Harvest Energy Trust

GOING AGAINST THE GRAIN

2004 ANNUAL REPORT

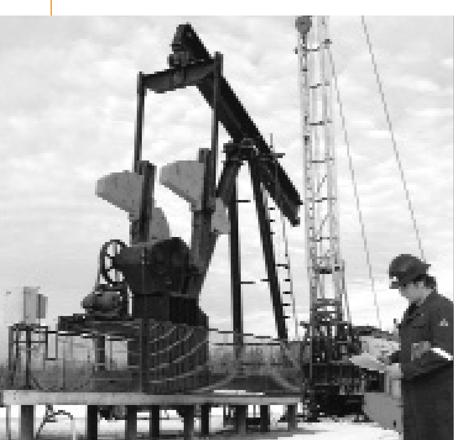
Corporate Profile

Harvest Energy Trust is a Calgary-based energy royalty trust that was formed in July of 2002, and trades on the Toronto Stock Exchange (TSX) under the symbol HTE.UN.

Harvest is focused on acquiring high-quality, mature properties where the production of crude oil, natural gas and natural gas liquids can be significantly increased and extended by Harvest's "hands-on" operating strategy. Harvest retains a significant portion of its cash flow to fund future growth in the form of both internal capital projects and accretive acquisitions. This strategy has allowed Harvest to grow to its present size in just over two years. Under this progressive approach, the technically focused team at Harvest seeks to maximize the value of every barrel by achieving higher ultimate production and resource recovery, to further the ultimate goal of stable distributions to Unitholders.

Notice of Meeting

The Annual Meeting of the Unitholders of Harvest Energy Trust will be held on May 4, 2005 at 3:00 pm in the Lecture Theatre Room at the Metropolitan Centre located at 333 – 4th Avenue SW in Calgary, Alberta. All Unitholders and interested parties are invited to attend.



Kirk Low, Operator
North Central Alberta

Left to Right: **Victor Gette,** Foreman
Larry Heck, Lead Operator
East Central Alberta

Chad Fonagy, Operator
Southeast Saskatchewan

Note: All figures in this annual report are in Canadian dollars, unless otherwise indicated.

Forward-Looking Statement Disclaimer

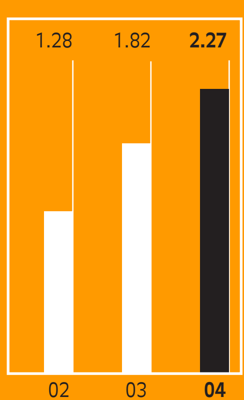
The following disclosure contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. 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 the Trust's future outlook are based on information available at March 2005.

Going Against the Grain

Our approach to value creation and our willingness to "go against the grain" makes Harvest a unique investment opportunity. We, at Harvest, make business decisions that are based on sound principles of creating the greatest long-term value for our Unitholders from our oil and natural gas operations, while always attempting to prudently remove uncertainty. We have the vision to see opportunities that others may not, and the courage to challenge conventional or traditional ways of doing things, which may destroy Unitholder value.

Our achievements in the past three years demonstrate the power of Harvest's strategy and the value of our focus, flexibility and commitment to creating sustainable value for our Unitholders.

Proved plus Probable Reserves Per Unit
(reserves per unit)



Proved plus Probable Reserve Life Index
(years)

2004 Performance

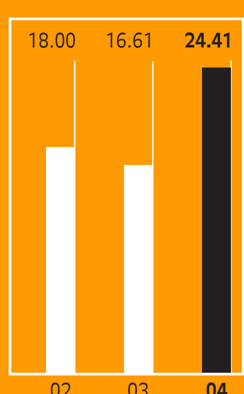
From left to right: **Scott Edwards,** Field Production Tech; **Steve Thorne,** Production Foreman; and **Robert Sayna,** District Superintendent – Southern Alberta

Average Daily Production
(BOE/d)

Proved plus Probable Reserves
(mmBOE)

Payout Ratio
(%)

Field Netback**
($/BOE)



Net Revenue
($/BOE)

* Reflects cash flow for period ended December 31, but distributions only for the month of December following the initial public offering.

** Before gains or losses on commodity derivatives.

HIGHLIGHTS

($000s, except where noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2004	2003	% Change	**2004**	2003	% Change
		(Restated) (6)			*(Restated)* (6)	
Financial						
Revenue, net of royalties	**107,446**	33,575	220%	**277,095**	102,939	169%
Cash flow from operations (5)	**53,545**	13,699	291%	**130,003**	46,492	180%
Per Trust Unit, basic (5)	**$ 1.31**	$ 0.85	54%	**$ 5.13**	$ 3.69	39%
Per Trust Unit, diluted (5)	**$ 1.27**	$ 0.82	55%	**$ 4.91**	$ 3.58	37%
Distributions per Trust Unit, declared (7)	**$ 0.60**	$ 0.60	0%	**$ 2.40**	$ 2.40	0%
Payout ratio (2) (5)	**46%**	75%	(39%)	**50%**	66%	(24%)
Capital asset additions (excluding acquisitions)	**8,873**	4,334	105%	**42,662**	27,209	57%
Acquisitions	**–**	80,271	(100%)	**706,000**	108,700	549%
Net debt (excluding derivative contracts) (3) (5)	**429,671**	78,555	447%	**429,671**	78,555	447%
Weighted average Trust Units outstanding, basic (4)	**40,937**	16,175	153%	**25,324**	12,591	101%
Trust Units outstanding, end of period	**41,788**	17,109	144%	**41,788**	17,109	144%
Trust Units, fully diluted (8), end of period	**45,088**	18,174	148%	**45,088**	18,174	148%
Operating						
Daily sales volumes (10)						
Light oil (bbl/d)	**12,228**	4,079	200%	**7,911**	1,028	670%
Medium oil (bbl/d)	**3,644**	4,662	(22%)	**4,324**	4,286	1%
Heavy oil (bbl/d)	**15,120**	5,756	163%	**8,495**	5,444	56%
Natural gas liquids (bbl/d)	**1,309**	70	1,770%	**471**	64	636%
Natural gas (mcf/d)	**28,338**	1,744	1,525%	**10,903**	1,311	732%
Total (BOE/d)(1)	**37,024**	14,858	149%	**23,019**	11,040	109%
Operating netback(5) ($/BOE)						
Revenues	**37.77**	29.13	30%	**39.33**	29.62	33%
Realized loss on derivative contracts	**(4.91)**	(2.18)	125%	**(6.47)**	(4.67)	39%
Royalties	**(6.23)**	(4.66)	34%	**(6.44)**	(4.07)	58%
As a percent of revenue (%)	**16.5%**	16.0%	3%	**16.4%**	13.8%	19%
Operating expense (9)	**(7.37)**	(9.50)	(22%)	**(8.48)**	(8.94)	(5%)
Operating netback (5)	**19.26**	12.79	51%	**17.94**	11.94	50%

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6 mcf of natural gas to 1 barrel of crude oil. BOEs may be misleading, particularly if used in isolation. The BOE 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.

(2) Ratio of distributions to cash flow from operations.

(3) Net debt is bank debt, senior notes, equity bridge notes, convertible debentures and any working capital deficit excluding the current portion of derivative contracts and the accounting liability related to our Trust Unit incentive plan. Equity bridge notes and convertible debentures are reflected as equity on our consolidated balance sheet in accordance with Canadian GAAP. In 2005, GAAP will require these amounts to be reflected as debt.

(4) Reflects both Trust Units and exchangeable shares.

(5) These are non-GAAP measures; please refer to "Certain Financial Reporting Measures" included in our MD&A.

(6) Restated to reflect the adoption of new CICA recommendations to account for asset retirement obligations. See Note 3 to the Consolidated Financial Statements.

(7) As if the Trust Unit was held throughout the period.

(8) Fully diluted units differ from diluted units for accounting purposes. Fully diluted includes Trust Units outstanding as at December 31 plus the impact of the conversion or exercise of exchangeable shares, Trust Unit rights and convertible debentures if completed at December 31.

(9) Includes realized gain on electricity derivative contracts of $0.18 and $0.24 for fourth quarter and full year 2004, respectively, and $0.26 and $0.39 for the same periods in 2003.

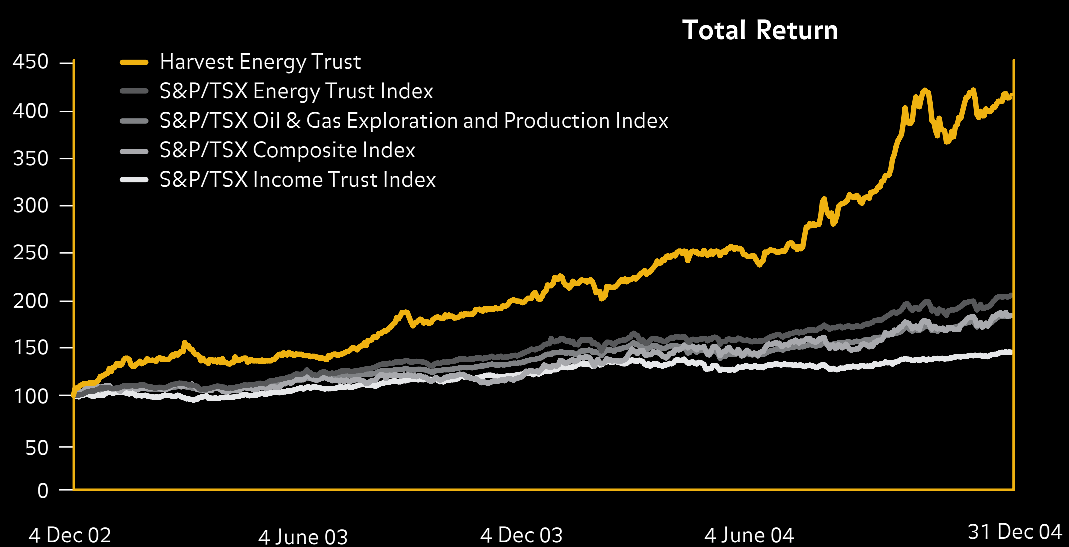
(10) Harvest classifies its oil production as light, medium and heavy according to NI 51-101 guidance.

Al Ralston
Vice President, Operations

David Rain
Vice President and Chief Financial Officer

Jacob Roorda
President

James Campbell
Vice President, Geosciences



From the IPO in December, 2002 to December 31, 2004, Harvest has delivered a total return to Unitholders of 317%. In 2004, Harvest's total return was 88%.

Letter to Unitholders

On behalf of the Harvest team, we are pleased to report on the Trust's activity during 2004 and discuss our strategy for 2005 and beyond.

From inception, Harvest has chosen a unique and sometimes challenging route to create maximum sustainable value for our Unitholders. This has included working with perceived shorter reserve life assets when long reserve life was viewed as more appropriate, having an oil focus when the apparent commodity of choice was natural gas, and maintaining a lower payout ratio when the norm was to distribute 100% or more of cash flow. Today, trusts are increasingly acquiring shorter life assets, crude oil has performed well as a commodity, and most trusts have lowered their payout ratio to 75% or less. We believe Harvest's results to date validate our strategy and demonstrate our willingness to “go against the grain” in pursuit of better returns for our Unitholders.

Focused Oil and Natural Gas Operations – Harvest's Business Model

Fundamentally, Harvest is an oil and natural gas production company with expertise in managing mature assets. Since inception, our underlying philosophy and business strategies have been focused on creating Unitholder value by undertaking quality property acquisitions, low-risk development and efficient operations. However, Harvest looks quite different today than when we went public in December 2002. In the span of just over 24 months, Harvest's reserves, reserves per unit, production and reserve life index have grown significantly. Our product mix is more diversified due to additional light crude oil and natural gas, and our netbacks have strengthened. The market capitalization of Harvest has risen 1,100% since our initial public offering, and in 2004 we further enhanced our capital structure by entering the U.S. debt market.

Left to Right:
Norman Wegerhoff, Sr. Geologist
Jessie Fletcher, Landman
Colin Page, Landman
Dave Cryer, Geophysical Interpreter

Left to Right:
Cory Thomas, Lead Operator
Victor Gette, Foreman
East Central Alberta

Future Sustainability

The foundation of Harvest's business model is a commitment to long-term sustainability. By targeting a low payout ratio, Harvest has access to undistributed cash flow to repay debt, fund our capital development program, or take advantage of acquisition opportunities.

Sustainability through Property Enhancement

Our business is based on the successful production and exploitation of mature oil and natural gas properties. Through activities such as low risk development drilling, ongoing optimization and property enhancement projects, we strive to maximize production and reserves. Harvest's skilled and innovative technical team seeks new ways to improve efficiency and reduce operating expenses. This contributes to increased cash flow, and can also extend the life of our reserves by making our wells economic for a longer period of time. Our sustainability is further supported by retaining a higher proportion of our cash flow, which enables us to fund these activities without necessarily issuing Trust Units and diluting existing Unitholders.

Sustainability through Accretive Acquisitions

When pursuing acquisitions, we focus on properties that can offer the greatest rate of return on our investment. This often includes producing properties with large accumulations of oil or natural gas in place, and high quality reservoirs. We do not turn away from assets that have a shorter reserve life or produce heavier gravity crude oil, because these assets can often be acquired at more favorable values, further contributing to higher returns. Given Harvest's ability to effectively manage mature assets, our focus is strictly on value potential and rate of return, rather than less relevant, specific asset characteristics.

Left to Right:
Darcy Erickson, Manager, Drilling & Completions
John Keirle, Land Manager
Chris Edwards, Exploitation Engineer

Left to Right:
Darren Meszaros, Production Foreman
Jason Balogh, Operator
Southeast Saskatchewan

Harvest made two sizeable and strategically important acquisitions in 2004, both of which were accretive to cash flow, net asset value, production and reserves per unit. In June, Harvest acquired assets in North Central Alberta for $192.2 million, resulting in a production increase of 25% and the creation of a new core area. Shortly thereafter, we announced our largest transaction to date: a $511 million acquisition of assets in East Central and Southern Alberta. These transactions support Harvest's future sustainability by expanding our asset base with additional, high quality production and reserves, increasing our inventory of drilling and property enhancement projects, expanding our existing East Central core area, and creating a new core area in Southern Alberta. Development work on all of our new properties was initiated immediately, and remains a focal point for our 2005 capital program.

Going forward, Harvest will pursue opportunities to complete smaller acquisitions within our existing core areas, and continue to evaluate non-core asset dispositions by large conventional producers in Western Canada.

Capital Structure

Successful trusts are able to acquire, develop and manage assets, while accessing low-cost sources of capital to finance those activities. Harvest accomplishes this, in part, by retaining a portion of our cash flow for strengthening our balance sheet and reinvesting in our properties. If necessary, retained cash flow can be supplemented with external capital such as equity, or appropriate amounts of debt to finance acquisitions and development. In the fall of 2004, Harvest entered the U.S. capital markets with the issuance of U.S.$250 million of long-term senior notes, bearing interest at 7 7/8%. We anticipate this move will provide Harvest with a sizeable new source of long-term, low-cost capital that we can access to help fund our growth plans. We believe our capital structure is appropriate given our low payout ratio and strong risk management practices.

Left to Right:
John Mah, Sarbanes–Oxley Project Coordinator
Cindy Gray, Investor Relations and Communications
Danielle Gallant, Manager of Corporate Finance
Steve Saunders, Director of Taxation

John Noskey, Operator
North Central Alberta

Risk Management

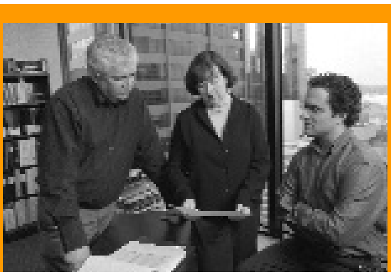
Harvest's risk management activities are designed to reduce the negative impact, where practical, of external factors on our operational and financial performance. Hedging is an important element of our strategy, designed to provide 'insurance' against extreme commodity price volatility. Harvest's approach to hedging has evolved through the use of different types of derivatives. For example, the derivative contracts in place through 2004 were primarily swaps, which secured a higher floor price, but did not allow much participation in strengthening crude oil price markets. The majority of these hedges expired at the end of 2004. For 2005 and 2006, a significant portion of Harvest's oil volumes are hedged using innovative derivative structures such as indexed puts. These structures provide us with confidence in our cash flows should oil prices decline below certain levels, but also provide us with the opportunity to participate in upward oil price movements.

The Power of People

Harvest's people are an integral part of our organization. We have assembled an experienced, skilled and committed team capable of evaluating, acquiring, optimizing and operating mature properties. From our independent Board of Directors to each individual employee, we are all dedicated to the ongoing success of Harvest.

Looking Ahead

We will continue to execute our strategy of maximizing the value of every barrel, while delivering stable distributions to Unitholders. In 2005, our capital development program will focus on low risk drilling, optimization and cost reduction activities which have proven effective in the past. We will continue building our inventory of property enhancement projects to provide for further development of our assets in the future. We will also pursue accretive acquisitions that meet our stringent criteria, and which expand our interests in existing core areas, or establish new core areas.



Left to Right:
Doug Johnston, Production Technologist
Karen Veenhuysen, Sr. Geologist
Brennan Ross, Production Technologist

Paul Cook, Instrument Technologist
Southern Alberta

In the context of the broader market, oil prices are expected to remain robust in 2005 and 2006, relative to historical levels. Heavy oil differentials and currency exchange rates appear to have stabilized at or near current levels. Through 2005, Harvest's crude oil and exchange rate hedges, as well as our U.S. dollar denominated senior notes, provide significant protection from oil price and currency movements. We have also hedged a significant portion of our crude oil volumes in 2006. As a result of these hedges and our low payout ratio, Harvest is well positioned to weather significant changes to commodity prices or other external uncertainties, while continuing to deliver reliable distributions.

In mid-April 2005, Harvest will distribute its 28th consecutive cash distribution of $0.20 per unit per month. We are committed to sustaining or increasing our monthly distributions.

We wish to thank every Harvest employee for their dedication, enthusiasm and tireless efforts. Each member of our valued team has contributed to Harvest's success. We also want to express our appreciation to our Unitholders for their continued support of Harvest's strategy and confidence in our vision. We look forward to reporting on our continued growth in 2005.

On behalf of Management

"Signed"

Jacob Roorda
President

March 24, 2005

Left to Right:
Dwight Gaab, Joint Interest Accounting Supervisor
Tracey Suchlandt, Accounts Payable Supervisor
Allan Post, Operational Controller
Kim Blauel, Production Accounting Manager

Operations Review

Victor Gette, Foreman
East Central Alberta

Harvest focuses on the operation of high quality, mature properties using a simple and straight forward approach. Harvest's value creation strategy involves acquiring under-managed, legacy properties with high working interests at reasonable prices and then employing hands-on management and diligent operational practices to extract maximum value.

Production optimization is a hallmark of Harvest's success and is achieved by controlling operating and power costs, as well as processing and disposal infrastructure, maintaining a dominant land position in our core areas, utilizing our expertise in fluid handling and encouraging our employees to think 'outside the box'. Harvest's unique marketing arrangements help to effectively enhance our cash flow.

Harvest has four core areas of operation: East Central Alberta, Southeast Saskatchewan, North Central Alberta and Southern Alberta.

	East Central Alberta	South East Saskatchewan	North Central Alberta	Southern Alberta	Total of All Areas
Production (1)					
Crude oil	13,378	5,496	3,166	8,219	30,259
Natural gas	3,098	271	702	23,626	27,697
NGL	62	78	160	566	866
Total BOE	13,956	5,619	3,443	12,723	35,741
Average WI (%)	85%-90%	98%	50%	85%	85%
Operatorship (%)	90%	99%	75%	100%	90%
Reserves (P+P)					
Crude oil (mmbbl)	34.9	17.5	9.7	23.9	86.0
Natural gas (bcf)	7.2	1.4	7.2	67.3	83.1
NGL (mmbbl)	0.2	0.3	0.4	1.7	2.6
Total BOE (mmBOE)	36.3	18.0	11.3	36.8	102.5
Operating costs ($/BOE) (1)	$ 9.09	$ 10.08	$ 5.08	$ 5.21	$ 7.49
Average royalty (%) (1)	13.2%	20.3%	20.5%	17.6%	16.7%

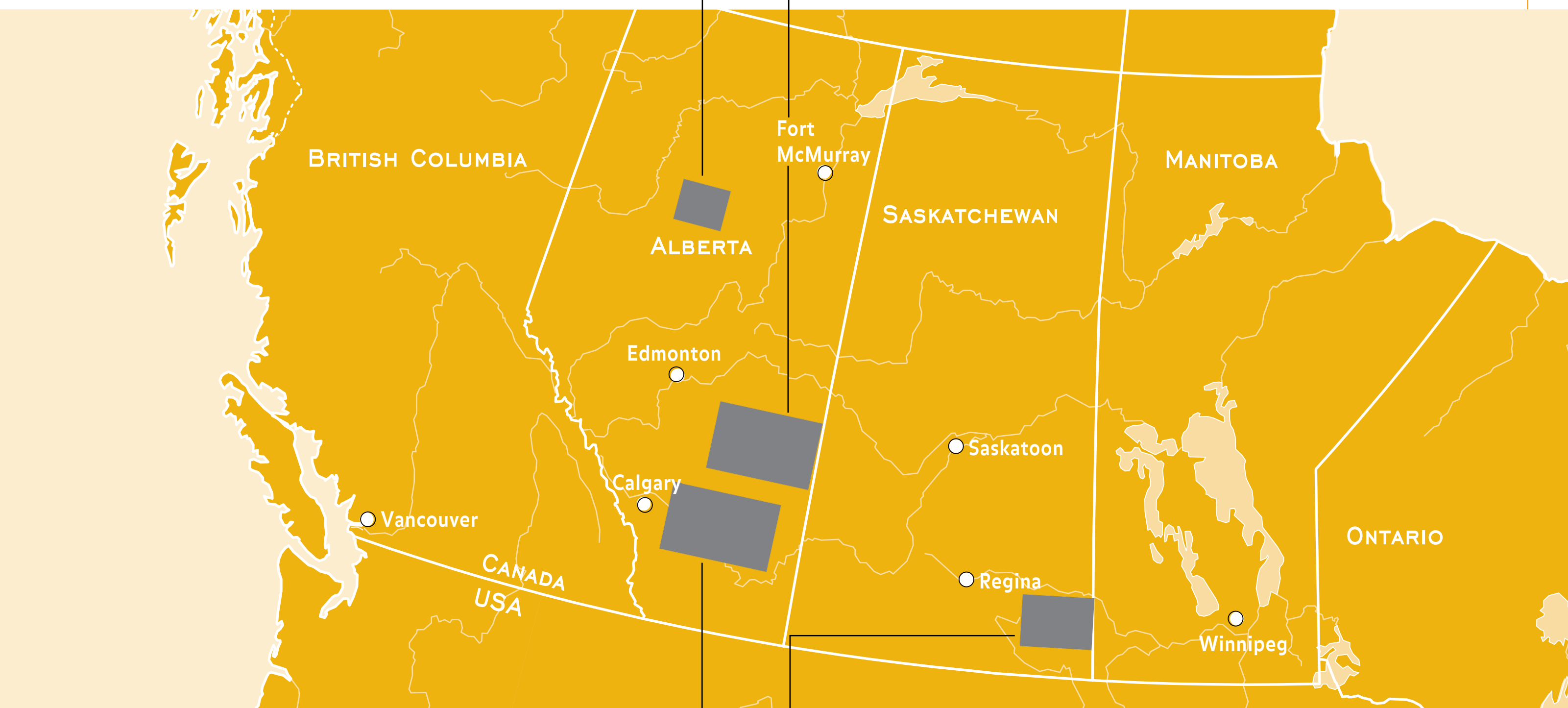
(1) Data as at March 2005.
Columns may not add due to rounding.

North Central Alberta

Kirk Low,
Operator

East Central Alberta

Rick Sather,
Operator



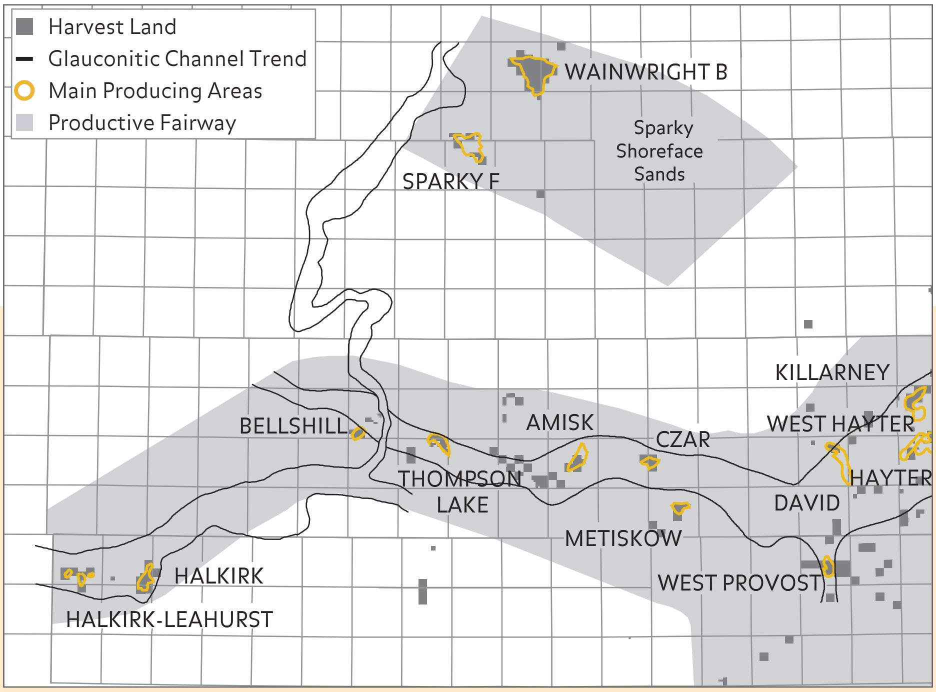
Southern Alberta

Craig Ryckman,
Operator

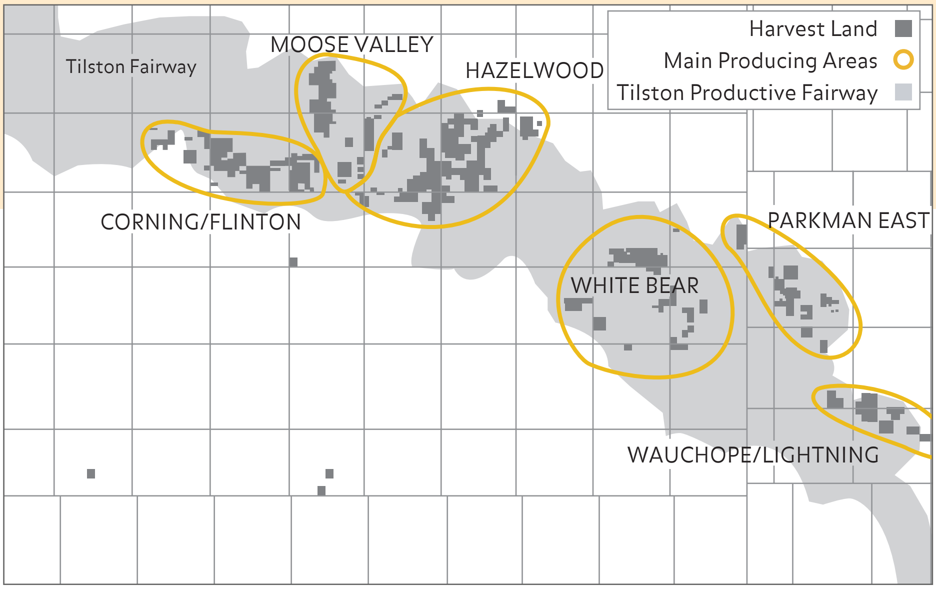
Southeast Saskatchewan

Darren Meszaros,
Production Foreman

East Central Alberta



Southeast Saskatchewan



Clinton James, Operator
East Central Alberta

East Central Alberta

Harvest's targeted entry into the East Central Alberta area was driven by strategy and an obvious value creation opportunity. The area has provided ongoing quality acquisition opportunities, as senior producers continue to turn their attention to natural gas opportunities located elsewhere. Harvest's East Central core area consists of 14 properties, which are currently producing approximately 14,000 BOE/d including the most recent additions which took place in September 2004. Situated along proven geological trends, these large, original oil-in-place fields offer superior reservoir quality, modern facilities and a history of reserve accretion. Harvest plans to continue with basic oil field fluid handling and production optimization, efficiency improvements, and operating cost reduction activities designed to expand cash flow and extend the reserve life, leading to further value creation in this area. Projects that are successful at one property can generally be applied to similar properties elsewhere with positive results.

Harvest focuses on efficient water handling and power reduction activities in East Central Alberta because a significant portion of the area's operating costs are power-related. Drilling low-pressure water disposal wells, plus the extensive use of power hedges, have significantly managed power costs in this area. As a result, Harvest has been successful in generating strong cash flows, high rates of return and quick paybacks.

Left to Right:
Aaron Lane, Area Engineer
Jason Kachur, Engineer
Randy Doetzel, Production Manager

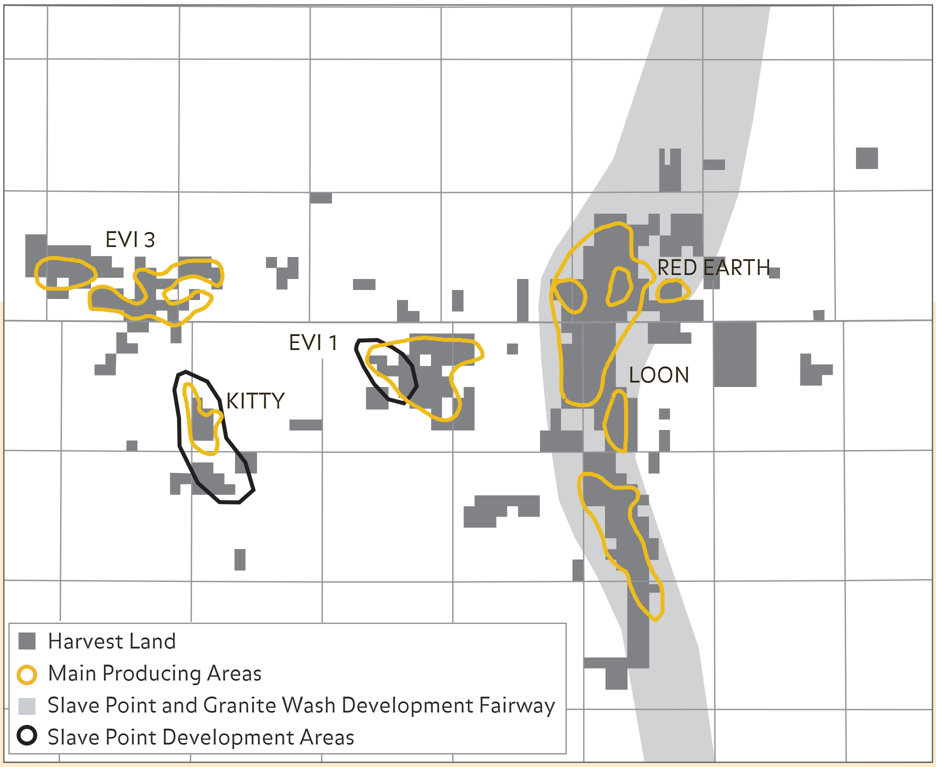
Southeast Saskatchewan

With the October 2003 acquisition of light crude oil assets in Southeast Saskatchewan, Harvest has demonstrated success in applying its exploitation and optimization expertise across different geographic areas, geological zones and product types. Harvest now dominates the Tilston trend in Southeast Saskatchewan, and has been able to apply operational techniques and concepts in this area that are similar to those used in East Central Alberta. Harvest's extensive proprietary 3-D seismic coverage also provides a strategic advantage for maintaining control of drilling opportunities and growing the area's production base.

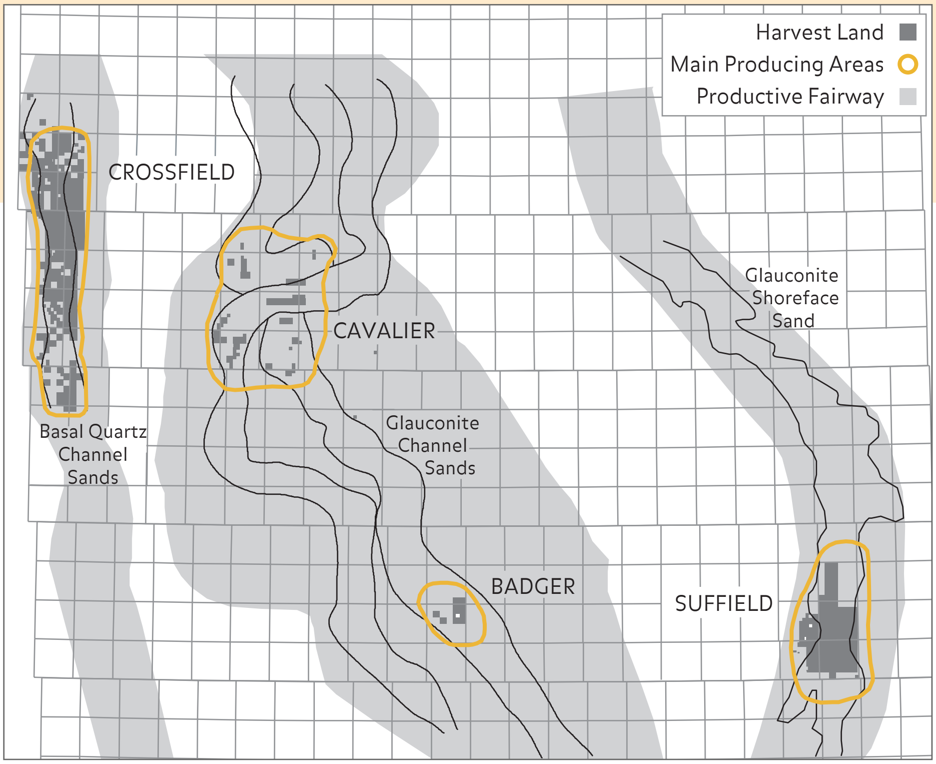
Production in Southeast Saskatchewan has increased from approximately 5,000 BOE/d in October 2003 to approximately 5,600 BOE/d currently, primarily due to Harvest's drilling and water handling efforts. Future development will include step-out and horizontal infill drilling to further exploit new pools and increase drainage and recovery factors. The high quality production, strategic control through area domination, and a deep inventory of development opportunities have contributed to Southeast Saskatchewan becoming a key asset within Harvest's portfolio.

Left to Right:
Dominic Brunel, Production Engineering Supervisor
Kristine Michie, Engineer
Jordy Brickner, Exploitation Engineer
Keely O'Neil, Landman

North Central Alberta



Southern Alberta



Larry Heck, Lead Operator
East Central Alberta

North Central Alberta

In June of 2004, Harvest acquired light oil properties located in the Red Earth region of North Central Alberta. These assets present a good value opportunity for Harvest as they offer high netbacks, stable production profiles, low operating expenses, a longer reserve life, and future development opportunities. We also see opportunities for future acquisitions in this area.

Harvest will target expanded waterflood and depletion of the underexploited Slave Point G pool and additional step-out or infill wells will target the prolific Granite Wash sands. Optimization projects such as injector well conversions, recompletions, and pump upgrades are budgeted to increase well productivity. Current production in the North Central area is approximately 3,400 BOE/d of high quality, light gravity crude oil from the Slave Point and Granite Wash formations.

Left to Right:
Derrick Jewlal, Reservoir/Evaluations Engineer
Gary Boukall, Chief Geologist
Matthew Mazuryk, Manager of Engineering
Stacia Skappak, Project Geologist

Southern Alberta

Harvest's Southern Alberta core area was formed following the acquisition of assets in September 2004. Properties in the area include Suffield, Crossfield, Badger and Cavalier, and at year-end 2004 were collectively producing approximately 12,700 BOE/d. Harvest realized further diversification of our product mix with the addition of our first significant natural gas production at Crossfield and Cavalier.

The area offers large accumulations of original-resource-in-place reservoirs situated along proven geological trends at Cavalier, Suffield and Crossfield. Exploitation and development strategies successfully employed in Harvest's East Central Alberta area and elsewhere can be applied in Southern Alberta. With numerous development and optimization opportunities, and a large drilling inventory, Southern Alberta will be a focal point for Harvest in 2005 and beyond.

Left to Right:
Kris Boehmer, Exploitation Engineer
Mark Lackie, Landman
Byron Cowley, Sr. Geologist

Reserves Disclosure

All of the evaluations and the data provided herein are in accordance with National Instrument 51-101, except where noted. McDaniel & Associates evaluated approximately 77% of the total reserves, primarily in Harvest's East Central and North Central Alberta properties. Gilbert Laustsen Jung Associates evaluated approximately 17% of Harvest's reserves, consisting of the new Southern Alberta properties acquired in September. Paddock Lindstrom & Associates evaluated approximately 6% of the total reserves, consisting of a portion of the North Central Alberta properties acquired in June, 2004. McDaniel's pricing forecasts were used in all reserve evaluations. The information and tables listed below constitute a summary of the three separate reserve reports. Further reserves information is available in Harvest's Annual Information Form filed on SEDAR and available on Harvest's website.

Reserves data presented below is net of abandonment costs.

Reserves Summary – Forecast Prices and Costs as at December 31, 2004

	Light and Medium Oil		Heavy Oil		Natural Gas Liquids	
Reserves Category	Gross (1) (mbbl)	Net (2) (mbbl)	Gross (1) (mbbl)	Net (2) (mbbl)	Gross (1) (mbbl)	Net (2) (mbbl)
Proved						
Developed Producing	26,385.8	23,679.3	29,355.3	26,635.9	1,979.5	1,755.4
Developed Non-Producing	356.6	331.9	–	–	82.2	72.0
Undeveloped	2,698.6	2,416.3	3,374.5	2,923.7	63.5	60.0
Total Proved	29,441.0	26,427.5	32,729.8	29,559.6	2,125.2	1,887.4
Probable	8,397.7	7,679.9	15,446.9	13,849.4	512.8	463.0
Total Proved plus Probable	37,838.7	34,107.4	48,176.7	43,409.0	2,638.0	2,350.4

	Natural Gas		Total Oil Equivalent (3)	
Reserves Category	Gross (1) (mmcf)	Net (2) (mmcf)	Gross (1) (mBOE)	Net (2) (mBOE)
Proved				
Developed Producing	56,887.4	50,464.8	67,201.8	60,481.4
Developed Non-Producing	5,649.7	5,426.3	1,380.4	1,308.3
Undeveloped	1,953.6	1,328.7	6,462.2	5,621.5
Total Proved	64,490.7	57,219.8	75,044.5	67,411.1
Probable	18,660.2	16,474.6	27,467.4	24,738.1
Total Proved plus Probable	83,150.9	73,694.4	102,511.9	92,149.2

(1) "Gross" reserves means the total working and royalty 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) Oil equivalent amounts 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.

2004 Reserve Life Index

Harvest calculates its reserve life index by dividing the total reserves by the forecast 2005 production for that category as reported in the reserve engineer's evaluation report.

Proved Producing:	5.7
Total Proved:	6.2
Total Proved plus Probable:	7.9

Net Present Value of Reserves – Forecast Prices and Costs as at December 31, 2004

	Net Present Values of Future Net Revenue, Before Income Taxes, Discounted at (%/year)[1]				
Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
Proved					
Developed Producing	1,145,401.6	948,487.3	820,000.6	728,640.9	659,768.4
Developed Non-Producing	35,851.3	25,399.5	19,697.4	16,136.0	13,691.1
Undeveloped	103,879.8	77,550.3	60,364.4	48,400.8	39,649.2
Total Proved	1,285,132.7	1,051,437.1	900,062.4	793,177.7	713,108.7
Probable	447,590.0	310,111.9	232,424.1	183,027.1	149,083.9
Total Proved Plus Probable	1,732,722.7	1,361,549.0	1,132,486.5	976,204.8	862,192.6

Notes to Reserves Data Tables:

(1) The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid and payable to Unitholders in the course of the most recent financial year, the Trust is not liable for any material amount of income tax on income. The net present values of future net revenue after income taxes are, therefore, the same as the net present values of future net revenue before income taxes.

(2) Columns may not add due to rounding.

(3) The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook.

2004 Reconciliation of Gross Reserves by Principal Product Type using Forecast Prices and Costs as at December 31, 2004

	Total Proved				Proved plus Probable				Total Proved	Proved plus Probable
	Oil (mbbl)	Heavy Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Oil (mbbl)	Heavy Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	(mBOE)	(mBOE)
Dec. 31/03	19,252	7,511	1,988	122	23,869	8,564	2,699	154	27,216	33,037
Revisions	3,741	1,572	1,281	258	4,062	2,179	1,818	319	5,784	6,862
New adds	1,405	162	52	–	2,159	189	64	–	1,576	2,358
Acquisitions	9,521	26,594	65,161	1,917	12,227	40,354	82,561	2,337	48,893	68,679
Dispositions	–	–	–	–	–	–	–	–	–	–
Production	(4,478)	(3,109)	(3,991)	(172)	(4,478)	(3,109)	(3,991)	(172)	(8,424)	(8,424)
Dec. 31/04	**29,441**	**32,730**	**64,491**	**2,125**	**37,839**	**48,177**	**83,151**	**2,638**	**75,044**	**102,512**

Note:
A 2004 reconciliation of net reserves, compliant with NI 51-101, is available in Harvest's 2004 Annual Information Form filed on SEDAR.

Summary of McDaniel & Associates Consultants Ltd.
Pricing and Inflation Rate Assumptions as of January 1, 2005
Forecast Prices and Costs

	Oil								
Year	WTI Crude Oil ($U.S./bbl)	Edmonton Light Crude Oil ($/bbl)	Alberta Heavy Crude Oil ($/bbl)	Alberta Bow River Medium Crude Oil ($/bbl)	Sask. Cromer Medium Crude Oil ($/bbl)	Natural Gas Alberta AECO Spot Price ($/GJ)	Natural Gas Liquids Edmonton Condensate & Natural Gas ($/bbl)	Inflation Rates (%/year)	U.S./CDA Exchange Rate ($Cdn/$U.S.)
Forecast									
2005	42.00	49.60	29.40	37.00	43.50	6.45	50.40	2.0	0.830
2006	39.50	46.60	29.90	37.10	40.90	6.20	47.40	2.0	0.830
2007	37.00	43.50	27.90	34.60	38.20	6.05	44.30	2.0	0.830
2008	35.00	41.10	26.30	32.70	36.00	5.80	41.90	2.0	0.830
2009	34.50	40.50	25.90	32.20	35.50	5.70	41.30	2.0	0.830

Finding and Development (F&D) Costs

	Total Proved		Proved plus Probable	
	2004	2003	**2004**	2003
Development capital expenditures ($000s)	**42,662**	27,209	**42,662**	27,209
Net change from previous year's future development capital ($000s)	**(2,784)**	5,372	**(4,407)**	21,601
Total capital including net change in future development capital ($000s)	**39,878**	32,581	**38,255**	48,810
Reserves additions (mBOE)	**7,360**	4,207	**9,220**	2,684
F&D cost ($/BOE)	**$ 5.42**	$ 12.14	**$ 4.15**	$ 11.60

Finding, Development and Acquisition (FD&A) Costs

	Total Proved		Proved plus Probable	
	2004	2003	**2004**	2003
Including effect of acquisitions				
Capital expenditures ($000s)	**748,662**	135,900	**748,662**	135,900
Net change from previous year's future development capital ($000s)	**67,865**	5,372	**114,566**	21,601
Total capital including net change in future development capital ($000s)	**816,527**	141,272	**863,228**	157,901
Reserve additions (mBOE)	**56,252**	19,458	**77,900**	23,702
FD&A cost ($/BOE)	**$ 14.51**	$ 7.26	**$ 11.08**	$ 6.65

Reserve Recycle Ratio Calculation

	Total Proved		Proved plus Probable	
	2004	2003	**2004**	2003
Average field netback, before realized losses on derivative contracts ($/BOE)	**$ 24.17**	$ 16.22	**$ 24.17**	$ 16.22
F&D cost ($/BOE)	**$ 5.42**	$ 12.14	**$ 4.15**	$ 11.60
F&D reserve recycle ratio	**4.5**	1.3	**5.8**	1.4
FD&A cost ($/BOE)	**$ 14.51**	$ 7.26	**$ 11.08**	$ 6.65
FD&A reserve recycle ratio	**1.7**	2.2	**2.2**	2.4

Corporate Governance

Harvest recognizes the importance of sound corporate governance. We are committed to conducting all of our affairs based on a foundation of trust, integrity and ethical behavior. As stewards of the Trust, the Board of Directors and senior executive team are capable and empowered to ensure that the interests of all stakeholders are appropriately balanced against the strategies and over-arching principles of the Trust.

Strong corporate governance is much more than a set of rules to follow; it is the foundation of our business and a key to enhancing the performance of the Trust.

Harvest's corporate structure and governance principles have been designed to ensure that Unitholders' interests are addressed while maintaining structural simplicity, transparency, and aligned interests. The Board consists of independent, non-executive directors, all of whom have extensive industry experience. Four specific Board committees have been established to ensure maximum efficiency and effectiveness: the Audit Committee, the Corporate Governance Committee, the Compensation Committee, and the Reserves, Safety and Environment Committee. Each committee includes directors who possess the relevant skills and knowledge needed to execute the committee's mandate.

As the corporate and regulatory landscape continues to change, Harvest's corporate governance practices will grow and evolve accordingly. We currently comply with the existing corporate governance guidelines for Canadian issuers. Nevertheless we are committed to evolve 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 plans 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.

Left to Right:
Kelly Doka, Operator
Robert Lyons, Lead Operator
Jack Soloshy, Production Foreman
Southeast Saskatchewan

Sustainable Development

> Harvest is committed to sustainable development and to meeting the highest possible standards of care for the environment, the health and safety of our employees and residents of communities in which we operate.

As operators of mature oil and natural gas properties, 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.

As part of our Stewardship initiative, Harvest maintains internally-developed management programs to deal with environmental, abandonment and reclamation issues, which are funded on an ongoing basis as required. These programs are directed by dedicated professionals who have the relevant regulatory and compliance expertise, and can help us to better understand the abandonment and site reclamation responsibilities for each of our properties. We identify potential deficiencies in our operations via field tours and well file reviews, and have implemented a Compliance Tracker Program to provide ongoing status reports on the Trust's overall compliance with environmental, health, safety, and regulatory requirements.

Harvest's positive safety record reflects our commitment to training and building the knowledge base of our employees and our genuine concern for their safety and well-being. In 2004, Harvest's management implemented an Award of Excellence program to recognize field staff who excel in integrating the concepts of environmental responsibility, regulatory compliance, and health and safety into our everyday business.

Harvest is a member of the Canadian Association of Petroleum Producers (CAPP) and is enrolled at a platinum level status under CAPP's Stewardship program. This means we will conduct regular compliance audits of our safety program, and will track and monitor our Green House Gas (GHG) emissions as part of our Stewardship process.

Harvest realizes that our impact extends beyond the field or the boardroom, and we strive to make a positive impact on communities in which we are active. Consistent with the premise of sustainable development, we truly believe that we can meet the needs of today without impeding future generations from meeting their own needs.

Craig Ryckman, Operator
Southern Alberta

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 year ended December 31, 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 24, 2005.

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") 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.

Certain Financial Reporting Measures

We use certain financial reporting measures that are commonly used as benchmarks within the oil and natural gas industry. These measures include: "Cash Flow from Operations", "Net Debt", "Payout Ratio", "Net Operating Income" and "Operating Netbacks". 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.

Specifically, management uses Cash Flow from Operations as cash flow from operating activities before changes in non-cash working capital and settlement of asset retirement obligations. Under GAAP, this measure is defined as funds flow, and the accepted definition of cash flow from operating activities is net of changes in non-cash working capital and settlement of asset retirement obligations. Cash Flow from Operations 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 believes our usage of Cash Flow from Operations is a better indicator of our ability to generate cash flows from future operations. Net Debt, Payout Ratio, Net Operating Income, and Operating Netbacks are additional non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Net Debt includes total debt outstanding, any working capital deficit, the face value of convertible debentures outstanding, and equity bridge notes. (Note: for accounting purposes in 2004, convertible debentures and equity bridge notes were classified as equity and not debt. In 2005, accounting rule changes will result in these amounts being presented as debt.). Payout Ratio is the ratio of distributions to total Cash Flow from Operations. Net Operating Income is net revenue (gross revenue less royalties) less operating expenses. 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 derivative contracts.

Forward-Looking Information

This MD&A contains forward-looking statements. These statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those included in the forward-looking statements. The words "believe," "expect," "intend," "estimate" or "anticipate" and similar expressions, as well as future or conditional verbs such as "will," "should," "would," and "could" often identify forward-looking statements. Specific forward-looking statements contained in this MD&A include, among others, statements regarding our:

- expected financial performance in future periods;
- expected increases in revenue attributable to its development and production activities;

- estimated capital expenditures for fiscal 2005 and subsequent periods;
- competitive advantages and ability to compete successfully;
- intention to continue adding value through drilling and exploitation activities;
- emphasis on having a low cost structure;
- intention to retain a portion of our cash flows after distributions to repay indebtedness and invest in further development of our properties;
- reserve estimates and estimates of the present value of our future net cash flows;
- methods of raising capital for exploitation and development of reserves;
- factors upon which we will decide whether or not to undertake a development or exploitation project;
- plans to make acquisitions and expected synergies from acquisitions made;
- expectations regarding the development and production potential of our properties; and
- treatment under government regulatory regimes.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things:
- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- the cost of expanding our property holdings;
- our ability to obtain equipment in a timely manner to carry out development activities;
- our ability to market oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and exploitation activities.

Some of the risks that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:
- the volatility of oil and natural gas prices, including the differential between the price of light, medium and heavy oil;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- difficulties encountered during the drilling for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- foreign currency fluctuations;
- the uncertainty of our ability to attract capital;
- changes in, or the introduction of, new government regulations relating to the oil and natural gas business;
- costs associated with developing and producing oil and natural gas;
- compliance with environmental regulations;
- liabilities stemming from accidental damage to the environment;
- loss of the services of any of our senior management or directors; and
- adverse changes in the economy generally.

The information contained in this MD&A, including the information provided under the heading “Operational and Other Business Risks” identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.

Our forward-looking statements are expressly qualified in their entirety by this cautionary statement. Our forward-looking statements are only made as of the date of this MD&A and we undertake no obligation to publicly update these forward-looking statements to reflect new information, subsequent events or otherwise.

Overview and Strategy

Harvest Energy Trust is an oil and natural gas royalty trust, which focuses on the operation of high quality mature properties. We have operations in four core areas: North Central Alberta, East Central Alberta, Southern Alberta and Southeast Saskatchewan.

Since inception, we have followed a strategy designed for sustainability. We retain significant cash flows for reinvestment, and focus on realizing per Unit accretion in reserves, production, cash flow and net asset value when reviewing potential acquisitions and capital projects.

2004 Financial and Operating Highlights

The table below provides a summary of our financial and operating results for both the three and twelve month periods ended December 31, 2004 and 2003. Readers should note that the fourth quarter of 2004 was the first full operating quarter that included production from both of the significant acquisitions completed in 2004. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Three Months Ended December 31			Twelve Months Ended December 31		
($000s, except where noted)	**2004**	2003	% Change	**2004**	2003	% Change
		(Restated) (6)			*(Restated)* (6)	
Financial						
Revenue, net of royalties	**107,446**	33,575	220%	**277,095**	102,939	169%
Cash flow from operations (5)	**53,545**	13,699	291%	**130,003**	46,492	180%
Per Trust Unit, basic (5)	**$ 1.31**	$ 0.85	54%	**$ 5.13**	$ 3.69	39%
Per Trust Unit, diluted (5)	**$ 1.27**	$ 0.82	55%	**$ 4.91**	$ 3.58	37%
Net income	**12,536**	5,495	128%	**18,231**	15,516	17%
Per Trust Unit, basic	**$ 0.29**	$ 0.30	(3%)	**$ 0.47**	$ 1.16	(59%)
Per Trust Unit, diluted	**$ 0.28**	$ 0.29	(3%)	**$ 0.45**	$ 1.13	(60%)
Distributions, declared	**24,823**	10,209	143%	**64,563**	30,685	110%
Distributions per Trust Unit, declared (7)	**$ 0.60**	$ 0.60	0%	**$ 2.40**	$ 2.40	0%
Payout ratio (2) (5)	**46%**	75%	(39%)	**50%**	66%	(24%)
Capital asset additions (excluding acquisitions)	**8,873**	4,334	105%	**42,662**	27,209	57%
Acquisitions	**–**	80,271	(100%)	**706,000**	108,700	549%
Net debt (excluding derivative contracts) (3) (5)	**429,671**	78,555	447%	**429,671**	78,555	447%
Weighted average Trust Units outstanding, basic (4)	**40,937**	16,175	153%	**25,324**	12,591	101%
Trust Units outstanding, end of period	**41,788**	17,109	144%	**41,788**	17,109	144%
Trust Units, fully diluted (8), end of period	**45,088**	18,174	148%	**45,088**	18,174	148%
Operating						
Daily sales volumes (10)						
Light oil (bbl/d)	**12,228**	4,079	200%	**7,911**	1,028	670%
Medium oil (bbl/d)	**3,644**	4,662	(22%)	**4,324**	4,286	1%
Heavy oil (bbl/d)	**15,120**	5,756	163%	**8,495**	5,444	56%
Natural gas liquids (bbl/d)	**1,309**	70	1770%	**471**	64	636%
Natural gas (mcf/d)	**28,338**	1,744	1525%	**10,903**	1,311	732%
Total (BOE/d) (1)	**37,024**	14,858	149%	**23,019**	11,040	109%
Operating netback (5) ($/BOE)						
Revenues	**37.77**	29.13	30%	**39.33**	29.62	33%
Realized loss on derivative contracts	**(4.91)**	(2.18)	125%	**(6.47)**	(4.67)	39%
Royalties	**(6.23)**	(4.66)	34%	**(6.44)**	(4.07)	58%
Operating expense (9)	**(7.37)**	(9.50)	(22%)	**(8.48)**	(8.94)	(5%)
Operating netback (5)	**19.26**	12.79	51%	**17.94**	11.94	50%

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6 mcf of natural gas to 1 barrel of crude oil. BOEs may be misleading, particularly if used in isolation. The BOE 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.

(2) Ratio of distributions to cash flow from operations.

(3) Net debt is bank debt, senior notes, equity bridge notes, convertible debentures and any working capital deficit excluding the current portion of derivative contracts and the accounting liability related to our Trust Unit incentive plan. Equity bridge notes and convertible debentures are reflected as equity on our consolidated balance sheet in accordance with Canadian GAAP. In 2005, GAPP will require these amounts to be reflected as debt.

(4) Reflects both Trust Units and exchangeable shares.

(5) These are non-GAAP measures; please refer to "Certain Financial Reporting Measures" in this MD&A.

(6) Restated to reflect the adoption of new CICA recommendations to account for asset retirement obligations. See Note 3 to the Consolidated Financial Statements.

(7) As if the Trust Unit was held throughout the period in 2003.

(8) Fully diluted units differ from diluted units for accounting purposes. Fully diluted includes Trust Units outstanding as at December 31 plus the impact of the conversion of exercise of exchangeable shares, Trust Unit rights and convertible debentures if completed at December 31.

(9) Includes realized gain on electricity derivative contracts of $0.18 and $0.24 for fourth quarter and full year 2004, respectively, and $0.26 and $0.39 for the same periods in 2003.

(10) Harvest classifies its oil production as light, medium and heavy according to NI 51-101 guidance.

2004 Highlights

When reviewing our 2004 results, readers are reminded that the Storm acquisition took place on June 30, 2004, and the EnCana acquisition became effective on September 2, 2004. The combination of these two events significantly impacted our operations and financial results for the latter part of 2004 as well as comparability between quarters.

- The Storm acquisition represented approximately 4,000 BOE/d of light oil and natural gas properties in the Red Earth area of North Central Alberta, for consideration of $192.2 million;
- The EnCana acquisition of $526 million ($511.4 million after adjustments) for properties in East Central and Southern Alberta added approximately 19,000 BOE/d of production. Additionally, our reserve life index increased to 8 and we diversified our product mix by increasing our natural gas production weighting to approximately 13%;
- We successfully closed a financing of U.S.$250 million, 7-year 7 7/8% senior notes on October 14, 2004 creating additional financial flexibility and providing entry into the U.S. financial markets. The proceeds from the financing were used to substantially repay outstanding bank debt used to finance the EnCana acquisition;
- We have successfully integrated the new North Central, East Central and Southern Alberta personnel and assets into our existing operations. Development and optimization work on all properties commenced immediately after the closing of each transaction.

2004 Benchmark Performance and 2005 Outlook

The table below provides a summary of our performance during 2004 against objectives identified in our 2003 annual report, and outlines our objectives for 2005.

2004 Objective	2004 Performance	2005 Outlook
Build on success achieved in 2003 by adding proved reserves and extending reserve life index (RLI).	Through our internal capital development program, increased Total Proved reserves by 7.4 mmBOE, after adjusting for production. Corporate RLI extended to 8 years through development and acquisition.	Continue to develop and maximize returns from our assets.
Execute on accretive acquisitions that offer strategic fit, cost reductions, and improvement of portfolio quality.	Completed Storm acquisition in June, increasing production at that time to approximately 19,000 BOE/d and RLI to 6.7. High netback production and light oil added to asset mix. Completed EnCana acquisition in September, increasing production in the fourth quarter to average approximately 37,000 BOE/d. High netback production and natural gas added to asset portfolio.	Continue to evaluate acquisition opportunities, and capitalize on those where value can be added. If acquisition market is not accessible, exploit existing inventory of opportunities for development.
Invest $35 million of capital in development program.	Invested approximately $43 million in development capital through the year, recording Proved plus Probable Finding & Development (F&D) costs of $4.15/BOE and Total Proved F&D costs of $5.42/BOE.	Invest approximately $75 million in capital development.

2004 Objective	2004 Performance	2005 Outlook
Maintain average production between 15,000 and 15,500 BOE/d.	2004 production averaged 23,019 BOE/d; fourth quarter 2004 production averaged 37,024 BOE/d.	Production to average between 34,000 and 36,000 BOE/d.
Attain average royalty rate between 15 and 17% and operating expense per BOE between $10.00 and $10.50.	2004 royalty rate averaged 16.4%, while operating expenses per BOE averaged approximately $8.48 for the full year and $7.37 in the fourth quarter.	Maintain average royalty rate between 15 and 17%, and maintain operating expenses per BOE between $7.75 and $8.50.
Pay $0.20 per Unit per month distribution through 2004.	2004 distributions totaled $2.40 per Trust Unit.	Maintain consistent $0.20 distribution level through 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.

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
($000s, except per Trust Unit amounts)					*(Restated – Refer to Note 3 of the Consolidated Financial Statements)*			
Financial								
Revenue, net of royalties	**$ 107,446**	**$ 85,424**	**$ 44,752**	**$ 39,473**	$ 33,575	$ 24,706	$ 21,350	$ 23,308
Operating expense [3]	**(25,113)**	**(18,993)**	**(13,600)**	**(13,674)**	(12,984)	(9,661)	(6,596)	(6,804)
Net operating income [1]	**$ 82,333**	**$ 66,431**	**$ 31,152**	**$ 25,799**	$ 20,591	$ 15,045	$ 14,754	$ 16,504
Net income (loss)	**$ 12,536**	**$ 5,166**	**$ 1,594**	**$ (1,065)**	$ 5,495	$ 5,488	$ 1,064	$ 3,469
Per Trust Unit, basic [2]	**0.29**	**0.07**	**0.02**	**(0.13)**	0.30	0.44	0.09	0.33
Per Trust Unit, diluted [2]	**0.28**	**0.07**	**0.02**	**(0.13)**	0.29	0.43	0.09	0.32
Cash flow from operations [1]	**$ 53,545**	**$ 44,459**	**$ 17,160**	**$ 14,839**	$ 13,699	$ 16,758	$ 9,546	$ 6,489
Per Trust Unit, basic [1][2]	**1.31**	**1.50**	**0.99**	**0.87**	0.85	1.35	0.84	0.62
Per Trust Unit, diluted [1][2]	**1.27**	**1.47**	**0.96**	**0.84**	0.82	1.31	0.82	0.60
Sales volumes								
Crude oil (bbl/d)	**30,992**	**22,397**	**14,775**	**14,626**	14,497	11,054	9,371	8,034
Natural gas liquids (bbl/d)	**1,309**	**377**	**141**	**50**	70	77	67	43
Natural gas (mcf/d)	**28,338**	**11,909**	**2,249**	**915**	1,744	1,453	1,161	875
Total (BOE/d)	**37,024**	**24,759**	**15,291**	**14,829**	14,858	11,373	9,632	8,223

(1) This is a non-GAAP measure as referred to under "Certain Financial Reporting 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.

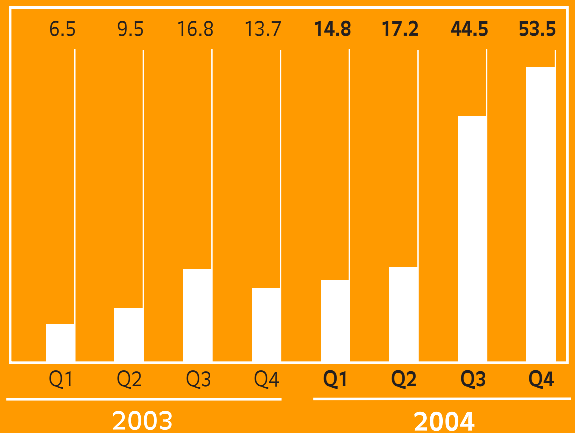
(3) Reflects the gains and losses on electricity derivative contracts.

Net revenues and net operating income have trended higher since the first quarter of 2003, with significant increases occurring in the third and fourth quarters of 2004. The revenue increase since 2003 is primarily attributable to increasing production volumes and the strong commodity price environment during 2004. The two significant acquisitions completed in 2004, which closed in June and September, both contributed to the significant increases in third and fourth quarter production volumes, revenue and cash flow.

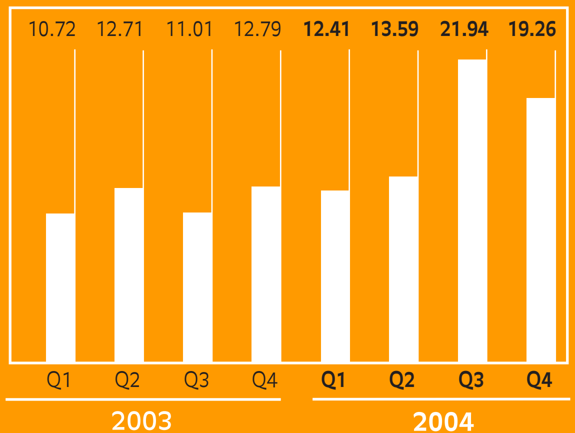
Net income reflects both cash and non-cash items. The non-cash items, including depletion, depreciation and accretion (DD&A), foreign exchange, unrealized gain or loss on derivatives, Trust Unit right compensation expense and future income taxes can cause net income to vary significantly. However, these items do not impact the cash flow available for distribution to Unitholders, and therefore management believes net income may be a less meaningful measure of performance for a royalty trust such as Harvest. Net income (loss) has not reflected the same trend as net revenues or cash flows due mainly to the inclusion of unrealized mark-to-market gains and losses on derivative contracts.

Cash flow from operations is a key measure for a royalty trust as it represents the key source of cash distributions for Unitholders. Excluding the substantial non-recurring foreign exchange gain realized in the third quarter of 2003, our cash flow from operations has demonstrated a steady upward trend. Cash flows can be impacted by factors outside of management's control such as commodity prices and currency exchange rates. We strive to mitigate the impact of these factors by using hedging (sometimes referred to as 'derivatives' or 'derivative contracts' herein) to fix future commodity prices and currency exchange rates on a portion of our transactions.

Cash Flow from Operations
($ millions)



Operating Netback*
($/BOE)



* Including gains/losses on derivatives.

Summary of Historical Annual Results

($ millions, except per Trust Unit amounts)

	Year Ended December 31		
	2004	2003	2002
		(Restated)	*(Restated)*
Net revenue	**$ 277.1**	$ 102.9	$ 20.0
Net income	**18.2**	15.5	4.8
Per Trust Unit, basic	**0.47**	1.16	3.47
Per Trust Unit, fully diluted	**0.45**	1.13	3.27
Total assets	**1,046.3**	256.4	108.4
Total long-term financial liabilities	**300.5**	–	–
Distributions per Unit, declared ($/Unit)	**$ 2.40**	$ 2.40	$ 0.20

Revenues	Three Months Ended December 31			Year Ended December 31		
	2004	2003	% Change	**2004**	2003	% Change
Oil and natural gas sales ($/BOE)	**$ 37.77**	$ 29.13	30%	**$ 39.33**	$ 29.62	33%
Royalty expense, net ($/BOE)	**(6.23)**	(4.66)	34%	**(6.44)**	(4.07)	58%
Net revenues ($/BOE)	**$ 31.54**	$ 24.47	29%	**$ 32.89**	$ 25.55	29%
Net revenues ($ millions)	**$ 107.4**	$ 33.6	220%	**$ 277.1**	$ 102.9	169%

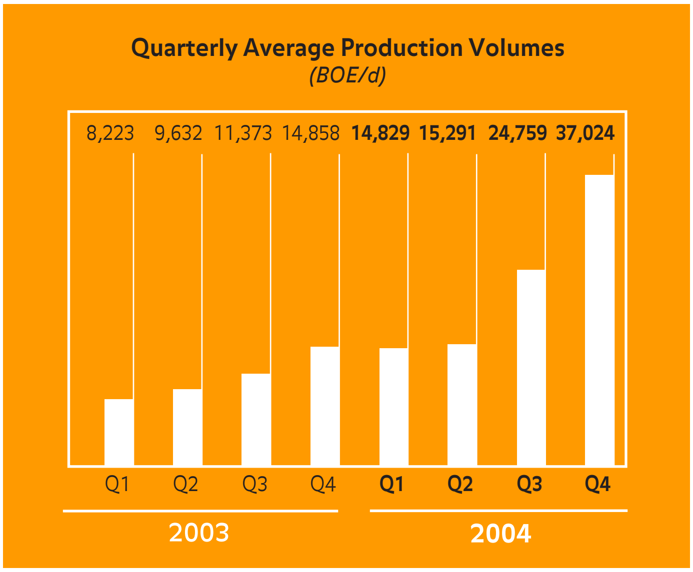
Our net revenue is impacted by production volumes, commodity prices, currency exchange rates and royalty rates. As a result of the acquisitions we completed during 2004, and the rising crude oil price environment, our revenues in the three and twelve month periods ending December 31, 2004 increased substantially over the same periods in 2003. Despite this, the increases in our fourth quarter 2004 revenues were slightly offset by widening heavy oil differentials, and a strengthening Canadian dollar. Changes in realized prices, volumes and royalty rates are discussed below. The impact of our hedging activities on current and future results is discussed under "Derivative Contracts".

Sales Volumes

The average daily sales volumes by product were as follows:

	Three Months Ended December 31			Year Ended December 31		
	2004	2003	% Change	**2004**	2003	% Change
Light oil (bbl/d)	**12,228**	4,079	200%	**7,911**	1,028	670%
Medium oil (bbl/d)	**3,644**	4,662	(22%)	**4,324**	4,286	1%
Heavy oil (bbl/d)	**15,120**	5,756	163%	**8,495**	5,444	56%
Total oil (bbl/d)	**30,992**	14,497	114%	**20,730**	10,758	93%
Natural gas liquids (bbl/d)	**1,309**	70	1,770%	**471**	64	636%
Total liquids (bbl/d)	**32,301**	14,567	122%	**21,201**	10,822	96%
Natural gas (mcf/d)	**28,338**	1,744	1,525%	**10,903**	1,311	732%
Total oil equivalent (BOE/d)	**37,024**	14,858	149%	**23,019**	11,040	109%

Sales volumes averaged 37,024 BOE/d in the fourth quarter of 2004, compared to 14,858 BOE/d for the same period in 2003. The fourth quarter production breakdown is representative of our new commodity mix following the Storm and EnCana transactions.



Full year 2004 average production of 23,019 BOE/d was 109% higher than the 11,040 BOE/d averaged in 2003. The higher average production realized in 2004 compared to 2003 is primarily attributable to the two significant acquisitions of Storm and the EnCana properties. In addition, the natural gas component of our production was approximately 13% in the fourth quarter, up from only 2% in the fourth quarter of 2003. In October 2003, we acquired approximately 5,500 BOE/d of production, the full impact of which was not realized until 2004.

For 2005, we anticipate production volumes to average between 34,000 and 36,000 BOE/day.

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. The product mix changed significantly in 2004 with the addition of light oil from the Storm acquisition and natural gas from the EnCana acquisition.

Realized Commodity Prices

The following table provides a breakdown of our 2004 and 2003 average commodity prices by product before realized losses on derivative contracts.

	Three Months Ended December 31			Year Ended December 31		
Product Prices	**2004**	2003	% Change	**2004**	2003	% Change
Light oil ($/bbl)	**$ 53.64**	$ 35.56	51%	**$ 48.70**	$ 35.56	37%
Medium oil ($/bbl)	**35.55**	30.13	18%	**38.78**	32.18	21%
Heavy oil ($/bbl)	**28.73**	24.92	15%	**31.11**	27.34	14%
Natural gas liquids ($/bbl)	**33.19**	29.18	14%	**41.10**	29.92	37%
Natural gas ($/mcf)	**5.68**	6.01	(5%)	**6.30**	6.70	(6%)
Total ($/BOE)	**$ 37.77**	$ 29.13	30%	**$ 39.33**	$ 29.62	33%
Realized derivative contract losses ($/BOE) (1)	**$ (4.91)**	$ (2.18)	125%	**$ (6.47)**	$ (4.67)	39%
Net realized price ($/BOE)	**$ 32.86**	$ 26.95	22%	**$ 32.86**	$ 24.95	32%

(1) These amounts are included in gains and losses on derivative contracts on the income statement.

In 2004, our revenues were impacted by realized losses on oil price swaps and collars that were implemented in 2002 and 2003. These hedge contracts capped our ability to realize upside on West Texas Intermediate ("WTI") price movements. The majority of these types of oil price derivative contracts expired at the end of 2004. Consequently, we will be able to realize net prices closer to spot price levels in 2005. At the time of writing, we had entered into oil price derivative contracts on approximately 75% of our 2005 net crude oil production, and approximately 40% of our 2006 net crude oil production. The majority of the 2005 and 2006 commodity derivative contracts that we have in place provide a fixed crude oil floor price, while retaining the ability to participate in upward price appreciation. Examples of such contracts include 'indexed puts' and 'participating swaps', and additional information on these and other commodity derivative contracts can be found in the "Derivative Contracts" section of this MD&A.

	Three Months Ended December 31			Year Ended December 31		
Benchmarks	**2004**	2003	% Change	**2004**	2003	% Change
WTI crude oil (U.S.$/bbl)	**$ 48.28**	$ 31.18	54.8%	**$ 41.40**	$ 30.99	33.6%
Edmonton Light crude oil ($/bbl)	**58.58**	41.05	42.7%	**53.20**	43.77	21.5%
Lloyd Blend crude oil ($/bbl)	**35.00**	27.31	28.2%	**36.30**	31.48	15.3%
Bow River Blend crude oil ($/bbl)	**35.66**	28.17	26.6%	**37.19**	32.39	14.8%
AECO natural gas ($/mcf)	**7.51**	5.96	26.0%	**6.80**	6.67	1.9%
Canadian / U.S. dollar exchange rate	**0.819**	0.760	7.8%	**0.770**	0.713	8.0%

Through 2004, the benchmark price of WTI crude oil rose steadily, opening the year at U.S.$32.40, hitting a high of U.S.$55.67 on October 25th, and closing the year at U.S.$43.45. These historically high prices for crude oil can be attributed to strong demand growth, particularly in China, and economic expansion in the U.S. OPEC was slow to respond to the demand increases and worldwide inventories dropped to near all-time lows measured by days of demand cover. This increased demand on OPEC left the cartel with little room for spare capacity, which caused further uncertainty and extreme price volatility. This tight supply/demand balance was compounded by continued unrest in the Middle East, fears of terrorism interrupting the supply chain, and concerns regarding tight refining capacity. In 2005, we anticipate these strong global fundamentals to be sustained, resulting in another robust environment for WTI prices. However, we see the potential for periods of weakness and the possibility for reduced economic growth in key demand markets such as the U.S. having a more serious impact on world oil prices.

Given Harvest's production mix, which includes medium and heavy crude oil, the benefits of high WTI prices were tempered due to wider medium and heavy crude price differentials in 2004. Heavy differentials reached a high in the fourth quarter of U.S.$19.79 per barrel below WTI for Lloyd Blend crude, a benchmark for medium and heavy crude oil prices in Western Canada. In an environment of rising WTI prices, it is expected that differentials will widen, but this effect was exacerbated in the fourth quarter because of stagnation in the heavy refined product market and an increase in the supply of heavy sour crude from OPEC. As a result of this widening differential, our realized price on medium and heavier grade crude oil was constricted. Through 2004, this impact was mitigated by 4,250 BOE/d of hedges on the heavy crude differential. We currently have no differential hedges beyond 2004. We will continue to monitor the market with a view to reducing the impact of changing differentials on realized prices. The market for heavy oil price financial derivatives is not well established and we may need to enter into other forms of transactions to achieve this objective. Our acquisitions in 2004 have helped reduce our exposure to heavy oil differentials by diversifying our commodity mix.

In addition to hedging, we also strive to maximize the price received for our heavy oil production by marketing into streams that offer better pricing, using our natural gas liquids production as a hedge against the cost of condensate and utilizing heated pipelines to reduce blending requirements. If the price of WTI remains high in 2005, we expect differentials to remain wide versus historical levels, but narrow from those experienced in the fourth quarter of 2004.

In 2004, the Canadian dollar continued its strengthening trend, which began in 2002. This dampened the revenue gains from the rising WTI price for Canadian oil producers. The Canadian dollar reached a twelve year high on November 26, 2004 of $0.8493. This compares to the year end 2003 level of $0.7738 and the December 31, 2004 level of $0.8308. As a result of our U.S. dollar denominated senior notes, which were issued in October 2004, we have a partial natural hedge against currency exchange rates. In addition to this natural hedge, we have hedged U.S.$8.3 million per month through 2005, with a floor at U.S.$0.8333. The long term outlook for the Canadian dollar remains robust, as Canada continues to experience strong demand for its commodities.

After completing the acquisition of properties in East Central and Southern Alberta in September of 2004, our natural gas weighting increased from approximately 2% to approximately 13% of total production. As a result, the impact of natural gas prices has become more significant to us. Natural gas demand growth remains strong, particularly for electricity generation. Recently the price has become more closely related to oil pricing as the effects of fuel switching to high sulphur fuel oil now set a floor, rather than a ceiling, on the price of natural gas. During 2004, the price of natural gas at AECO experienced volatility due primarily to storage and weather related issues, and reached a peak of $8.19/GJ on October 27th and a low of $4.60/GJ on November 19th. It is expected that natural gas prices will remain healthy in 2005 with the potential for considerable price spikes should WTI prices remain strong and primary markets experience either a warm summer or a cold winter season. We have not, as yet, hedged any of our natural gas price exposure.

We anticipate that our gas production as a percentage of total production may decline slightly in 2005 as the 2005 capital budget does not include a proportionate amount for natural gas property development.

Royalties

We pay Crown, freehold or overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices. In certain situations, such as with some heavy oil production, the Alberta Energy and Utilities Board grants royalty 'holidays', effectively eliminating royalties on a specific well or group of wells.

For the three months ended December 31, 2004, our net royalties as a percentage of revenue were 16.5% ($21.2 million), compared to 16.0% ($6.4 million) in the same period in 2003, despite stronger commodity prices. The small increase in the royalty rate in the fourth quarter 2004 compared with the same period in 2003, relative to the 30% increase in net prices, is attributable to the lower royalty rate of the properties acquired in September.

For the full year 2004, our net royalties as a percentage of revenue were 16.4% ($54.2 million), compared to 13.8% ($16.4 million) in 2003. The higher royalty rate for full year 2004 compared to 2003 is primarily due to the higher royalty rates on the North Central Alberta properties and the Southeast Saskatchewan properties, which were acquired in the second quarter of 2004 and the fourth quarter of 2003, respectively. For 2005, we are anticipating our royalty rate as a percentage of net revenues to be between 15 and 17%.

Operating Expense

($/BOE)	Three Months Ended December 31 2004	2003	% Change	Year Ended December 31 2004	2003	% Change
Operating expense	**$ 7.55**	$ 9.76	(23%)	**$ 8.72**	$ 9.33	(7%)
Realized gains on electricity derivative contracts	**(0.18)**	(0.26)	(31%)	**(0.24)**	(0.39)	(38%)
Net operating expense	**$ 7.37**	$ 9.50	(22%)	**$ 8.48**	$ 8.94	(5%)

Our operating expenses (before the impact of realized gains on electricity derivative contracts) for the three and twelve month periods ending December 31, 2004 were $25.7 million ($7.55/BOE) and $73.4 million ($8.72/BOE), respectively. For the same respective periods in 2003 (before the impact of realized gains on electricity derivative contracts), operating expenses were $13.3 million ($9.76/BOE) and $37.6 million ($9.33/BOE). The decrease in 2004 compared to 2003 is primarily due to the acquisition of lower operating cost properties from Storm and EnCana, slightly offset by the acquisition of the higher operating cost properties in Southeast Saskatchewan in the fourth quarter of 2003. The 2004 operating cost figures are in line with our previous guidance issued in mid-2004.

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.

Electricity costs represent a significant portion of our operating costs, so efforts are constantly focused on ways to reduce electricity costs. In 2004, approximately 37% of our operating expenses related to electricity consumption, compared to approximately 60% in 2003. This reduction is a result of two factors. We handle significant volumes of water on our East Central Alberta oil production and processing and disposing of the water requires a large amount of electricity. In 2004, as part of our ongoing initiatives to control costs, we found a more efficient method to dispose of produced water, by injecting it into a different reservoir at vacuum, and reduced power costs in this core area. In addition, a large portion of the new properties acquired in 2004 do not require as much electricity in relation to other operating costs.

During 2004, monthly electricity costs varied from $42.46 per megawatt hour (MWh) to $67.13/MWh. Through the application of electricity hedges, our exposure to volatile and rising costs was tempered. Alberta is a deregulated market and electricity prices are expected to remain volatile through 2005 and into 2006. We continue to mitigate this risk through hedging and are working on a variety of site optimization opportunities to minimize power consumption. We anticipate realizing further benefits from our electricity hedges in 2005 and 2006. Approximately 85% and 70% of our estimated Alberta electricity usage for 2005 and 2006 are hedged at an average price of $47.50/MWh. This hedging activity should keep our 2005 electricity costs close to levels experienced in 2004, with operating costs in 2005 expected to average between $7.75/BOE and $8.50/BOE.

Benchmark Price	Three Months Ended December 31 2004	2003	% Change	Year Ended December 31 2004	2003	% Change
Alberta Power Pool electricity price ($/MWh)	**$ 54.94**	$ 54.77	0.3%	**$ 54.59**	$ 62.99	(13%)

General and Administrative (G&A) Expense

($ millions, except per BOE)	Three Months Ended December 31 2004	2003	% Change	Year Ended December 31 2004	2003	% Change
G&A	**$ 3.3**	$ 2.1	57%	**$ 8.6**	$ 4.1	110%
Per BOE ($/BOE)	**0.98**	1.50	(35%)	**1.02**	1.02	0%
Unit right compensation expense	**10.6**	0.1	10,500%	**11.4**	0.2	5,600%
Per BOE ($/BOE)	**3.11**	0.15	1,973%	**1.35**	0.06	2,150%
Total G&A	**$ 13.9**	$ 2.2	532%	**$ 20.0**	$ 4.3	365%
Per BOE ($/BOE)	**4.09**	1.65	148%	**2.37**	1.08	119%

The majority of our G&A expenses are related to salaries and other staffing costs. The portion of G&A charged against income in the fourth quarter of 2004 totaled $13.9 million ($4.09/BOE) compared to $2.2 million ($1.65/BOE) for the fourth quarter of 2003. For the twelve month period ended December 31, 2004, G&A expense totaled $20.0 million ($2.37/BOE) compared to $4.3 million ($1.08/BOE) for the same period in 2003.

The increase in G&A on a per BOE basis of 148% in the fourth quarter of 2004 compared to the same period in 2003 is the result of unit right compensation expense and annual bonuses paid and accrued for 2004.

A modification to our Unit Incentive Rights Plan in the fourth quarter of 2004 resulted in a prospective change in accounting for unit appreciation rights (UARs). In previous quarters, UARs were valued at the date they were granted using a mathematical option valuation model and an expense was charged to G&A based on that valuation. Following the prospective accounting change, we now value vested UARs at the difference between exercise price and market price at each reporting period end to determine the related liability at the end of the period. Changes in the assumptions used in determining this liability, such as our Trust Unit price, the exercise price and the number of UARs vested at each accounting period will cause this liability to fluctuate and the difference is reflected as expense on the consolidated statement of income. For the fourth quarter of 2004, this non-cash amount in G&A accounted for $2.57/BOE.

In addition, approximately $1.8 million of UARs exercised and settled for cash in the fourth quarter were charged to income. Annual bonuses paid and accrued impacted the fourth quarter by approximately $0.28 per BOE. In 2005, we expect cash G&A expenses to average between $0.90-$1.00 on a per BOE basis.

Interest Expense	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2004**	2003	% Change	**2004**	2003	% Change
Interest on short term debt	**$ 3.7**	$ 2.2	68%	**$ 9.4**	$ 5.6	68%
Interest on long term debt	**5.5**	–	–	**5.5**	–	–
Total interest expense	**$ 9.2**	$ 2.2	318%	**$ 14.9**	$ 5.6	166%

Interest expense in the three and twelve month periods ended December 31, 2004 was higher than in the same periods in 2003, primarily due to higher average debt balances resulting from the property acquisitions completed in the last half of 2004. Interest expense will be higher in 2005 than in the full year 2004 for this same reason. In addition, due to changes in generally accepted accounting principles, our convertible debentures will be reflected as debt, rather than equity, in 2005. This will result in interest on our convertible debentures being reflected in interest on long-term debt and reflected in net income.

Interest expense reflects the interest accrued on our outstanding bank debt 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 flow ratio. Our outstanding convertible debentures have fixed interest rates at 9% for the first series (issued in January 2004) and 8% for the second series (issued in August 2004). The large number of conversions of convertible debentures during 2004 has reduced the balance of both series, and will result in lower interest expense on these debentures in 2005 than 2004. We issued long-term U.S. dollar denominated senior notes in October 2004, which bear interest at 7 7/8% and mature on October 15, 2011. Issuing the senior notes enabled us to repay our bank bridge loan and a significant portion of the senior credit facility balance incurred with the acquisition of properties in September. Undertaking the long term senior note issue provides us with a natural hedge against fluctuations in currency exchange rates, increased financial flexibility and access to the U.S. capital markets.

Depletion, Depreciation and Accretion Expense

	Three Months Ended December 31			Year Ended December 31		
($ millions, except per BOE)	**2004**	2003	% Change	**2004**	2003	% Change
Depletion and depreciation	**$ 44.7**	$ 9.2	386%	**$ 88.8**	$ 29.4	202%
Depletion of capitalized asset retirement costs	**3.8**	1.6	138%	**9.8**	4.5	118%
Accretion on asset retirement obligation	**1.3**	0.7	86%	**4.2**	1.8	133%
Total depletion, depreciation and accretion	**$ 49.8**	$ 11.5	333%	**$ 102.8**	$ 35.7	188%
Per BOE ($/BOE)	**14.62**	8.41	74%	**12.20**	8.86	38%

In the fourth quarter of 2004, our overall depletion, depreciation and accretion (DD&A) rate per BOE is higher compared to the same period in 2003, primarily due to the acquisitions made in 2004. The higher DD&A rate reflects the higher value netback for the acquired properties.

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 and any U.S. dollar deposits and cash balances. For the year ended December 31, 2004, a foreign exchange gain of $7.1 million compares to a foreign exchange gain of $4.4 million in 2003. The higher gain in 2004 was primarily driven by the strengthening of the Canadian dollar to the U.S. dollar during the period the senior notes were outstanding.

Derivative 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 derivative instruments (including swaps, options and collars) to manage commodity price, 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 electricity price and heat rate based derivatives 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.

When there is a high degree of correlation between the price movements in a derivative financial instrument and the item designated as being 'hedged' and management documents the effectiveness of this relationship, we may employ hedge accounting. Effective January 1, 2004, we implemented CICA Accounting Guideline 13, *"Hedging Relationships"* (AcG-13), which addresses the identification, designation and effectiveness of financial contracts for the purpose of applying hedge accounting. Under this guideline, financial derivative contracts must be designated to the underlying revenue or expense stream that they are intended to hedge, and then tested to ensure they remain sufficiently effective in order to continue hedge accounting. As of October 1, 2004, we ceased to apply hedge accounting to our derivative contracts. As a result, from October 1, 2004 all of our derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period. The mark-to-market valuation represents the amount that would be required to settle the contract on the period end date. Collectively our contracts had a mark-to-market unrealized non-cash loss position on the balance sheet of $15.4 million as at December 31, 2004. Please refer to Note 16 in the consolidated financial statements for further information.

For 2004, we recorded a realized loss on commodity derivative contracts of $52.4 million, and an unrealized loss of $11.3 million. The realized loss portion reflects the revenue lost due to the derivative contracts in effect during that period. In 2003, we recorded a hedging loss of $18.9 million. Derivative contract losses in 2005, assuming similar commodity price levels, will be smaller than those experienced in 2004 as the volume of production hedged with swaps and collars with price ceilings has diminished.

Deferred Charges and Deferred Gains

The deferred charges asset balance on the balance sheet is comprised of two main components: deferred financing charges and deferred assets related to the discontinuation of hedge accounting. The deferred financing charges relate primarily to the issuance of the senior notes and bank debt and are amortized over the life of the debt. On the initial adoption of AcG-13, we recorded a deferred charge of $5.5 million, relating to the contracts not qualifying for hedge accounting at the time of adoption.

We discontinued the use of hedge accounting for all of our derivative financial instruments effective October 1, 2004. For contracts where hedge accounting had previously been applied, a deferred charge of $20.2 million and a deferred gain of $2.5 million 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 derivative contracts asset or liability. The deferred amount is recognized in income in the period in which the underlying transaction is recognized.

For the year ended December 31, 2004, $14.9 million of the deferred charge and $350,000 of the deferred gain has been amortized and recorded in gains and losses on derivative contracts. At December 31, 2004, $10.8 million has been recorded as a deferred charge, with $2.2 million recorded as a deferred gain related to derivative contracts.

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 Storm Energy Ltd., 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 will be assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount.

Future Income Taxes

Future income taxes reflect 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 the related income tax balances. 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. While we realized a recovery of future income taxes during the year, the overall future tax liability on the balance sheet increased due to the future income taxes booked on the acquisition of Storm Energy Ltd. (described previously under “Goodwill”).

We recorded future income tax expense of $3.6 million for the three month period ended December 31, 2004, and a recovery of $4.9 million for the three months ended December 31, 2003. Future income tax recoveries for the twelve month periods ended December 31, 2004 and 2003 were $10.4 million and $9.0 million, respectively.

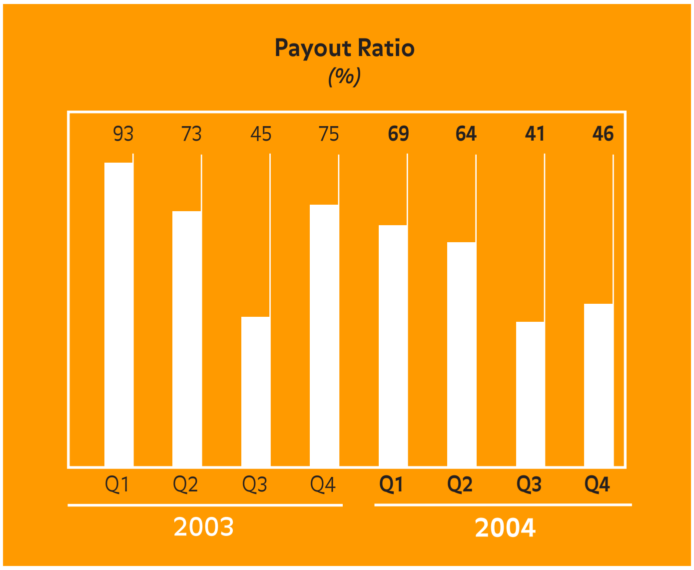
Asset Retirement Obligations (ARO)

Effective January 1, 2004, we adopted CICA Handbook Section 3110 “*Accounting for Asset Retirement Obligations*”. In connection with a property acquisition or development expenditure, we will 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 that underlie the obligation.

Our asset retirement obligation has increased by $48.1 million in 2004 mainly due to the acquisitions of the North Central, East Central and Southern Alberta assets during the year.

Liquidity and Capital Resources

Our drilling and operational enhancement programs, as well as current financial commitments, are expected to be financed from cash flow from operations (see "Certain Financial Reporting Measures" in this MD&A). Our cash distributions to Unitholders are financed solely from cash flow from operations. In 2004, our distribution payout ratio of 50% (calculated by dividing distributions to Unitholders into cash flow from operations) resulted in significant free cash flow available for our capital expenditure programs and debt repayment. Management anticipates sufficient cash flow from operations in 2005 to be available for the planned capital development program of $75 million, expected distributions of $0.20 per Unit per month and to repay a portion of outstanding bank debt. Given our significant amount of oil price hedges in place, management believes cash flows in 2005 will exceed cash distributions and budgeted capital expenditures under most WTI price scenarios.



Should commodity prices stay strong, heavy oil differentials narrow and the Canadian dollar stabilize, we should have sufficient cash flow to repay a significant portion of our outstanding bank debt by the end of 2005. It is also important to note that to the extent our Unitholders elect to receive distributions in the form of Trust Units rather than cash under our Distribution Reinvestment plan (DRIP), this further reduces net cash outlays. During 2004, DRIP participation was approximately 21%.

The table below provides an analysis of our debt structure, including some key debt ratios. We believe that the current capital structure is appropriate given our low payout ratio and the significant hedges in place. We intend to use cash flow after distributions and capital expenditures to repay bank debt.

	Year Ended December 31		
($ millions)	**2004**	2003	% Change
Bank debt	**$ 75.5**	$ 63.3	19%
Senior notes	**300.5**	–	–
Working capital deficit (surplus) excluding bank debt (2)	**27.8**	(9.8)	(384%)
Equity bridge notes	**–**	25.0	–
Convertible debentures	**25.9**	–	–
Net debt obligations	**$ 429.7**	$ 78.5	447%
Fourth quarter cash flow annualized (1)	**$ 214.2**	$ 54.8	291%
Trailing net debt to cash flow (times)	**2.0**	1.4	43%

(1) Reflects realized hedging losses which were significant in the fourth quarter given the nature of our oil price hedges, which were primarily collars and swaps. Our hedges in 2005 are primarily instruments which do not place a cap on WTI price realizations.

(2) Excludes current portion of derivative contracts assets and liabilities and Trust Unit incentive plan liability.

From time to time we may require additional external financing, in the form of either debt or equity, to further our business plan of maintaining production and reserves through acquisitions and capital expenditures. Our 2005 capital expenditure budget is likely not sufficient to maintain current production levels, but our cash flow from operations is expected to be at least sufficient to pay our distributions to Unitholders and fund our capital spending program. We strive to maintain financial flexibility that will enable us to capitalize on acquisition opportunities as they arise or increase our capital spending budget. In financing any new acquisitions, we will likely access both the debt and equity markets in appropriate amounts so as to maintain a supportable capital structure. We target debt to cash flow between 1.0 to 1.5 times, but are comfortable with slightly higher levels immediately following an acquisition provided adequate hedging is in place to support forecasted cash flows. Our ability to obtain financing is subject to external factors including, but not limited to, fluctuations in equity and commodity markets, economic downturns, and interest and foreign exchange rates. Adverse changes in these factors could require our management to alter our current business plan.

As a result of the acquisition of assets in East Central and Southern Alberta in September, our bank credit facility increased to $325 million. Proceeds from the issuance of the U.S.$250 million senior notes were used to partially repay amounts drawn under the credit facility. Outstanding bank debt plus working capital deficiency at December 31, 2004 totaled $103.3 million, leaving approximately $222 million undrawn. The amount available under the bank credit facility may be redetermined by our lenders from time to time based on lenders' estimates of future cash flows from our oil and natural gas properties. Thus, our ability to draw on this facility may change. We may draw under this facility, or complete additional financings in the form of senior notes, convertible debentures or Trust Units to expand the capital program or to finance additional acquisitions. We may also utilize bridge financing, similar to that used in 2003 and 2004, if required.

Our bank debt will be repaid or refinanced in June 2005 with a similar facility. As lenders calculate the amount of such facilities using conservative price assumptions, management does not anticipate a significant change to the amount available under the new facility. The long term to maturity of the senior notes allows us significant flexibility in determining how that particular debt is refinanced.

A breakdown of our outstanding Trust Units and potentially dilutive instruments are as follows:

	As at December 31		
($ amounts are in 000s)	**2004**	2003	% Change
Trust Units outstanding	**41,788,500**	17,109,006	144%
Exchangeable shares outstanding	**455,547**	–	–
Trust Units represented by exchangeable shares (1)	**485,003**	–	–
Market price of Trust Units at end of period ($/unit)	**22.95**	14.07	63%
Total market value of Trust Units at end of period (2)	**$ 970,177**	$ 240,724	303%
9% convertible debentures (3)	**$ 10,700**	$ –	–
8% convertible debentures (4)	**$ 15,159**	$ –	–
Trust Unit rights outstanding (5)	**1,117,725**	1,065,150	5%
Total Trust Units, diluted (6)	**45,088,376**	18,174,156	148%

(1) Exchangeable shares are exchangeable into Trust Units at the election of the holder at any time. Based on the exchange ratio in effect on December 31, 2004 of 1.06466.

(2) Including Trust Units outstanding and assuming exchange of all exchangeable shares.

(3) Each debenture in this series has a face value of $1,000 and is convertible, at the option of the holder at any time, into Trust Units at a price of $14.00 per Trust Unit. If Debenture holders converted all outstanding debentures in this series at December 31, 2004 an additional 764,286 Trust Units would be issuable.

(4) Each debenture in this series has a face value of $1,000 and is convertible, at the option of the holder at any time, into Trust Units at a price of $16.25 per Trust Unit. If Debenture holders converted all outstanding debentures in this series at December 31, 2004 an additional 932,862 Trust Units would be issuable.

(5) Exercisable at an average price of $10.09 per Trust Unit as at December 31, 2004.

(6) Fully diluted units differ from diluted units for accounting purposes. Fully diluted includes Trust Units outstanding as at December 31 plus the impact of the conversion of exercise of exchangeable shares, Trust Unit rights and convertible debentures if completed at December 31.

	As at December 31		
($ millions)	**2004**	2003	% Change
Total market capitalization(1)	**$ 970.2**	$ 240.7	303%
Net debt	**429.7**	78.5	447%
Enterprise value (total capitalization)(2)	**$ 1,399.9**	$ 319.2	339%
Net debt as a percentage of enterprise value (%)	**31%**	25%	24%

(1) Reflects conversion of exchangeable shares into Trust Units.

(2) Enterprise value as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds we have received from equity and debt.

The increase in net debt as at December 31, 2004 compared to 2003 is primarily the result of the Storm and EnCana acquisitions. Of the convertible debentures outstanding at December 31, 2004, $6.6 million have converted into Units through March 24, 2005 and we anticipate continued conversions through 2005.

Contractual Obligations

We have entered into the following contractual obligations:

Annual Contractual Obligation *($000s)*	Total	Maturity Less Than 1 year	Years 1-3	Years 4-5	After 5 Years
Short and long-term debt	376,019	75,519	–	–	300,500
Interest on short and long-term debt	163,024	25,997	70,993	47,329	18,705
Interest on convertible debentures	10,008	2,176	6,527	1,305	–
Operating and premise leases	7,094	400	4,304	2,390	–
Transportation and storage commitments	99	35	39	25	–
Capital commitments	700	700	–	–	–
Asset retirement obligations	334,803	–	729	3,648	330,426
Total	891,747	104,827	82,592	54,697	649,631

As at December 31, 2004, Harvest had entered into physical and financial contracts for production with average deliveries of approximately 23,524 barrels per day in 2005 and 12,500 barrels per day in 2006. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices and the U.S./Canadian dollar exchange rate. Please see Note 16 to the consolidated financial statements for further details.

Off Balance Sheet Arrangements

We have a number of immaterial operating leases in place on moveable field equipment, vehicles and office space. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Related Party Transactions

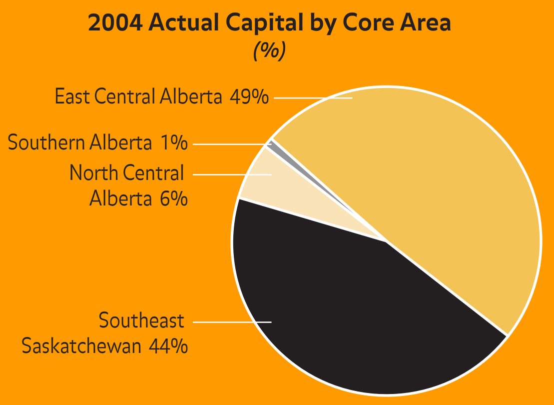
One of our directors and a corporation controlled by that director had advanced $25 million to Harvest pursuant to the equity bridge notes as at December 31, 2003. On January 2, 2004 we paid $665,068 in accrued interest on these notes. On January 26 and 29, 2004 we repaid the principal amount and paid $185,232 of interest accrued since December 31, 2003. The notes were amended on June 29, July 7 and July 9, 2004. These notes were then re-drawn by $30 million 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 Harvest and were subordinate to the interest of the senior secured lenders pursuant to Harvest Operations' credit facility.

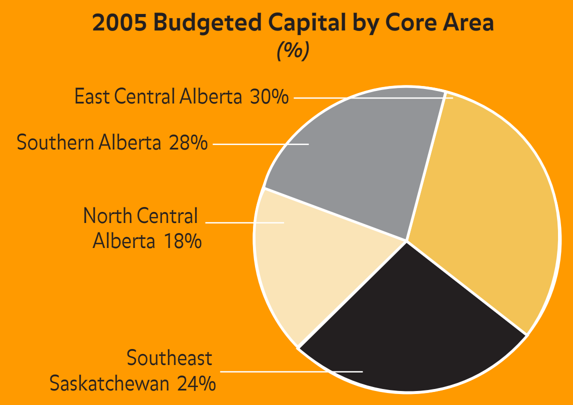
We had the option to settle the quarterly interest payments under the equity bridge notes with cash or the issue of Trust Units. If we elected to issue Trust Units, the number of Trust Units to be issued to settle a quarterly interest payment would be the equivalent to the quarterly payment amount divided by 90% of the most recent ten-day weighted average trading price. We had the option at maturity of the notes to settle the principal obligation with cash or with the issue of Trust Units. The terms to settle principal with units is the same as with the interest option described above.

A corporation controlled by one of our directors sublets office space from us and we provide administrative services to that corporation on a cost recovery basis.

Capital Asset Expenditures

($ millions)	Year Ended December 31 **2004**	2003	% Change
Land and undeveloped lease rentals	**$ 0.8**	$ 0.1	700%
Geological and geophysical	**0.5**	0.2	150%
Drilling and completion	**23.0**	10.1	128%
Well equipment, pipelines and facilities	**14.0**	15.1	(7%)
Capitalized G&A expenses	**3.6**	1.3	177%
Furniture, leaseholds and office equipment	**0.8**	0.4	100%
Total capital asset additions	**$ 42.7**	$ 27.2	57%
Acquisitions	**$ 706.0**	$ 108.7	549%
Total capital asset expenditures	**$ 748.7**	$ 135.9	451%





Development expenditures excluding acquisitions totaled $8.8 million for the three month period ended December 31, 2004, resulting in full year development capital expenditures of $42.7 million. This compares to $27.2 million for the full year 2003. Throughout 2004, our capital expenditures were dedicated to ongoing optimization and development of existing assets, primarily in our existing core areas. We drilled a total of 30.5 net wells in 2004, with a success rate of 100%.

Excluding acquisitions, we expect that 2005 development capital expenditures will total approximately $75 million, and will be focused on production and reserve additions, and operating efficiency programs. In 2005, the development capital will be directed to the new areas including North Central Alberta and Southern Alberta, with an ongoing focus applied to East Central Alberta and Southeast Saskatchewan. As the development program progresses, we may reallocate funds between areas based on results achieved, with the goal of achieving optimal returns on capital investment. We do not anticipate being able to maintain production at year end 2004 rates through 2005 with our planned 2005 capital program. We anticipate average production for the year to be between 34,000 and 36,000 BOE/d.

Distributions to Unitholders and Taxability

Distributions to Unitholders are financed with cash flow from operations. Since inception, we have communicated our intention to pursue a strategy that will allow us to sustain $0.20 per Unit per month in distributions. During 2004, we paid $0.20 per Trust Unit for each month ($59.6 million) to Unitholders. This is the same per Unit level paid to Unitholders through 2003 ($29.1 million). The higher level of absolute distributions paid reflects a greater number of Units outstanding following the August equity issue, as well as the ongoing conversion of both the 9% and 8% series of convertible debentures. However, our payout ratio has declined over the past two years, resulting in a 46% payout ratio in the fourth quarter of 2004, compared to 75% in the same period in 2003. Retained cash flow will continue to be used to fund debt repayment, capital development investments and possible future acquisition opportunities.

	Three Months Ended December 31			Year Ended December 31		
($ millions, except per Trust Unit amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Cash distributions declared	**$ 24.8**	$ 10.2	143%	**$ 64.6**	$ 30.7	110%
Per Trust Unit	**0.60**	0.60	0%	**2.40**	2.40	0%
Taxability of distributions (%)	**n/a**	n/a	–	**100%**	41%	144%
Payout ratio (%)	**46%**	75%	(39%)	**50%**	66%	(25%)

Of the total distribution amount paid in 2004, $12.6 million was reinvested by Unitholders through the issue of 0.8 million Trust Units under the Distribution Reinvestment Plan ("DRIP"). This reflects 21% participation under the DRIP. During 2005, management believes the DRIP will remain at levels similar to 2004. Should the percentage decrease, we will need to use a larger amount of cash flows to pay monthly distributions.

Our distributions paid to Unitholders in 2004 totaled $0.20 per Trust Unit per month for an annual total of $2.40 per Trust Unit. However, we earned more taxable income in 2004 than the amounts distributed to Unitholders.

As a result, all distributions paid in the year are 100% taxable. No amount of the distributions is a return of capital. Our trust indenture requires that any taxable income we earned in Harvest Energy Trust as an independent taxable entity that exceeds the amount paid in distributions automatically becomes payable to Unitholders. As a result of the excess taxable income earned in 2004, our Unitholders will receive an additional allocation of taxable income of $0.252 per unit, which is also 100% taxable. This amount will be reported as a corresponding increase in taxable income shown on those Unitholders' T3 slips.

In settlement of this additional taxable income payable, Unitholders of record on March 31, 2005 will receive an additional payment of Trust Units equal to $0.252 per Unit. Trust Units will be valued as at December 31, 2004 for this purpose, in accordance with the trust indenture. Applying the closing price of the Trust Units on December 31, 2004 of $22.95, each Unitholder of record on March 31, 2005 will receive 0.01098 of a Trust Unit per Trust Unit held on that date in settlement of this incremental amount of taxable income. This payment, representing the excess income, will be made concurrently with the distribution payment to Unitholders on April 15, 2005.

Payments to U.S. Unitholders are subject to 15% Canadian withholding tax, which applies to the taxable portion of the distribution. After consulting with our U.S. tax advisors, we are of the view that 2004 distributions are "qualified dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003. These dividends are eligible for the reduced tax rate applicable to long-term capital gains. However, the distributions may not be qualified dividends in certain circumstances, depending on the holder's personal situation (i.e. if an individual holder does not meet a holding period test). Where the distributions do not qualify, they should be reported as ordinary dividends. U.S. and other non-resident Unitholders are urged to consult independent legal advice on how their distributions should be treated for tax purposes.

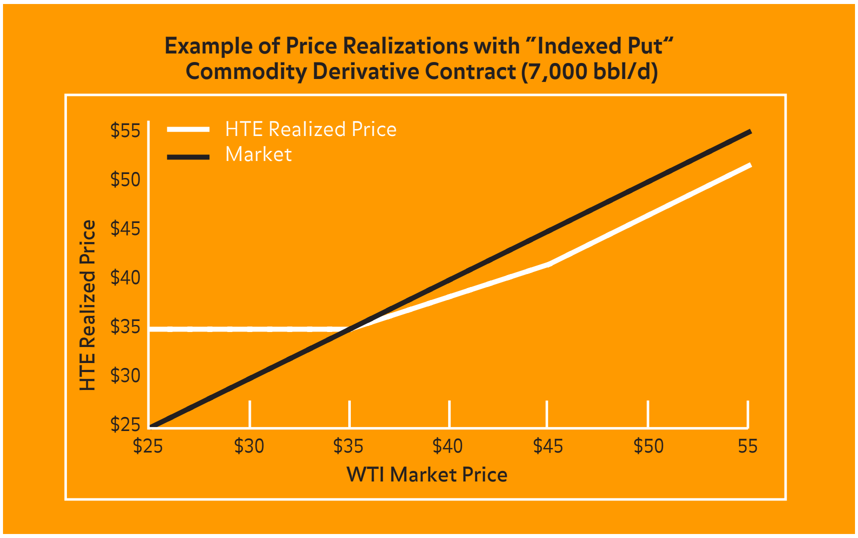
Sensitivities

The table below indicates the impact of changes in key variables on several of our financial measures. The figures in this table are based on the Units outstanding as at December 31, 2004 and our existing commodity price risk management program, and are provided for directional information only.

	Variable				
	WTI Price/bbl	Heavy Oil Price Differential/bbl	Crude Oil Production	Canadian Bank Prime Rate	Foreign Exchange Rate U.S./Cdn.
Assumption	$ 40.00 U.S.	$15.00 U.S.	35,000 bbl/d	4.25%	1.21
Change (plus or minus)	$ 1.00 U.S.	$ 1.00 U.S.	1,000 bbl/d	1.00%	0.01
Annualized impact on:					
Cash flow from operations ($000s)	$ 4,630	$ 7,456	$ 12,370	$ 631	$ 2,399
Per Trust Unit, basic	$ 0.12	$ 0.18	$ 0.29	$ 0.02	$ 0.06
Per Trust Unit, diluted	$ 0.11	$ 0.17	$ 0.29	$ 0.02	$ 0.05
Payout ratio	1.4%	2.2%	3.7%	0.2%	0.7%

As noted above, our commodity price risk management program can reduce sensitivities due to the oil price derivatives executed under our risk management program. Those contracts in place as at December 31, 2004 are documented in the table below. The prices shown for collars, indexed puts and participating swaps are floor prices. The nature of those instruments allows us to participate in positive price movements above these levels, while providing fixed price realizations if the market price drops below the floor price.

	2005		2006	
	Volume (bbl/d)	Floor Pricing ($/bbl)	Volume (bbl/d)	Floor Pricing ($/bbl)
WTI Crude Oil Swaps	1,028	$ 23.12	–	–
WTI Crude Oil Collars	3,996	$ 28.16	–	–
WTI Indexed Put Contracts	18,500	$ 35.95	3,750	$ 34.00
WTI Participating Swaps	–	–	8,750	$ 38.16



The graph to the left shows the Harvest realized price plotted against a changing WTI price. The white line is our realized price and the black line is the WTI price. The floor is set at $35, so if WTI is below $35, we realize $35. For spot prices above $35, we receive spot price less 34% of the difference between spot price and $35, until WTI reaches $45, at which time we will realize the WTI price less $3.40 at that price point and higher.

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 calculation 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 the drilling activity we undertake is of a low risk nature and success rates are high; however, each policy is likely to generate a different carrying value of capital assets and a 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 on. 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 $11 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 cash flow 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 to a range between high U.S.$20 to low U.S.$30 levels, 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.

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.

Changes in Accounting Policy

Asset Retirement Obligations

In December 2002, the CICA issued Handbook Section 3110, *"Asset Retirement Obligations"*. This standard requires recognition of a liability representing the fair value of the future retirement obligations associated with capital assets. This fair value is capitalized and amortized over the same period as the underlying asset.
The standard is effective for all fiscal years beginning on or after January 1, 2004. See Notes 3 and 7 to our consolidated financial statements.

Hedging Relationships

In November 2002, the CICA published an amended Accounting Guideline 13, *"Hedging Relationships"*. The guideline establishes conditions where hedge accounting may be applied. It is effective for years beginning on or after July 1, 2003. The guideline impacted our net income and net income per Trust Unit, as certain financial instruments for oil and natural gas do not qualify for hedge accounting. See Note 16 to our consolidated financial statements. Where hedge accounting does not apply, any changes in the fair values of the financial instruments relating to a period can either reduce or increase net income for that period. We adopted this standard January 1, 2004, which has resulted in a reduction in our pretax income of $11.3 million. At October 1, 2004, we ceased hedge accounting for all of our derivative instruments.

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; 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 held for trading or they are derivatives. 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 "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, foreign currency, and unrealized gains or 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. 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.

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 do not expect this guideline to have a material impact on our consolidated financial statements.

Financial Instruments

The CICA Handbook Section 3860 *"Financial Instruments – Disclosure and Presentation"* has been amended to provide guidance for classifying certain financial instruments that embody obligations that may be settled by the issuance of the issuer's equity shares as debt when the instrument that embodies the obligations does not establish an ownership relationship. As a result of this amendment, the convertible debentures will be reclassified from equity to debt, with possibly a small portion representing the value of the conversion feature remaining in equity. At this time, management has not fully assessed the allocation, if any, between debt and equity. The mandatory effective date for the amendment is for fiscal years beginning on or after November 1, 2004.

Operational and Other Business Risks

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: operational risk, reserve risk, commodity price risk, financial risk, 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 Corp., and are intended to mitigate the risks noted above as follows:

Operational risk associated with the production of oil and natural gas:
- 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.

Reserve risk with respect to 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 risk, arising from fluctuations in oil and natural gas prices due to market forces:
- 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 Corp. action to be taken;
- Maintaining a program to manage variability in commodity prices and electricity costs utilizing swaps, collars and option contracts with a portfolio of credit-worthy counterparties; and
- Maintaining a low cost structure to maximize product netbacks.

Financial risk, such as volatility in equity markets, foreign exchange rates, interest rates, price differentials, credit risk and ability to meet debt service obligations:
- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining up to 50% of the cash available for distribution to finance capital expenditures and future property acquisitions;
- Monitoring our financial position and foreign exchange markets with the intent of taking steps necessary to minimize the impact of fluctuations in foreign currency exchange rates;
- Comparing actual financial performance against pre-determined expectations and making changes where necessary; and
- Carrying adequate insurance to cover property and business interruption losses.

Environmental, health and safety risk associated with well and production facilities:
- Adhering to our safety program and keeping abreast of current industry practices;
- Committing funds on an ongoing basis, toward the remediation of potential environmental issues; and
- Accumulating sufficient cash resources to pay for future asset retirement costs.

Regulatory risk arising from changing government policy risks, 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.

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 Audit Committee of Harvest's Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

"Signed"

Jacob Roorda
President

"Signed"

David Rain
Vice President and Chief Financial Officer

March 24, 2005

Auditors' Report

To the Unitholders of Harvest Energy Trust

We have audited the consolidated balance sheets of Harvest Energy Trust as at December 31, 2004 and 2003 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, 2004 and 2003 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"

Chartered Accountants
Calgary, Canada

March 24, 2005

Consolidated Balance Sheets

As at December 31, *(thousands of Canadian dollars)*	2004	2003 *(Restated, Note 3)*
Assets		
Current assets		
Accounts receivable	**$ 44,028**	$ 19,168
Current portion of derivative contracts [Note 16]	**8,861**	–
Prepaid expenses and deposits	**3,014**	12,131
	55,903	31,299
Deferred charges [Note 16]	**24,507**	1,989
Long term portion of derivative contracts [Note 16]	**3,710**	–
Capital assets [Notes 4 and 5]	**918,397**	210,543
Future income tax [Note 15]	**–**	12,609
Goodwill [Note 4]	**43,832**	–
	$ 1,046,349	$ 256,440
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities [Note 6]	**$ 76,251**	$ 18,083
Cash distribution payable	**8,358**	3,422
Current portion of derivative contracts [Note 16]	**27,927**	–
Bank debt [Note 8]	**75,519**	63,349
	188,055	84,854
Deferred gains [Note 16]	**2,177**	–
Senior notes [Note 9]	**300,500**	–
Asset retirement obligation [Notes 3 and 7]	**90,085**	42,009
Future income tax [Note 15]	**34,671**	–
	615,488	126,863
Unitholders' equity		
Unitholders' capital [Note 11]	**465,131**	117,407
Exchangeable shares [Note 13]	**6,728**	–
Equity bridge notes [Notes 10 and 17]	**–**	25,000
Convertible debentures [Note 14]	**24,696**	–
Accumulated income	**31,416**	19,478
Contributed surplus	**–**	239
Accumulated cash distributions	**(97,110)**	(32,547)
	430,861	129,577
	$ 1,046,349	$ 256,440

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

Approved by the Board of Directors:

"Signed"

John A. Brussa
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)*	**2004**	2003 *(Restated, Note 3)*
Revenue		
Oil and natural gas sales	**$ 331,331**	$ 119,351
Royalty expense, net	**(54,236)**	(16,412)
	277,095	102,939
Expenses		
Operating	**73,442**	36,045
General and administrative	**8,621**	4,101
Unit right compensation expense	**11,359**	239
Interest on short term debt	**9,445**	5,582
Interest on long term debt	**5,488**	–
Depletion, depreciation and accretion	**102,776**	35,727
Foreign exchange gain	**(7,111)**	(4,374)
Gains and losses on derivative contracts	**63,701**	18,924
	267,721	96,244
Income before taxes	**9,374**	6,695
Taxes		
Large corporations tax	**1,505**	157
Future income tax recovery [Note 15]	**(10,362)**	(8,978)
Net income for the year	**$ 18,231**	$ 15,516
Interest on equity bridge notes [Notes 10 and 17]	**(1,070)**	(870)
Interest on convertible debentures [Note 14]	**(5,223)**	–
Accumulated income, beginning of year	**19,478**	5,136
Retroactive application of change in accounting policy [Note 3]	**–**	(304)
Accumulated income, end of year	**$ 31,416**	$ 19,478
Net income per Trust Unit, basic [Note 11]	**$ 0.47**	$ 1.16
Net income per Trust Unit, diluted [Note 11]	**$ 0.45**	$ 1.13

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flows

For the Years Ended December 31, *(thousands of Canadian dollars, except per Trust Unit amounts)*	**2004**	2003 *(Restated, Note 3)*
Cash provided by (used in)		
Operating Activities		
Net income for the year	**$ 18,231**	$ 15,516
Items not requiring cash		
Depletion, depreciation and accretion	**102,776**	35,727
Unrealized foreign exchange (gain) loss	**(5,537)**	1,432
Amortization of deferred finance charges	**4,086**	2,556
Unrealized loss on derivative contracts [Note 16]	**11,274**	–
Future income tax recovery	**(10,362)**	(8,978)
Non-cash unit right compensation expense	**9,535**	239
	130,003	46,492
Settlement of asset retirement obligations	**(929)**	(577)
Change in non-cash working capital	**(11,103)**	(12,290)
	117,971	33,625
Financing Activities		
Issue of Trust Units, net of issue costs	**164,743**	61,691
Issue of bridge note payable	**–**	25,000
Repayment of bridge notes	**–**	(25,000)
Issue of equity bridge notes [Notes 10 and 17]	**30,000**	33,500
Repayment of equity bridge notes [Notes 10 and 17]	**(55,000)**	(8,500)
Interest on equity bridge notes	**(1,070)**	(870)
Issuance of convertible debentures [Note 14]	**160,000**	–
Issue costs for convertible debentures	**(7,201)**	–
Interest on convertible debentures	**(5,223)**	–
Issue of senior notes	**311,951**	–
Repayment of bank debt, net	**(44,661)**	15,263
Repayment of promissory note payable	**–**	(850)
Financing costs	**(13,770)**	(2,334)
Cash distributions	**(47,074)**	(18,488)
Change in non-cash working capital	**5,097**	2,889
	497,792	82,301
Investing Activities		
Additions to capital assets	**(42,662)**	(27,209)
Acquisition of Storm Energy Ltd.	**(75,783)**	–
Property acquisitions	**(513,865)**	(93,549)
Change in non-cash working capital	**16,547**	329
	(615,763)	(120,429)
Decrease in cash and short-term investments	**–**	(4,503)
Cash and short term investments, beginning of year	**–**	4,503
Cash and short term investments, end of year	**$ –**	$ –
Cash interest payments	**$ 5,521**	$ 2,866
Cash tax payments	**$ 2,298**	$ 157
Cash distributions declared per Trust Unit	**$ 2.40**	$ 2.40

See accompanying notes to these consolidated financial statements.

Notes to Consolidated Financial Statements

December 31, 2004 and 2003

(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 formed under the laws of Alberta. Pursuant to its trust indenture and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp. ("Harvest Operations"). The Trust acquires and holds net profit interests in oil and natural gas properties in Alberta, Saskatchewan and British Columbia held by Harvest Operations and other operating subsidiaries of the Trust. All properties under the Trust are operated by Harvest Operations.

The beneficiaries of the Trust are the holders of Trust Units. The Trust makes monthly distributions of its distributable cash to Unitholders of record on the last business day of each calendar month.

2. Significant Accounting Policies

These consolidated financial statements of Harvest Energy Trust 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 they affect the Trust, these differences are described in Note 20. Certain comparative figures have been reclassified to conform to the current period's presentation.

(a) Consolidation

These consolidated financial statements include the accounts of the Trust, its wholly-owned subsidiaries and its 60% interest in a partnership with a third party. All inter-entity transactions and balances have been eliminated upon consolidation. The Trust's proportionate interest in the partnership has been included in the consolidated financial statements.

(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 of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates are subject to measurement uncertainty. In the opinion of management, these consolidated financial statements have been prepared within reasonable limits of materiality.

(c) Revenue Recognition

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

(d) Joint Venture Accounting

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

(e) Capital Assets

Oil and Natural Gas Activities

The Trust follows the full cost method of accounting for its oil and natural gas activities. All costs of acquiring oil and natural gas properties and related 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. Renewals and enhancements that extend the economic life of the capital assets are capitalized.

Gains and losses are not recognized on disposition of oil and natural gas properties unless that disposition would alter the rate of depletion by 20% or more.

Provision for depletion and depreciation of oil and natural gas assets is calculated on the unit-of-production method, based on proved reserves net of royalties as estimated by independent petroleum engineers. The basis used for the calculation of the provision is the capitalized costs of oil 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 Trust places a limit on the aggregate carrying value of capital assets associated with oil and natural gas activities, which may be amortized against revenues of future periods. Impairment is recognized if the carrying amount of the capital assets exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third-party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust 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. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Trust's future cash flows would be a permanent impairment and reflected in net income for the relevant period.

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 at rates ranging from 20% to 50% per annum.

(f) 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 the acquired business. The goodwill balance is assessed for impairment annually at year-end, or more frequently if events or changes in circumstances occur that more likely than not reduce the fair value of the acquired business below its carrying amount. The test for impairment is carried out by comparing the carrying amount of the reporting entity to its fair value. If the fair value of the Trust's equity is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to its identifiable assets and liabilities at their fair values. The excess of this allocation is the fair value of goodwill. Any excess of the book value of goodwill over this implied fair value is the impairment amount. 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 Obligation

The Trust records the fair value of an asset retirement obligation 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. The Trust 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 unit of production method over estimated net proved reserves. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

(h) Income Taxes

The Trust and its Trust subsidiaries are taxable entities under the Income Tax Act (Canada) and 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 the Income Tax Act (Canada), neither the Trust nor its Trust subsidiaries make provisions for future income taxes.

Harvest Operations and the corporate subsidiaries of the Trust follow 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 its financial statements and its respective tax base, 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

The Trust determines compensation expense for the Trust Unit incentive plan and the Unit award incentive plan [Note 12] 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 market value of the Units and the exercise price of the right. The intrinsic value is used to determine compensation expense as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment equal to the excess of the market value over the exercise price. As the expense is determined based on the period end price, large fluctuations, even recoveries, in compensation expense may occur. As the Unit rights are exercised, cash payments are reflected against the liability previously recorded and any Unit issuances are reflected as increases to Unitholders' capital.

Under the terms of the plan, the exercise price of rights granted may be reduced in future periods based on the distributions made to Trust Unitholders.

The Trust previously used the fair value method of accounting for the Trust Unit incentive plan.

(j) Exchangeable Shares

Exchangeable shares are presented as equity of the Trust as their features make them economically equivalent to Trust Units.

(k) Deferred Financing Charges

Deferred financing charges relate to costs incurred on the issuance of debt and are amortized on a straight-line basis over the term of the debt, and are included in interest expense.

(l) Financial Instruments

Derivative financial instruments are utilized by the Trust in the management of its commodity price, foreign currency and interest rate exposures. The Trust uses a variety of derivative instruments to manage these exposures including, swaps, options and collars. The Trust may elect to use hedge accounting when there is a high degree of correlation between the price movements in the derivative financial instruments and the items designated as being hedged. The Trust documents all relationships between hedging instruments and hedged items as well as its risk management objective and strategy for undertaking various hedge transactions. Gains and losses are recognized on the derivative financial instruments in the same period in which the gains and losses on the hedged item are recognized. If the price movements in the derivative instrument and the hedged item cease to be highly correlated, hedge accounting is terminated and the fair value of the derivative financial instrument at such time is recognized on the balance sheet as a deferred charge and recognized in income in the period in which the underlying hedged transaction is recognized. Future changes in the market value of the derivative financial instrument are then recognized in income as they occur. At December 31, 2004, the Trust has not designated any of its outstanding derivative instruments as hedges.

For derivative transactions where hedge accounting is not applied, the Trust applies a fair value method of accounting by initially recording an asset or liability, and recognizing changes in the fair value of the derivative instrument in income as an unrealized gain or loss on derivative contracts. Any realized gains or losses on derivative contracts that are not designated hedges are recognized in income in the period they occur.

(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 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) *Full Cost Accounting Guideline*

Effective January 1, 2004, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Accounting Guideline 16 *"Oil and Gas Accounting – Full Cost"*. The changes under the new guideline include modifications to the ceiling test and depletion and depreciation calculations. There were no changes to previously reported net income, capital assets or any other financial statement amounts as a result of the implementation of this guideline.

(b) *Asset Retirement Obligations*

Effective January 1, 2004, the Trust adopted CICA Handbook Section 3110 *"Asset Retirement Obligations"* in accounting for its asset retirement obligations.

The effect of this change in accounting policy has been recorded retroactively with restatement of prior periods as follows:

Balance Sheet	As at December 31, 2003
Asset retirement costs, included in capital assets	$ 35,166
Asset retirement obligation	42,009
Site restoration provision	(4,321)
Future income tax asset	1,024
Accumulated income	(1,498)

Income Statement	Year Ended December 31, 2003
Accretion expense	$ 1,845
Depletion and depreciation on asset retirement costs	4,520
Site restoration and reclamation	(4,355)
Future tax recovery	(816)
Net income change	(1,194)
Basic net income change per Trust Unit	(0.10)
Diluted net income change per Trust Unit	(0.09)

(c) *Financial Instruments*

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 *"Hedging Relationships"* ("AcG-13"). This guideline addresses the identification, designation and effectiveness of financial contracts for the purpose of applying hedge accounting. Under this guideline, financial derivative contracts must be designated to the underlying revenue or expense stream that they are intended to hedge, and tested to ensure they remain sufficiently effective. For transactions that do not qualify as designated hedges, the Trust applies a fair value method of accounting by initially recording an asset or liability, and recognizing changes in the fair value of the derivative instrument in income.

Upon the implementation of this new accounting policy, the Trust recorded a liability and a corresponding asset of $5.5 million related to the fair value of the derivative financial instruments that did not qualify for hedge accounting. This amount has been fully recognized in income for the year ended December 31, 2004.

4. Corporate Acquisitions

On June 30, 2004, the Trust completed a Plan of Arrangement with Storm Energy Ltd. ("Storm"). Under this plan, the Trust acquired certain oil 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 11] and the issuance of 600,587 exchangeable shares each at $14.77 [Note 13], $75 million in cash, the assumption of approximately $67.3 million in debt and working capital deficiency and acquisition costs of $0.8 million. This transaction has been accounted for using the purchase price 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	$ (10,488)
Bank debt	(56,831)
Capital assets	213,455
Derivative contract	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

On June 1, 2003, the Trust acquired all of the common shares and the Net Profit Interest of a private company. Total consideration paid by the Trust was $10.1 million, and consisted of the issuance of 625,000 Trust Units at a price of $10.00 per Trust Unit, $3 million in cash and an $850,000 unsecured demand promissory note bearing an interest rate of 10% per annum effective June 27, 2003. The Trust assumed $2.5 million of working capital, $2.8 million of bank debt and acquired $15.4 million in capital assets as part of this acquisition.

5. Capital Assets

December 31, 2004	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil 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**

December 31, 2003	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 202,529	$ (31,262)	$ 171,267
Production facilities and equipment	47,071	(8,346)	38,725
Office furniture and equipment	708	(157)	551
Total	$ 250,308	$ (39,765)	$ 210,543

On September 2, 2004, the Trust purchased oil and natural gas producing properties from a senior producer for cash consideration of approximately $526 million before final working capital adjustments. Final adjustments reduced the Trust's purchase price to $511.4 million. In conjunction with the acquisition of these properties, the Trust issued approximately $175.2 million in subscription receipts which were converted into 12,166,666 Trust Units upon completion of the purchase [Note 11], and $100 million in 8% convertible unsecured subordinated debentures [Note 14]. The balance of the acquisition cost was funded with a new credit facility arrangement [Note 8].

On October 16, 2003, the Trust acquired the Carlyle Properties in southeastern Saskatchewan for total consideration of approximately $79.5 million before costs and purchase price adjustments. The acquisition was partially financed by the issue of Trust Units on October 16, 2003, with the balance being funded by the bank facility.

General and administrative costs of $3.6 million (2003 – $1.3 million) have been capitalized during the year ended December 31, 2004.

All costs are subject to depletion and depreciation at December 31, 2004 including future development costs of $83.3 million (2003 – $15.2 million). $28.6 million (2003 – nil) of undeveloped properties were excluded from the asset base subject to depletion at December 31, 2004.

In accordance with Canadian GAAP, the Trust performed an impairment test as at December 31, 2004 and 2003. The crude oil and natural gas future prices used in the impairment test were obtained from third parties and were adjusted for commodity price differentials specific to the Trust. Based on these assumptions, the undiscounted future net revenue from the Trust's proved reserves exceed the carrying value of the Trust's oil and natural gas assets as at December 31, 2004, and therefore no impairment was recorded.

Benchmark Prices	WTI Oil (U.S.$/bbl)	Foreign Exchange Rate	Edmonton Light Crude Oil (CDN$/bbl)	AECO Gas (CDN$/GJ)
Year				
2005	42.00	0.83	49.60	6.45
2006	39.50	0.83	46.60	6.20
2007	37.00	0.83	43.50	6.05
2008	35.00	0.83	41.10	5.80
2009	34.50	0.83	40.50	5.70
Thereafter (escalation)	2.0%	0%	2.0%	2.0%

6. Accounts Payable and Accrued Liabilities

As at December 31	**2004**	2003
Trade accounts payable	**$ 13,697**	$ 9,524
Accrued interest	**5,993**	897
Trust Unit incentive plans [Note 12]	**9,774**	–
Premium on derivative contracts	**4,500**	–
Accrued closing adjustments on asset acquisition	**13,546**	–
Other accrued liabilities	**27,139**	7,629
Large corporation taxes payable	**1,602**	33
	$ 76,251	$ 18,083

7. Asset Retirement Obligation

The Trust's asset retirement obligation results from its net ownership interest in oil 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 $334.8 million which will be incurred between 2004 and 2023. The majority of the costs will be incurred between 2015 and 2021. A credit-adjusted risk-free rate of 10% was used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

Year Ended December 31	**2004**	2003
Balance, beginning of year	**$ 42,009**	$ 15,566
Liabilities incurred	**53,488**	25,175
Revision of estimates	**(8,704)**	–
Liabilities settled	**(929)**	(577)
Accretion expense	**4,221**	1,845
Balance, end of year	**$ 90,085**	$ 42,009

8. Bank Debt

As at December 31, 2004, Harvest Operations has a senior borrowing base credit facility with a syndicate of lenders. This facility consists of a $310 million production loan, a $15 million operating loan, and a U.S. $21.3 million mark-to-market credit to be used for financial instrument hedging. The term of the facility is to June 29, 2005. Availability under the facility is subject to a borrowing base calculation performed by the lenders at least on a semi-annual basis. The facility permits drawings in Canadian or U.S. dollars, and includes banker's acceptances, LIBOR loans and letters of credit. Outstanding balances bear interest at rates ranging from 0% to 2.25% above the applicable Canadian or U.S. prime rate depending upon the type of borrowing and the debt to annualized cash flow ratio. The debt is secured by a $750 million debenture with a fixed and floating charge over all of the assets of Harvest Operations, and a guarantee by the Trust and its subsidiaries.

A bridge facility of $70 million was provided by the Trust's lenders to assist in the closing of the significant property acquisition in September [Note 5]. This facility was due to mature on June 1, 2005, and outstanding balances under this facility accrued interest at progressive rates of 3% to 8% above the applicable Canadian prime rate. The bridge facility was repaid in full with the net proceeds of the senior notes issuance [Note 9].

9. Senior Notes

On October 14, 2004, Harvest Operations closed an agreement to sell, on a private placement basis in the United States, U.S.$250 million of senior notes due October 15, 2011. The senior notes are unsecured and bear interest at an annual rate of 7 7/8% and were sold at a price of 99.3392% of their principal amount. A discount of $2.1 million on the senior notes is recorded in deferred charges and amortized into interest expense over the term of the notes. Interest is payable semi-annually on April 15 and October 15. The senior notes are unconditionally guaranteed by the Trust and all of its wholly-owned subsidiaries. The Trust used the net proceeds of the offering to repay in full Harvest's bank bridge facility and partially repay outstanding balances under Harvest's senior credit facility. The fair value of the senior notes at December 31, 2004 was U.S.$250.6 million (Cdn$301.2 million).

10. Equity Bridge Notes

A director of Harvest Operations and a corporation controlled by that director had advanced $25 million pursuant to the equity bridge notes as at December 31, 2003. 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 principal amount and paid $185,232 of interest accrued since December 31, 2003. The notes were amended on June 29, July 7 and July 9, 2004. These notes were drawn by $30 million 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 interest of the senior secured lenders pursuant to Harvest Operations' credit facility.

The Trust had the option to settle the quarterly interest payments under the equity bridge notes with cash or the issue of Trust Units. If the Trust elected to issue Trust Units, the number of Trust Units to be issued to settle a quarterly interest payment would have been the equivalent of the quarterly payment amount divided by 90% of the most recent ten-day weighted average trading price. The Trust had the option at maturity of the notes to settle the principal obligation with cash or with the issue of Trust Units. The terms to settle principal with Units is the same as with the interest option described above.

11. Unitholders' Capital

(a) *Authorized*

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

(b) *Issued*

	Number of Units (000s)	Amount
As at December 31, 2002	9,312	$ 36,728
Exercise of warrants	150	150
Special warrant exercise	1,500	15,000
Acquisitions	825	8,350
Trust Unit issue	4,313	48,645
Distribution reinvestment plan issuance	1,009	10,638
Trust Unit issue costs	–	(2,104)
As at December 31, 2003	17,109	$ 117,407
Storm Plan of Arrangement [Note 4]	2,721	40,183
Conversion of subscription receipts [Note 5]	12,167	175,200
Convertible debenture conversions – 9% series	3,521	49,300
Convertible debenture conversions – 8% series	5,221	84,841
Exchangeable share retraction	152	2,142
Distribution reinvestment plan issuance	752	12,553
Unit appreciation rights exercise	145	721
Trust Unit issue costs	–	(17,216)
As at December 31, 2004	41,788	$ 465,131

(c) *Per Trust Unit Information*

The following table summarizes the net income and Trust Units used in calculating income per Trust Unit:

	2004	2003
Net income adjustments		
Net income	**$ 18,231**	$ 15,516
Interest on equity bridge notes	**(1,070)**	(870)
Interest on convertible debentures	**(5,223)**	–
Net income available to Trust Unitholders	**$ 11,938**	$ 14,646
Weighted average Trust Unit adjustments		
Weighted average Trust Units outstanding	**25,033,567**	12,590,937
Weighted average exchangeable shares outstanding(1)	**290,090**	–
Weighted average Trust Units outstanding, basic	**25,323,657**	12,590,937
Effect of Trust Unit appreciation rights	**1,140,738**	411,868
Weighted average Trust Units outstanding, diluted (2)	**26,464,395**	13,002,805

(1) Reflects the weighted average of exchangeable shares outstanding based on the conversion ratio at December 31, 2004.

(2) Weighted average Trust Units outstanding diluted for 2004 does not include the impact of the conversion of the debentures as the impact would be anti-dilutive. Total Units excluded amount to 6,004,145.

12. Trust Unit Incentive Plans

The Trust Unit incentive plan was established in 2002. In December 2004, the plan was modified such that the ability to settle a Unit right with cash is now solely at the option of the holder and not subject to the discretion of the Board of Directors. The Trust is authorized to grant non-transferable rights to purchase Trust Units to directors, officers, consultants, employees and other service providers to an aggregate of 1,487,250 Trust Units, of which 1,371,475 were granted as of December 31, 2004. 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 vested 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, the Trust is required to recognize an obligation for all of 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 Unit rights outstanding under the plan. As such, an obligation of $9.8 million has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 1,117,725 Trust Units outstanding under the plan at December 31, 2004. A one time charge of $8.2 million has been included in Unit right compensation expense to reflect the additional expense resulting from the change in accounting from the fair value method previously used to the intrinsic method. The amount previously expensed has been removed from contributed surplus and reflected in accounts payable and accrued liabilities.

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

	2004		2003	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price [a]
Outstanding beginning of year	**1,065,150**	**$ 9.04**	787,500	$ 8.00
Granted	**445,600**	**16.47**	277,650	11.94
Exercised	**(253,750)**	**8.30**	–	–
Cancelled	**(139,275)**	**10.91**	–	–
Outstanding before exercise price reductions	**1,117,725**	**11.92**	1,065,150	9.04
Exercise price reductions	**–**	**(1.83)**	–	(1.11)
Outstanding, end of year	**1,117,725**	**$ 10.09**	1,065,150	$ 7.93
Exercisable before exercise price reductions	**206,688**	**$ 8.89**	196,875	$ 8.00
Exercise price reductions	**–**	**(2.64)**	–	(1.30)
Exercisable, end of year	**206,688**	**$ 6.25**	196,875	$ 6.70

(a) adjusted to retroactively reflect modifications to the plan made in 2004.

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2004.

		Outstanding			Exercisable	
Exercise Price Before Price Reductions	Exercise Price Net of Price Reductions	Outstanding at December 31, 2004	Exercise Price Net of Price Reductions [a]	Remaining Contractual Life [a]	Exercisable at December 31, 2004	Exercise Price Net of Price Reductions [a]
$8.00 – 10.21	$5.18 – $7.86	509,625	$ 5.27	2.9	163,375	$ 5.23
$10.30 – $13.35	$7.98 – $11.97	214,700	10.31	3.7	43,313	10.11
$13.75 – $18.90	$12.37 –$18.50	308,400	14.92	4.5	–	n/a
$19.90 – $23.70	$19.50 – $23.30	85,000	20.92	4.8	–	n/a
$8.00 – $23.70	$5.18 – $23.30	1,117,725	$ 10.09	3.7	206,688	$ 6.25

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

When the Trust adopted the fair value method of accounting for its Trust Unit incentive plan on January 1, 2003, it was required to calculate the pro forma impact of having adopted that method from the date all rights were initially granted.

For purposes of those calculations the fair value of each Trust Unit right has been estimated on the grant date using the following:

	December 31, 2003
Expected volatility	23.3%
Risk free interest rate	4.1%
Expected life of the Trust Unit rights	4 years
Estimated annual distributions per Unit	$ 2.40

As at December 31, 2003 for the purposes of pro forma disclosures, the expense related to all of the Trust Unit rights issued prior to December 31, 2002 is reflected in proforma net income as shown below:

		2003
		(Restated, Note 3)
Net income	As reported	$ 15,516
	Pro forma	$ 14,228
Income per Unit – basic	As reported	$ 1.16
	Pro forma	$ 1.06
Income per Unit – diluted	As reported	$ 1.13
	Pro forma	$ 1.03

During the years ended December 31, the Trust has recognized non-cash compensation expense of $9.5 million in 2004 and $239,000 in 2003 related to Trust Unit rights and included it in general and administrative expense in the consolidated statements of income.

Unit Award Incentive Plan

In the year ended December 31, 2004, the Trust has 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. The Trust recorded compensation expense of $56,000 in 2004 related to this plan. The Trust may issue up to a maximum of 150,000 Trust Units under the Unit Award Plan. In 2004, 15,000 Trust Units were issued under this plan, of which 5,000 were subsequently cancelled.

13. 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	Number	Amount
Storm Plan of Arrangement	600,587	$ 8,870
Shareholder retractions	(145,040)	(2,142)
As at December 31, 2004	455,547	$ 6,728

On June 30, 2004, 600,587 exchangeable shares, series 1 were issued at $14.77 each as partial consideration under the Plan of Arrangement with Storm [Note 4]. 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. The exchangeable shares had an exchange ratio of 1:1.06466 as at December 31, 2004.

14. Convertible Debentures

On January 29, 2004, the Trust issued $60 million of 9% convertible unsecured subordinated debentures due May 31, 2009. Interest on the debentures is payable semi-annually in arrears in equal installments on May 31 and November 30 in each year, commencing May 31, 2004. 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 May 31, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $14.00 per Trust Unit plus a cash payment for accrued interest and in lieu of any fractional Trust Units resulting on the conversion. The debentures may be redeemed by the Trust at its option in whole or in part subsequent to May 31, 2007, at a price equal to $1,050 per debenture between June 1, 2007 and May 31, 2008 and at $1,025 per debenture between June 1, 2008 and May 31, 2009. Any redemption will include accrued and unpaid interest at such time. Under both redemption options, the Trust may elect to pay both the principal and accrued interest 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.

On August 10, 2004, the Trust issued of $100 million of 8% convertible unsecured subordinated debentures due September 30, 2009. Interest on the debentures is payable semi-annually in arrears in equal installments on March 31 and September 30 in each year, commencing March 31, 2005. 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 September 30, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the debentures, at a conversion price of $16.25 per Trust Unit plus a cash payment for accrued interest and in lieu of any fractional Trust Units resulting on the conversion. The debentures may be redeemed by the Trust at its option in whole or in part subsequent to September 30, 2007, at a price equal to $1,050 per debenture between October 1, 2007 and September 30, 2008 and at $1,025 per debenture between October 1, 2008 and September 30, 2009. Any redemption will include accrued and unpaid interest at such time. Under both redemption options, the Trust may elect to pay both the principal and accrued interest 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. This series of convertible debentures ranks pari-passu with the outstanding debentures issued on January 29, 2004.

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

	9% Series		8% Series		Total
	Number of Debentures	Amount	Number of Debentures	Amount	Amount
January 29, 2004 issuance	60,000	$ 60,000	–	–	$ 60,000
August 10, 2004 issuance	–	–	100,000	$ 100,000	100,000
Converted for Trust Units	(49,300)	(49,300)	(84,841)	(84,841)	(134,141)
Convertible debenture issue costs		(2,667)		(4,534)	(7,201)
Convertible debenture issue costs related to the converted debentures		2,184		3,854	6,038
As at December 31, 2004	10,700	$ 10,217	15,159	$ 14,479	$ 24,696
Fair value at December 31, 2004		$ 17,441		$ 21,223	$ 38,664

15. Income Taxes

Future income taxes reflect 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. 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.

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:

		2004		2003
Income before taxes	$	9,374	$	6,695
Multiplied by tax rate		38.9%		40.6%
Computed income tax expense at statutory rates	$	3,646	$	2,718
Amount included in Trust income		(17,433)		(13,293)
		(13,787)		(10,575)
Increase (decrease) resulting from the following:				
Non-deductible crown charges		1,278		(61)
Resource allowance		(1,731)		2,062
Non-tax portion of capital gain		2,633		(1,282)
Unit appreciation rights expense		560		99
Rate change		549		794
Other		136		(15)
Future income tax recovery	$	(10,362)	$	(8,978)

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

		2004		2003
Net book value of oil and natural gas assets in excess of tax pools	$	46,333	$	(1,085)
Asset retirement obligation		(9,691)		(9,468)
Net unrealized gains on derivative contracts and foreign exchange		2,293		–
Tax loss carry forwards		(1,172)		(1,649)
Deferral of taxable income in partnership		2,339		–
Working capital and other items		(5,431)		(407)
Future income tax liability (asset)	$	34,671	$	(12,609)

The non-capital losses described above expire in the years 2009 and 2010.

16. Financial Instruments

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, deposits, accounts payable and accrued liabilities, cash distributions payable, bank debt, convertible debentures and senior notes. Other than as disclosed in the related notes to the convertible debentures and the senior notes, 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

(b) Interest Rate Risk

The Trust is exposed to interest rate risk on its bank debt. All of the Trust's other debt has fixed interest rates.

(c) Credit Risk

Substantially all accounts receivable are due from customers in the oil 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 senior notes are denominated in U.S. dollars (U.S.$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, 2004 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) *Commodity Risk Management*

The Trust uses fixed price oil sales contracts and derivative financial instruments to manage its commodity price exposure. Under the terms of some of the derivative instruments, Harvest Operations is required to provide security from time to time based on the underlying market value of those contracts. The Trust is also exposed to counterparty risk for these derivative contracts. This risk is managed by diversifying the Trust's derivative portfolio among a number of counterparties and by dealing with large investment grade institutions.

The following is a summary of the oil sales price derivative contracts as at December 31, 2004, that have fixed future sales prices:

Oil Price Swap Contracts Based on West Texas Intermediate

Daily Quantity	Term	Price per Barrel	Mark-to-Market Gain (Loss)
500 bbl/d	January through December 2005	U.S.$24.00	$ (4,107)
1,100 bbl/d	January through March 2005	U.S.$22.38	(2,535)
1,030 bbl/d	April through June 2005	U.S.$22.18	(2,358)
50% Participating Swap Contracts Based on West Texas Intermediate			
8,750 bbl/d	January through December 2006	U.S.$38.16 (b)	$ 3,710
Oil Price Collar Contracts Based on West Texas Intermediate			
2,500 bbl/d	January through June 2005	U.S.$28.40 – 32.25 ($21.80)	$ (6,032) (a)
1,500 bbl/d	July through December 2005	U.S.$28.17 – 32.10 ($22.33)	(3,296) (a)
2,000 bbl/d	January through December 2005	U.S.$28.00 – 42.00	(529)

(a) Harvest has sold put options at the average price denoted in parenthesis, for the same volumes as the associated commodity contracts. The counterparty may exercise these options if the respective index falls below the specified price on a monthly settlement basis.

(b) This price is a floor. The Trust realizes this price plus 50% of the difference between spot price and this price.

Indexed Put Options Based on West Texas Intermediate

Daily Quantity	Term	Type	Price per Barrel ($U.S.)	Mark-to-Market Gain (Loss)
4,000 bbl/d	January through December 2005	Long Put	30.00	$ 937
1,972 bbl/d	January through December 2005	Short Call	30.00	(11,261)
1,972 bbl/d	January through December 2005	Long Call	40.00	4,642
7,000 bbl/d	January through December 2005	Long Put	35.00	4,050
2,380 bbl/d	January through December 2005	Short Call	35.00	(9,239)
2,380 bbl/d	January through December 2005	Long Call	45.00	3,090
7,500 bbl/d	January through December 2005	Long Put	40.00	9,142
3,675 bbl/d	January through December 2005	Short Call	40.00	(8,651)
3,675 bbl/d	January through December 2005	Long Call	50.00	2,678
7,500 bbl/d	January through June 2006	Long Put	34.00	2,989
3,750 bbl/d	January through June 2006	Short Call	34.00	(7,252)
3,750 bbl/d	January through June 2006	Long Call	44.00	3,170

(1) Each group of a long put, short call and a long call reflect an "indexed put option". These series of puts and calls serve to fix a floor price while retaining upward price exposure on a portion of price movements above the floor price.

The following is a summary of electricity price physical and financial swap contracts entered into by Harvest Operations to fix the cost of future electricity usage as well as a put option related to the U.S./Canadian dollar exchange rate as at December 31, 2004:

Swap Contracts Based on Electricity Prices

Weighted Average Quantity	Term	Average Price per Megawatt	Mark-to-Market Gain (Loss)
24.8 MWh	January through December 2005	$47.43	$ 1,272
29.9 MWh	January through December 2006	$47.51	(196)

Swap Contracts Based on Electricity Heat Rate

Quantity	Term	Heat Rate	Mark-to-Market (Loss)
5 MW	January through December 2005	8.40 GJ/MWh	$ (80)

Foreign Currency Contracts

Monthly Contract Amount	Term	Contract Rate	Mark-to-Market Gain
U.S.$8.33 million	January through December 2005	1.20 Cdn / U.S.	$ 4,500 [1]

(1) Represents the premium paid on this contract.

At December 31, 2004, the net unrealized loss position reflected on the balance sheet for all the financial derivative contracts outstanding at that date was approximately $15.4 million. Harvest Operations has provided deposits to some counterparties for a portion of its financial derivative contracts, based on the fair value of those contracts at the end of the trading day.

For the year ended December 31, 2004, the total unrealized loss recognized in the statement of income was $11.3 million. The realized losses on all derivative contracts are included in the period in which they are incurred. Both of these amounts are reflected in Gains and Losses on Derivative Contracts on the statement of income.

At October 1, 2004, the Trust discontinued hedge accounting for all of its derivative financial instruments. For those contracts where hedge accounting had previously been applied, a deferred charge or gain was recorded equal to the fair value of the contracts at the time hedge accounting was discontinued with a corresponding amount recorded in the derivative contracts balance. The deferred charge or gain is recognized in income in the period in which the underlying transaction is recognized.

For the year ended December 31, 2004, $14.9 million of the deferred charge and $350,000 of the deferred gain has been amortized and recorded in gains and losses on derivative contracts in the statement of income. At December 31, 2004, $10.8 million and $2.2 million has been recorded as a deferred charge and a deferred gain, respectively on the balance sheet.

	December 31	
Deferred Charges – Asset	**2004**	2003
Balance, beginning of year	**$ 1,989**	$ 2,210
Deferred charge related to derivative contracts recorded upon adoption of AcG-13	**5,490**	–
Deferred charge related to derivative contracts recorded upon discontinuing hedge accounting	**20,215**	–
Discount on senior notes [Note 9]	**2,075**	–
Financing costs incurred	**13,770**	2,335
Amortization of deferred charge related to derivative contracts [1]	**(14,946)**	–
Amortization of deferred financing costs [2]	**(4,086)**	(2,556)
Balance, end of year	**$ 24,507**	$ 1,989

Deferred Gains – Liability	December 31 2004	2003
Balance, beginning of year	$ –	$ –
Deferred gains related to derivative contracts recorded upon discontinuing hedge accounting	2,527	–
Amortization of deferred gains related to derivative contracts [1]	(350)	–
Balance, end of year	$ 2,177	$ –

(1) Recorded within gains and losses on derivative contracts

(2) Recorded within interest expense

17. Related Party Transactions

Refer to Note 10 regarding equity bridge notes received from a director of Harvest Operations and a corporation controlled by that director.

A corporation controlled by a director of Harvest Operations sublets office space and is provided administrative services by Harvest Operations on a cost recovery basis.

18. Change in Non-Cash Working Capital

Year Ended December 31	2004	2003
Changes in non-cash working capital items:		
Accounts receivable	$ (24,860)	$ (5,590)
Prepaid expenses and deposits	9,117	(11,596)
Current portion of derivative contract assets	(8,861)	–
Accounts payable and accrued liabilities	58,168	12,154
Cash distributions payable	4,936	1,559
Current portion of derivative contracts liability	27,927	–
	$ 66,427	$ (3,473)
Changes relating to operating activities	$ (11,103)	$ (12,290)
Changes relating to financing activities	5,097	2,889
Changes relating to investing activities	16,547	329
Add: Non cash changes	55,886	5,599
	$ 66,427	$ (3,473)

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 the Trust 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 affect on the Trust's reported financial position or results from operations.

The Trust has letters of credit outstanding in the amount of approximately $5 million related to electricity infrastructure usage. These letters are provided by Harvest Operations' lenders pursuant to the credit agreement [Note 8]. These letters expire throughout 2004 and 2005, and are expected to be renewed as required.

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2004:

	Payments Due by Period				
	2005	2006 – 2007	2008 – 2009	Thereafter	Total
Debt repayments [(1)]	$ 75,519	–	–	$ 300,500	$ 376,019
Capital commitments	700	–	–	–	700
Operating leases	400	$ 2,869	$ 2,869	956	7,094
Total contractual obligations	$ 76,619	$ 2,869	$ 2,869	$ 301,456	$ 383,813

(1) Includes long-term and short-term debt. Assumes that the outstanding convertible debentures either exchange at the holders' option for Units or are redeemed for Units at the Trust's option.

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 generally accepted accounting principles in 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 below. All items required for financial disclosure under U.S. GAAP are not noted.

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

Year Ended December 31	**2004**	2003
Net income as reported	**$ 18,231**	$ 15,516
Adjustments		
Unrealized loss on derivative financial instruments (f)	**3,886**	(9,345)
Future income tax effect on unrealized loss on derivative financial instruments (f) (g)	**(5,251)**	3,952
Future income tax impact of deferred charges (f) (g)	**2,885**	–
Interest on convertible debentures (d)	**(5,223)**	–
Interest on equity bridge notes (d)	**(1,070)**	(870)
Amortization of deferred financing charges (d)	**(546)**	–
Non-cash general and administrative expenses (c)	**1,455**	(1,288)
Net income under U.S. GAAP before cumulative effect of change in accounting policy	**14,367**	7,965
Cumulative effect of change in accounting policy (b)	**–**	(304)
Net income under U.S. GAAP after cumulative effect of change in accounting policy	**14,367**	7,661
Increase in redemption value of Trust Units under U.S. GAAP (e)	**(298,893)**	(48,362)
Net loss available to Unitholders under U.S. GAAP (e)	**$ (284,526)**	$ (40,701)
Basic		
Net income under U.S. GAAP before cumulative effect of change in accounting policy	**$ 0.57**	$ 0.63
Cumulative effect of change in accounting policy (b)	**–**	(0.02)
Net income after the cumulative effect of change in accounting policy (before changes in redemption value of Trust Units)	**$ 0.57**	$ 0.61
Net loss available to Unitholders per Trust Unit under U.S. GAAP	**$ (11.24)**	$ (3.23)
Diluted		
Net income under U.S. GAAP before cumulative effect of change in accounting policy	**$ 0.54**	$ 0.61
Cumulative effect of change in accounting policy	**–**	(0.02)
Net income after the cumulative effect of change in accounting policy (before changes in redemption value of Trust Units)	**$ 0.54**	$ 0.59
Net loss available to Unitholders per Trust Unit under U.S. GAAP	**$ (11.24)**	$ (3.23)

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

	December 31, 2004		December 31, 2003	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets				
Current portion of derivative contracts (f)	**$ 8,861**	**$ 8,861**	$ –	$ –
Capital assets (a)	**918,397**	**918,397**	210,543	210,543
Long-term portion of derivative contracts (f)	**3,710**	**3,710**	–	–
Deferred charges (f) (d)	**24,507**	**12,768**	1,989	1,989
Future income tax (g)	**–**	**–**	12,609	17,860
Liabilities				
Derivative contracts (f)	**27,927**	**27,927**	–	12,468
Deferred gains (f)	**2,177**	**–**	–	–
Senior notes (i)	**300,500**	**298,488**	–	–
Convertible debentures – liability (d)	**–**	**25,859**	–	–
Equity bridge notes – liability (d)	**–**	**–**	–	25,000
Asset retirement obligation (b)	**90,085**	**90,085**	42,009	42,009
Future income tax (f) (g)	**34,671**	**31,786**	–	–
Temporary equity (e)	**–**	**867,452**	–	213,692
Unitholders' equity				
Unitholders' capital (e)	**465,131**	**–**	117,407	–
Equity bridge notes (d)	**–**	**–**	25,000	–
Convertible debentures (d)	**24,696**	**–**	–	–
Exchangeable shares (e)	**6,728**	**–**	–	–
Contributed surplus (c)	**–**	**–**	239	1,694
Accumulated income (loss)	**31,416**	**(370,005)**	19,478	(85,479)

(a) Under Canadian GAAP, the Trust performs an impairment test that limits the capitalized costs of its oil and natural gas assets to the discounted estimated future net revenue from proved and risked probable oil and natural gas reserves plus the cost of unproved properties less impairment, using forward prices. The discount rate used is equal to the Trust's risk free interest rate. Under U.S. GAAP, entities using the full cost method of accounting for oil and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved oil and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP ceiling tests are those in effect at year end. There was no impairment under U.S. GAAP at December 31, 2004 or 2003.

(b) Effective January 1, 2004, the Trust retroactively adopted the CICA Handbook standard for accounting for asset retirement obligations. This section is equivalent to Statement of Financial Accounting Standards ("SFAS") No. 143 for fiscal periods beginning on or after January 1, 2003. The transitional provisions between Canadian GAAP and U.S. GAAP differ however, as Canadian GAAP requires a restatement of comparative amounts whereas U.S. GAAP does not allow restatement.

(c) During the year, the Trust modified the Trust Unit incentive plan to include a feature that allows participants to receive cash for the value of their Units at their sole option. As such, under Canadian GAAP the Trust now determines compensation expense based on the excess of the market price over the adjusted exercise price of all of the rights outstanding at the end of each reporting period and the expense is deferred and recognized in income over the vesting period of the rights, with a corresponding amount recorded to liabilities. After the rights have vested, compensation expense is recognized in income in the period in which a change in the market price of the Trust Units or the exercise price of the rights occurs. For the year ended December 31, 2003, under Canadian GAAP, the Trust used the fair value method to account for these rights.

For U.S. GAAP purposes, the Trust Unit incentive plan is a variable compensation plan as the exercise price of the rights is subject to downward revisions from time to time. Accordingly, compensation expense is determined using the same method as under Canadian GAAP for 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, 2003, an adjustment is also made for the difference between compensation expense using the fair value method and the intrinsic method used.

(d) Under Canadian GAAP, the equity bridge notes and convertible debentures are classified as Unitholders' equity and the interest accrued and paid on the equity bridge notes and convertible debentures has been recorded as a reduction of accumulated income. Issue costs are netted against equity and interest expense is recorded as a financing activity in the statement of cash flows.

Under U.S. GAAP, the equity bridge notes and convertible debentures are classified as long-term debt. Accordingly, an adjustment has been made to net income to reflect interest expense on both instruments under U.S. GAAP. Under U.S. GAAP the interest expense would be reported as a reduction to operating cash flows in the statement of cash flows.

Issue costs related to the convertible debentures have been classified as deferred charges for U.S. GAAP and amortized into income.

(e) Under the Trust 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. Increases, if any, in the redemption value during a period results in a charge to permanent equity and is reflected as a reduction in earnings available to Unitholders for the year.

(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 they can receive this accounting treatment. The Trust had not formally documented and designated all hedging relationships as at December 31, 2004 or December 31, 2003, and as such was not eligible for hedge accounting treatment.

Upon adoption of AcG-13, the Trust has implemented fair value accounting effective January 1, 2004 under Canadian GAAP and had designated a portion of its derivative contracts as hedges. A difference does arise due to the adoption of fair value accounting 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. During the year, the Trust discontinued hedge accounting for all derivative contracts under Canadian GAAP. Under U.S. GAAP there were no contracts designated as hedges. To the extent deferred charges and gains are recorded and amortized when hedge accounting was discontinued, there is a difference between Canadian and 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 year ended December 31, 2004 or the year ended December 31, 2003 relating to tax rate differences.

Upon adoption of fair value accounting for derivative contracts under Canadian GAAP, deferred charges and gains were set up when hedge accounting was discontinued. As there is no tax base relating to these amounts a temporary difference was created. This difference does not exist under U.S. GAAP as there are no deferred charges or gains under U.S. GAAP. In addition, to the extent there were historical differences with respect to Canadian and U.S. GAAP due to derivative contract 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.

At December 31, 2003, the difference relates to the recording of a derivative contract liability under U.S. GAAP and not under Canadian GAAP.

(h) Unless otherwise noted, the consolidated statements of cash flows prepared in accordance with Canadian GAAP conform in all material respects with U.S. GAAP, with the exception that Canadian GAAP allows for the presentation of a subtotal of cash flows from operating activities before changes in non-cash working capital items in the consolidated statement of cash flows. This sub-total cannot be presented under U.S. GAAP.

(i) 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") and the Trust has assessed the impact to be as follows:

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 interim or annual period beginning on or after June 15, 2005, for awards granted on or after the effective date. 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. Management does not expect this statement to have a material impact on its consolidated financial statements.

Additional disclosures required under U.S. GAAP:

December 31, *(thousands of Canadian dollars)*	**2004**	2003
Components of accounts receivable		
Trade	**$ 14,743**	$ 16,334
Accruals	**29,285**	2,834
	$ 44,028	$ 19,168
Components of prepaid expenses		
Prepaid expenses	**$ 1,730**	$ 232
Funds on deposit	**1,284**	11,899
	$ 3,014	$ 12,131

Corporate Information

Directors

John A. Brussa (1) (3) (4)
M. Bruce Chernoff, Chairman (2) (3)
Verne G. Johnson (1) (2) (4)
Hector J. McFadyen (1) (3) (4)
Hank B. Swartout (2)

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

Officers

Jacob Roorda, P.Eng.
President

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

James A Campbell, P. Geol.
Vice President, Geosciences

David J. Rain, C.A.
Vice President, Chief Financial Officer and Corporate Secretary

Key Personnel

J. Howard Bye
Field Superintendent, North

Renata Colic, C.A.
Manager, Financial Reporting

Randy Doetzel
Manager, Production

Darcy Erickson, P. Eng.
Manager, Drilling & Completions

Danielle Gallant, C.A.
Manager, Corporate Finance

Cindy Gray
Investor Relations & Communications

John Keirle
Manager, Land

Matthew Mazuryk, P. Eng.
Manager, Engineering

Allan Post
Operational Controller

Steve Saunders, C.A.
Director, Taxation

Robert Sayna
Field Superintendent, South

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