the Viking Energy Royalty Trust, the Trust entered into a new $750 million three year extendible revolving Credit Facility. With the consent of the lenders, this facility may be extended on an annual basis for an additional 364 days and may also be increased to $900 million during secondary syndication which is expected to close by March 31, 2006. 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 Cash Flow Ratio as defined in the Credit Agreement. Availability under this facility is subject to quarterly financial covenants requiring that the Senior Debt to Cash Flow Ratio is less than 3 to 1, the Total Debt to Cash Flow Ratio is less than 3.5 to 1, Senior Debt to Capitalization is less than 50% and Total Debt to Capitalization is less than 55%, all as defined in the Credit Agreement.

(c) Subsequent to December 31, 2005, Harvest declared a distribution of $0.35 per unit for Unitholders of record on January 23, 2006 and declared a distribution of $0.38 for Unitholders of record on February 23, 2006 and March 22, 2006.

22. COMPARATIVES

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

CORPORATE INFORMATION

DIRECTORS

M. Bruce Chernoff,
Chairman(3)

Kevin Bennett(2)

Dale Blue(1)

David Boone(2)

John Brussa (3)

William Friley(3)

Verne Johnson(1)

Hector McFadyen(1)

Hank Swartout(2)

(1) Member of the Audit Committee.
(2) Member of the Reserves, Safety and Environment Committee.
(3) Member of the Corporate Governance/Compensation Committee.

OFFICERS

John Zahary, P.Eng.
President & Chief Executive Officer

James Campbell, P. Geol.
Vice President, Geosciences

Robert Fotheringham, C.A.
Vice President, Finance &
Chief Financial Officer

Rob Morgan, P.Eng.
Vice President, Engineering &
Chief Operating Officer

J.A. (Al) Ralston
Vice President, Operations

Jacob Roorda, P.Eng.
Vice President, Corporate

Steven Saunders, C.A.
Treasurer

David Rain, C.A.
Corporate Secretary

CORPORATE ADDRESS

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New York Stock Exchange: HTE

REGISTRAR AND TRANSFER AGENT

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310, 606 - 4th St. SW
Calgary, AB T2P 1T1
Telephone: (403) 233-2801

AUDITOR

KPMG LLP
Calgary, Alberta

LEGAL COUNSEL

CANADA
Burnet, Duckworth & Palmer

U.S.
Paul, Weiss, Rifkind, Wharton & Garrison

RESERVE EVALUATORS

McDaniel & Associates Ltd.
GLJ Petroleum Consultants Ltd.
Sproule & Associates Ltd.
Calgary, Alberta

INVESTOR RELATIONS

Cindy Gray,
Investor Relations Advisor

GENERAL INQUIRIES

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information@harvestenergy.ca

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1-866-666-1178

Please contact us if you would like to receive an investor package or be added to Harvest's mailing lists.

FORWARD-LOOKING STATEMENT DISCLAIMER

The disclosure in this report contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning Harvest's future outlook are based on information available at March 2006.

Harvest Energy Trust

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