Harvest
ENERGY

2008 Annual Report



Focusing on Fundamentals

Harvest ENERGY

ANNUAL MEETING OF UNITHOLDERS

May 19, 2009, 3:00 p.m. (MT)
Lecture Theatre Room, Metropolitan Centre
333 4th Avenue S.W., Calgary Alberta

TSX: **HTE:UN**
NYSE: **HTE**

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KEY MESSAGES ABOUT HARVEST ENERGY

Sustainability

Harvest Energy is an integrated oil and gas company that has the opportunity to provide ongoing cashflow with substantial development opportunity. The diversity and integration provided by being active in both the upstream and downstream parts of the business, provides the long-term sustainability that optimizes our ability to create value for stakeholders through changing economic environments.

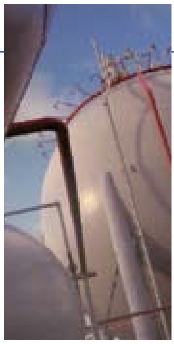
Harvest is committed to achieving efficient, sustained growth in the size and value of our upstream reserves and refining assets, while maintaining high standards for ethical conduct, the protection of health and safety, and the preservation of environmental quality. We have built the infrastructure and support systems needed to develop and optimize our upstream properties and our refining and marketing business.

Diversity

We have a natural hedge in our integrated business model and diversity in our cashflow with involvement in both upstream and downstream operations.

In our upstream oil and gas production business, Harvest uses a diverse range of technology such as enhanced oil recovery, drilling technology, pumping technology and operational practices to advance upstream growth strategies.

Our downstream business includes the refinery and a retail and wholesale marketing business. The refinery produces gasoline and heavy fuel oil and a high proportion of distillate products such as diesel and jet fuel that are in high demand. We produce some of the highest quality products in the world today for transportation fuels.



Opportunity

Harvest actively considers, evaluates and pursues opportunities to grow our asset base in a value-creating fashion through internal development of our assets as well as acquiring assets at reasonable prices that have been identified and evaluated as opportunities for growth.

Growth opportunities are expected to leverage core strengths of the existing asset base by using focus, technology and expertise to develop unrealized opportunities. As technology advances, we remain well positioned as these prospects come to realization over time.

We are fortunate to possess size, quality and diversity of opportunity within our existing asset base. Harvest has created a sustainable foundation for success.

SELECTED ANNUAL INFORMATION

The table below provides a summary of our financial and operating results for the years ended December 31, 2008, 2007 and 2006.

($000s except where noted)	Year ended December 31 2008	2007	2006
Revenue, net[1]	**5,489,364**	4,069,600	1,380,825
Cash from operating activities	**655,887**	641,313	507,885
Per Trust Unit, basic	**$ 4.29**	$ 4.63	$ 5.00
Per Trust Unit, diluted	**$ 4.05**	$ 4.30	$ 4.84
Net income (loss)[2]	**212,019**	(25,676)	136,046
Per Trust Unit, basic	**$ 1.39**	$ (0.19)	$ 1.34
Per Trust Unit, diluted	**$ 1.39**	$ (0.19)	$ 1.33
Distributions declared	**551,325**	610,280	468,787
Distributions declared, per Trust Unit	**$ 3.60**	$ 4.40	$ 4.53
Distributions declared as a percentage of cash from operating activities	**84%**	95%	92%
Bank debt	**1,226,228**	1,279,501	1,595,663
7⅞% Senior notes	**298,210**	241,148	291,350
Convertible debentures[3]	**827,759**	651,768	601,511
Total long-term financial debt[3]	**2,352,197**	2,172,417	2,488,524
Total assets	**5,745,407**	5,451,683	5,745,558
UPSTREAM OPERATIONS			
Daily production			
Light to medium oil (bbl/d)	**25,093**	27,165	27,482
Heavy oil (bbl/d)	**12,162**	14,469	13,904
Natural gas liquids (bbl/d)	**2,624**	2,412	2,247
Natural gas (mcf/d)	**96,315**	97,744	96,578
Total daily sales volumes (boe/d)	**55,932**	60,336	59,729
Operating netback ($/boe)	**47.89**	29.89	30.54
Cash capital expenditures	**271,312**	300,674	376,881
Business and property acquisitions, net	**128,773**	138,156	2,467,097
DOWNSTREAM OPERATIONS [4]			
Average daily throughput (bbl/d)	**103,497**	98,617	86,890
Average refining margin (US$/bbl)	**7.16**	10.05	9.32
Cash capital expenditures	**56,162**	44,111	21,411

(1) Revenues are net of royalties.

(2) Net income (loss) includes a future income tax expense of $108.6 million (2007 – an expense of $65.8 million; 2006 – a recovery of $2.3 million) and an unrealized net gain from risk management activities of $185.9 million (2007 - net losses of $147.8 million; 2006 – net gains of $52.2 million) for the year ended December 31, 2008. Please see notes 18 and 20 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

(4) Downstream operations acquired on October 19, 2006.

MESSAGE TO UNITHOLDERS

John Zahary
President & Chief Executive Officer

John Zahary is a professional engineer with extensive senior management experience in the oil and natural gas industry. Mr. Zahary holds a B.Sc. in Mechanical Engineering from the University of Calgary and a M.Phil. in Management from the University of Oxford.

The strength of our asset base, the skill of our employees and the flexibility of our business plan allowed Harvest Energy to achieve measured success in 2008 despite disparate market conditions.

Last year's rollercoaster of economic environments was like nothing the energy industry had ever seen. In the first half of 2008, record high crude oil and natural gas prices resulted in large cashflow increases from our exploration and production (upstream) business. That same economic environment challenged our refining and marketing (downstream) business as prices for refined products such as distillates, gasoline and heavy fuel oil did not rise as rapidly as crude oil.

In the second half of the year, we saw a significant and rapid reduction in commodity prices. Fortunately for Harvest, a reduction in the value of the Canadian dollar and an expansion in margins in the downstream business offset some of the reduction in cashflow from the upstream business. We also saw global financial markets come under stress. We recognize the importance of adapting to this new operating environment in 2009 and beyond.

Ultimately, our assets and employees will be key to our success as the markets change and provide new challenges and opportunities. Throughout 2008 and into 2009, we remain focused on value creation within our asset base and the pursuit of our Sustainable Growth strategy.

One of our greatest strengths is the quality of our assets. We focus on assets that have good cashflow characteristics and the opportunity for enhancement through improved operational practices and cost-effective but sophisticated development. We are fortunate to have an asset base that contains valuable upside both in our upstream and downstream businesses. We demonstrated that upside with our successful operational activities in 2008.

Despite volatile economic conditions, it is our commitment to capture the value of our assets through a disciplined approach that will ensure our success. Since Harvest was formed in 2002, our goal remains the same: to provide attractive returns to our investors through cost-effective management of low-risk energy investments. By capitalizing on our technical expertise, "Despite volatile economic conditions, it is our commitment to capture the value of our assets through a disciplined approach that will ensure our success."

Harvest is able to provide optimized cashflow with controlled costs in the short-term and focus on developing the unrealized value in our assets over the medium and longer-term. We have a dedicated team that carries this philosophy into the operation of our assets.

We appreciate the support of our unitholders and it is our pleasure to use this annual report to discuss the successes and challenges of 2008 along with our outlook for 2009.

UPSTREAM SEGMENT

The operational performance of Harvest's upstream business in 2008 was exemplary in a number of areas. Our performance is highlighted by our gas exploration and development success in west central Alberta, ongoing technology-driven horizontal well development in southeastern Saskatchewan and the successful implementation of enhanced recovery in the world class oil pool at Hay River in northeastern British Columbia.

Although natural gas production accounts for only 30% of our overall upstream business, this component has provided us with some of our greatest successes in finding and developing new accumulations of hydrocarbons. Through a series of land acquisitions over the past few years, we have built an impressive portfolio of development opportunities in west central Alberta. We realized the value of this portfolio in early 2008 when we tied in some of our drilling successes. Chedderville 3-13 has now been producing approximately 3.5 million standard cubic feet of natural gas per day plus 130 barrels per day (bbl/d) of natural gas liquids since early 2008. We followed up with three additional successful wells that were tied in late in 2008 and early 2009. While it is just four wells, their high productivity combined with additional development opportunities indicates a bright future for this sort of activity in the months and years ahead. It also illustrates our ability to open up new growth areas in our portfolio.

In southeastern Saskatchewan, we continued with our development activity in 2008. Over the year, we drilled 43 new horizontal wells in this region, increasing our total in southeastern Saskatchewan to over 150 horizontal wells since October 2003. Our approach in this area has been to utilize best-in-class horizontal drilling and development techniques to open up deposits of high quality light oil. We've managed to maintain production levels while only reinvesting a fraction of our cashflow from the region. While others have followed us to this area, we have led the way with our ongoing development.

Early in 2008 at Hay River we increased the water injection into our large 200 million barrel oilfield by about 20%. The impact of this increased water injection and well optimization increased production from 3,000 bbl/d in December 2007 to 4,000 bbl/d in April 2008 to 5,200 bbl/d in November 2008. This level of production was approximately 1,600 bbl/d better than we were expecting. This is an

impressive accomplishment given that it was achieved without any new oil well drilling. This indicates the opportunity for enhanced recovery in our oilfields. We followed up the waterflood enhancement at Hay River with a similar project at the Lark field in Suffield in mid 2008 and at Bellshill Lake in late 2008. We also advanced a polymer enhancement to our successful waterflood at Wainwright through 2008. We are excited by the potential of these fields and expect to continue implementing enhanced recovery. These projects make great economic sense even in times of lower oil prices because they can be implemented with relatively low capital costs.

While those were only a few of the highlights of our upstream program, they demonstrate the type of opportunity inherent in our asset base and the technologically advanced capability of our organization to enhance the performance of our assets. Our focus remains on our upstream oil and gas assets and our Sustainable Growth strategy where we continuously strive to enhance recovery of our reserves in order to maximize the value of our assets.

We remain well positioned for continued success. In the short term, we see ongoing attractive development opportunity even at lower than expected commodity prices of our horizontal drilling at Hay River and southeastern Saskatchewan as well as our liquids-rich natural gas opportunities in west central Alberta. We have a number of major oil pools where we see enhanced recovery through waterflooding, polymer flooding or intensive techniques such as carbon dioxide flooding and sequestration. We are also well positioned with coal bed methane, heavy oil and oil sands opportunities. We expect these unconventional assets to come to fruition over time as technology advances and commodity prices recover.

DOWNSTREAM SEGMENT

The second component of our asset base is our downstream refining and marketing segment in Newfoundland and Labrador. The downstream business provides vertical integration for our crude oil upstream business and a natural hedge for our crude quality discounts. It also provides extremely long-life assets and diversification of our cashflow that enhances our long-term sustainability.

In the downstream business, we are exposed to the margins between the price of the refined products we sell and the price of feedstocks we purchase and process. In 2008, refining margins in the first half of the year were compressed as refiners were unable to increase finished product prices at the same pace as the unprecedented increase in feed stock prices. In the second half of 2008, we saw much better margins in the downstream business. We also saw the benefit of our hydrocracking refinery configuration, which produces a high proportion of distillate products. Most other refineries in North America are configured to maximize gasoline production. In the later part of 2008, the soft economic conditions in North America led to a decrease in gasoline consumption and weaker margins for this product. The demand and margins for distillate products, such as diesel and jet fuel, were not as affected, so our heavier weighting of production to these products allowed us to capture stronger margins.

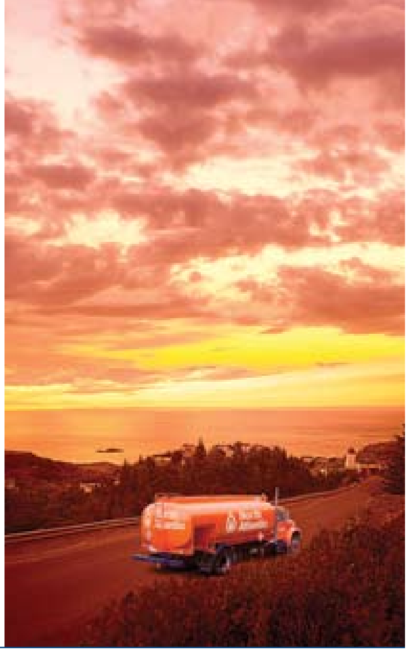
Operationally, the refinery's performance throughout the year was outstanding as equipment reliabilities and the absence of a turnaround in 2008 resulted in improved utilization of all major processing units compared to 2007. We strategically processed a different feedstock mix, varied unit operating rates and optimized operating parameters to minimize the production of gasoline and heavy fuel oil products and to maximize distillate product production. This helped offset the impact of changing market conditions. In 2008, we also reduced fixed operating expenses to below 2007 levels.

We took a number of steps in 2008 that contributed to improved performance from the refinery business. We shifted our heavy fuel oil sales to a major distributor, enhancing margins for this product. We maximized our production of distillate product through crude selection and operational practices and directed a high proportion of our distillate sales to the stronger European markets. We have quick and efficient access to Europe from our refinery on the northeastern edge of North America.

In November 2008, we successfully completed our visbreaker expansion project. The visbreaker is a processing unit that effectively reduces the necessity to blend higher valued distillate products into low valued heavy fuel oil products, and in 2009 we expect to realize a full year of improved margins from the recovery of about 1,500 bbl/d of distillate products previously blended into heavy fuel oil. We will also increase the capacity of our hydrocracker in 2009 during a planned shutdown of this unit for catalyst replacement.

In 2008, we also completed a detailed study of the technical and economic feasibility of capturing more broadly the significant profit improvement potential inherent in the refinery. From this effort, we have identified a suite of projects geared toward the integrated expansion and enhancement of several existing process units. This estimated three year, $300 million project has compelling economics, as it involves both low cost and simple debottlenecking of existing process units to capture additional capacities, enhanced yields and reduced expenses. The 2008 engineering study also identified a large-scale project to expand and reconfigure the refinery for significant margin improvement. With a timeline of five years and an estimated capital investment of $2 billion, this project would result in the expansion of crude oil capacity from 115,000 to 190,000 bbl/d, the conversion of the refinery to process lower cost heavy sour crude oils and the upgrading of low valued heavy fuel oil products into high valued distillate products. We believe this reconfiguration project is more economically compelling and attractive than similar projects under consideration by other refiners. These projects are optional to Harvest as we already have one of the highest reliabilities of refineries and produce some of the highest quality products available in the world today. We will advance this opportunity when the economic environment and financial conditions permit.

“Harvest is a recognized leader in business and operations activities. We have consistently maintained a disciplined approach in environment, health and safety issues and remain committed to operating in a socially responsible manner.”



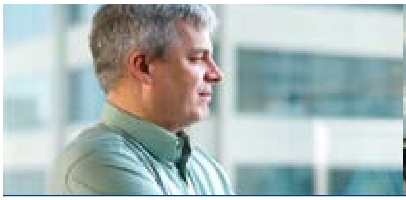
ENVIRONMENT, HEALTH & SAFETY

Harvest is a recognized leader in business and operations activities. We have consistently maintained a disciplined approach in environment, health and safety issues and remain committed to operating in a socially responsible manner. Protecting our people, our partners, our stakeholders and the environment are key elements of our business. We are active throughout the organization and we never forget that safe and environmentally friendly business practices are critical to our social licence to operate.

In our upstream segment, we are a participant in the Canadian Association of Petroleum Producers' Stewardship program. We are one of few companies that have shown the commitment for many years to report at the highest reporting level. In the downstream segment, we have set new internal safety records for time worked without lost time accidents, achieved industry leading recordable injury frequency rates and have been recognized for this and other achievements by regulatory authorities.

Harvest continues efforts to reduce greenhouse gas and other emissions in all parts of our business. Our business units conduct emergency response training on a regular basis in all of our operating fields to ensure a high level of response capability when placed in challenging situations. We also perform safety and environmental audits of our operating facilities. We work diligently to manage our liabilities through the controlled abandonment and reclamation of facilities, wells and leases. Harvest has consistently supported the communities we operate in by sponsoring and donating to local initiatives.

In all aspects of our business, we are committed to minimizing our environmental footprint, being a good and responsible corporate citizen and conducting our affairs in an environmentally and socially responsible manner.



OUTLOOK

Without a doubt, 2009 will not be without its challenges. An uncertain direction for commodity prices will make for tough decision-making in the year ahead. We've been afforded some relief by the reduction in the Canadian dollar, hedges that protect our cashflow in the upstream business through the first half of 2009, and the diversification of our cashflow streams between the upstream and downstream. This provides increased stability and sustainability. At all times, we need to be mindful of the opportunities inherent in our assets. Considering the state of credit markets, we need to continue to advance those opportunities in a prudent fashion in 2010 and 2011 as we also focus on improving financial flexibility by reducing debt levels.

We are fortunate to have high quality assets with tremendous upside potential. Although the economic environment could be better, we are extremely well positioned. We will maintain our operational principles and fundamental strategies in our upstream and downstream businesses while maintaining the flexibility to evolve during times of volatile commodity markets.

Sincerely,

John Zahary

President & Chief Executive Officer

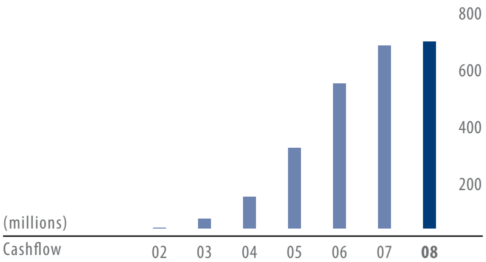
March 31, 2009

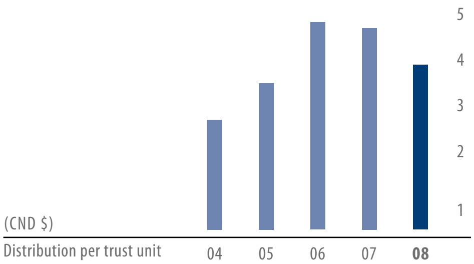
FINANCIAL OVERVIEW



2008 HIGHLIGHTS

- Cash from operating activities totalled $655.9 million
- Upstream operations contributed $945.9 million of cash from average daily production of 55,932 boe/d
- Acquisition of 2,650 boe/d of producing assets increased upstream production
- Capital spending of $271.3 million and $128.8 million of net acquisitions replaced 2008 production in upstream operations
- Downstream operations contributed $83.6 million of cash
- Downstream capital expenditures were $56.2 million, including commissioning of visbreaker expansion project
- Balance sheet liquidity was increased with the issuance of $250 million principal amount of 7.5% convertible unsecured subordinated debentures
- 2008 distributions totalled $551.3 million, $3.60 per Trust Unit, reflecting an 84% payout ratio based on cash from operating activities





Robert Fotheringham

Chief Financial Officer

Robert (Bob) Fotheringham brings to the organization more than 20 years of progressive experience in the energy industry and public accounting. He is a Chartered Accountant and holds an honours degree in Business Administration from the University of Western Ontario.

CASHFLOW

Our earnings and cashflow from operating activities are largely determined by the realized prices for our crude oil and natural gas production as well as refined product margins, including the effects of changes in the US dollar to Canadian dollar exchange rate. Recently, changes in crude oil and natural gas prices and the exchange rate between US dollars and Canadian dollars have moved together with changes in the currency exchange rate partially offsetting changes in crude oil and natural gas prices.

During 2008, cash from operating activities totalled $655.9 million, a $14.6 million increase as compared to $641.3 million in the prior year. While cash generated from our upstream operations of $945.9 million in 2008 was a significant increase from the $624.3 million in the prior year, the cash generated in our downstream operations of $83.6 million was approximately half the $165.0 million generated in the prior year. The $321.6 million improvement in our upstream operations reflects the year-over-year strength in commodity prices as well as a tightening of heavy crude oil differentials in western Canada. The reduced contribution from our downstream operations should be considered in light of the generally weaker refined product margins in 2008 as well as the impact of significantly lower commodity prices in the fourth quarter, resulting in inventory write-downs of $35.3 million. The average exchange rate between the Canadian dollar and US dollar was relatively unchanged year-over-year with the 2008 year-end exchange rate of CDN$1.00 to US$0.80, reflecting a significant strengthening of the US dollar in the last half of 2008. The increase in the US dollar bolstered our realized crude oil prices and refined product margins, both of which are denominated in US dollars.

UPSTREAM RESULTS

Our upstream operations averaged production of 55,932 boe/d in 2008 as compared to 60,336 boe/d in the prior year, a 7% reduction. Our production in 2008 reflects a modest 4% decline as compared to the 58,416 boe/d averaged in the fourth quarter of 2007 as our reduced capital program in 2008 and net acquisitions substantially stabilized our production. In 2007, we benefited from a $148.5 million drilling effort in the first quarter, boosting production to an average of 62,024 boe/d for the quarter as compared to capital expenditures of $79.6 million in the first quarter of 2008. In 2008, we shifted our efforts to the re-pressurization of a few of our larger oil reservoirs rather than further development drilling. As a result, we expect more stable benefits longer term, as compared to the flush production and accelerated declines associated with some drilling programs. Our operating costs of $300.9 million in 2008 are unchanged from the prior year as the overheated Alberta oilfield services industry did not weaken until late in the year with continued weakening expected in 2009. Our operating netback of $47.89 per boe represents a 60% increase over the prior year and is primarily attributed to higher commodity prices and tightening heavy crude oil differentials in western Canada.

During the third quarter of 2008, we completed two acquisitions for an aggregate cash consideration of $167.6 million. We acquired approximately 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas, representing an acquisition cost of approximately $63,000 per flowing boe. The principal asset acquired was a large pool of medium gravity oil, of which approximately 7% of the original oil in place has been recovered. It is anticipated that with a combination of additional drilling and reservoir management, the recoveries from this pool can be substantially improved. In addition to numerous minor acquisitions / dispositions, we disposed of 481 boe/d of natural gas and natural gas liquids production for $36.8 million, representing proceeds of approximately $76,000 per flowing boe.

DOWNSTREAM RESULTS

During 2008, our downstream operations generated $83.6 million of cash as compared to $165.0 million in the prior year. The reduced contribution was primarily the result of an $86.8 million drop in gross margin. The drop in North American demand for gasoline that began in mid-2007 continued through 2008 with the slowing US economy and record high prices curtailing consumer driving. As a result, the gasoline crack spread weakened significantly from the US$28.76 averaged during the second quarter of 2007 culminating in a negative spread during the fourth quarter of 2008. Similarly, the prices for high sulphur fuel oil (HSFO) during the first half of 2008 did not proportionately reflect increases in crude oil prices resulting in a significant deterioration of the HSFO crack spread which averaged US$38.75 less than the West Texas Intermediate (WTI) benchmark price of US$123.98/bbl during the second quarter of 2008 as compared to an average of US$26.52/bbl less than the WTI benchmark for the entire year. In contrast, the strong global demand for distillate products improved the refining margins for heating oil, diesel and jet fuel. Overall, our refining margin in 2008 was US$7.16 per barrel of throughput, a drop of $2.89 per barrel from the prior year.

Our refinery throughput averaged 103,497 bbls/d during 2008 with first quarter throughput of approximately 112,000 bbls/d somewhat tempered by a four day unplanned outage. Throughput from May through August was reduced to approximately 95,500 bbls/d to optimize margins by minimizing the production of HSFO and reduced to approximately 102,800 bbls/d from September through December due to fouling of heat exchangers. Average daily throughput in 2008 represents a utilization factor of 90% as compared to the refinery's 115,000 bbls/d nameplate capacity. As compared to the prior year with $34.5 million of turnaround and catalyst costs incurred during an extensive shutdown in the fourth quarter, our refinery operations incurred $5.6 million of turnaround and catalyst costs during a partial turnaround of the visbreaker unit in 2008. Our refinery operating costs totalled $78.9 million ($2.08 per bbl of throughput) in 2008 as compared to $83.9 million ($2.33 per bbl of throughput) in the prior year while our cost of purchased energy was $131.9 million ($3.48 per bbl) in the current year as compared to $92.3 million ($2.57 per bbl) in 2007 which when aggregated totals $5.56 per barrel of throughput for 2008 as compared to $4.90 in the prior year, a net increase of $0.66 per barrel.

FINANCING

In April 2008, we raised $239.5 million of net proceeds with the issuance of $250 million principal amount of 7.5% convertible unsecured subordinated debentures and applied the net proceeds to reduce borrowings under our extendible revolving credit facility. As the disruptions in the capital markets continued in 2008, we have deferred our request to extend the maturity date of our credit facility beyond April 2010 in an effort to maintain the cost of our bank borrowing as well as retain our $1.6 billion of credit capacity.

DISTRIBUTIONS

In 2008, we declared distributions to unitholders totalling $551.3 million ($3.60 per Trust Unit) as compared to $610.3 million ($4.40 per Trust Unit) in 2007. We have maintained a monthly distribution of $0.30 per Trust Unit since November 2007 and in light of the significant reduction in commodity prices, we declared a distribution of $0.05 per Trust Unit for unitholders of record on March 23, 2009 and payable on April 15, 2009. In the near term, substantially all of our cashflow from operating activities will be directed to enhancing unitholder value through capital expenditures focused on maintaining our productive capacity as well as low risk profit / growth initiatives with the remaining cash directed towards improving our balance sheet liquidity by repaying bank borrowings.

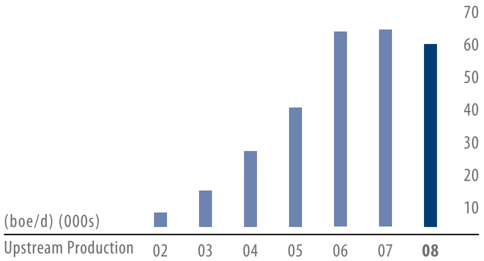
If you would like a copy of our audited consolidated financial statements for the year ended December 31, 2008 and/or our Management's Discussion and Analysis for the year ended December 31, 2008, please request one by emailing information@harvestenergy.ca and one will sent to you at no charge or you may review the documents filed on SEDAR at www.sedar.com.

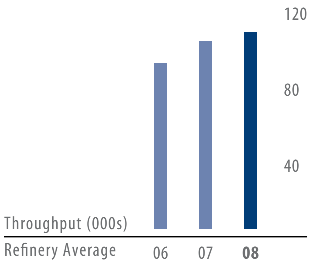
OPERATIONS OVERVIEW

OPERATIONAL HIGHLIGHTS

Current commodity prices have seen capital spending been deferred on some projects. Upstream capital spending has been revised to $170 million for 2009 delivering expected production of 50,000 boe/d. Downstream capital spending will be $50 million for 2009 with a focus on turnaround activities at the hydrocracker, while maintaining efforts on highly attractive small scale growth opportunities at the refinery.

Our diversity of cashflows will assist Harvest in this period of lower commodity prices. Early 2009 has seen an extremely strong contribution of cashflow from our downstream operations, which has partially mitigated the reduction in cashflow from the upstream segment. Strong margins for distillate products and fuel oil, along with improving margins for gasoline and a reduced Canadian dollar made January our strongest month for refining margins since we entered the downstream business. The outlook for the coming months remains positive.






TYLER

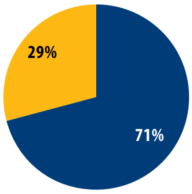
Rob Morgan

Chief Operating Officer, Upstream

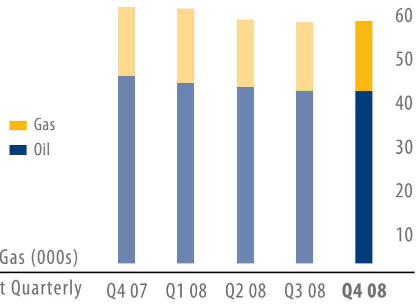
Rob Morgan is a professional engineer with 20 years of technical, operations and management experience in the oil and natural gas industry. He holds a Bachelor of Science degree in Chemical Engineering from the University of Saskatchewan.

OPERATION HIGHLIGHTS

- Operating cashflow of $945.9 million
- Average production of 55,932 boe/d characterized by stable quarter to quarter volumes
- Operating costs of $300.9 million, representing $14.70/boe
- Operating netback of $47.89/boe, representing an $18.00/boe (60%) increase over 2007
- Completion of two acquisitions for $167.6 million, to acquire 2,650 boe/d of production
- Capital spending of $271.3 million included the drilling of 247 wells (150.3 on a net basis) with a 100% success rate
- Reserve additions from our capital program and $128.8 million in net acquisitions, replaced 2008 production

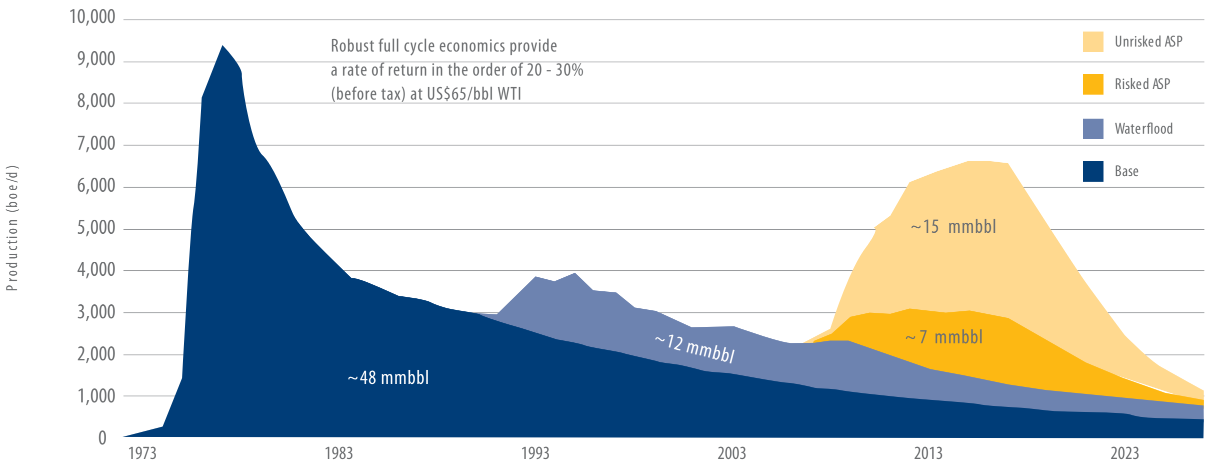


Oil/Gas
2008



Oil/Gas (000s)
Split Quarterly

EOR Report - Wainright, AB



Harvest's strategy has been to acquire upstream assets over time at attractive prices, identify and exploit short- and medium-term development opportunities and pursue long-term enhanced recovery of our extensive hydrocarbon resources.

Our approach and successes through 2008 speak for themselves as we were able to achieve a stable production profile throughout the year. The combination of a successful asset portfolio optimization program, exploration drilling program, development drilling program, production optimization and enhanced oil recovery implementation provide Harvest with an excellent base from which to deliver consistent production performance from quarter to quarter.

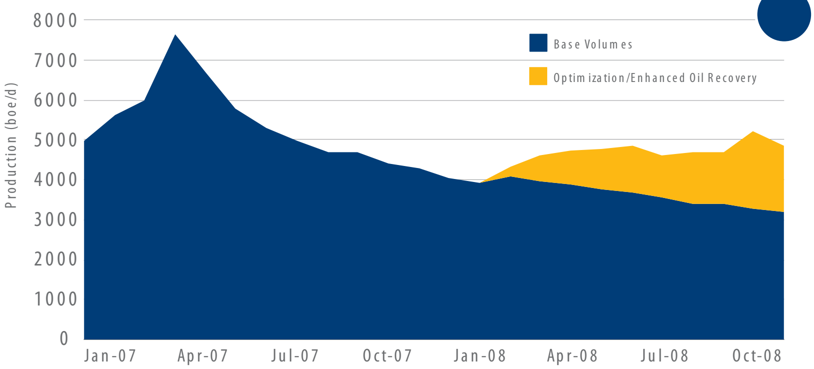
In 2008, we successfully completed $175 million of acquisitions and $46 million of asset dispositions. This compares with $202 million of acquisitions and $61 million of asset dispositions in 2007. Through this strategy we were able to monetize non-core assets, such as a minor, non-operated working interest in the Pouce Coupe area of northwest Alberta, and utilize the proceeds to partially offset acquisition costs for interests in Charlie Lake oil pools we acquired in the Cecil area of northern Alberta. The appeal of the Cecil assets is a large medium gravity (24 to 27° API) oil accumulation with a recovery factor to date of about 6% of the estimated 230 million barrels of gross original oil in place. As we have consistently demonstrated throughout our history, Harvest is able to apply the company's technical and operational expertise to this type of asset and achieve increased recovery factors leading to incremental value for unitholders.

The benefits of our focus on enhanced recovery became evident at our Hay River project during 2008. Hay River is a large medium-gravity crude oil accumulation in the Bluesky formation, which was acquired by Harvest in 2005. This winter-access-only area of northeast British Columbia had historically been the site of $50 to $100 million annual winter drilling programs to increase production, followed by eight to nine months of production decline. From our technical analysis of the pool, it became evident that the quantity of water injected to maintain the reservoir pressure was insufficient, and we chose not to drill any new wells in favour of reservoir optimization. With a capital budget of less than $5 million, we not only were able to arrest the decline, we were able to achieve increased production without drilling a single new producing well. With what we have accomplished through 2008, the reservoir is now well-positioned to capture the full benefit of our infill and step-out drilling programs in the years to come.

We completed two other enhanced water injection projects through 2008, including incremental water injection into our Bellshill Lake and Lark (Suffield) pools. These projects cost approximately $3 million each with the potential to similarly improve the base production level, provide pressure support for additional drilling and ultimately improve our recovery from these large original-oil-in-place fields. At Wainwright, we completed the construction of our polymer injection facility and expect to be initiating our polymer flood pilot project in early 2009. This is the first step towards ultimately using alkaline surfactant polymer (ASP) injection to access an incremental seven to 21 million barrels of oil equivalent of medium gravity (22 to 24° API) crude in this pool as well as evaluating this technology for use in other pools in our portfolio.

Another highlight of 2008 was the continuing success of our exploration programs. Harvest has a long history of identifying and developing prospects on our large undeveloped land base of approximately 500,000 net acres, resulting in a significant component of our growth profile. Over the last three years, Harvest's production from our successful exploration and subsequent development programs has grown to approximately 4,000 boe/d and we expect continued growth through 2009.

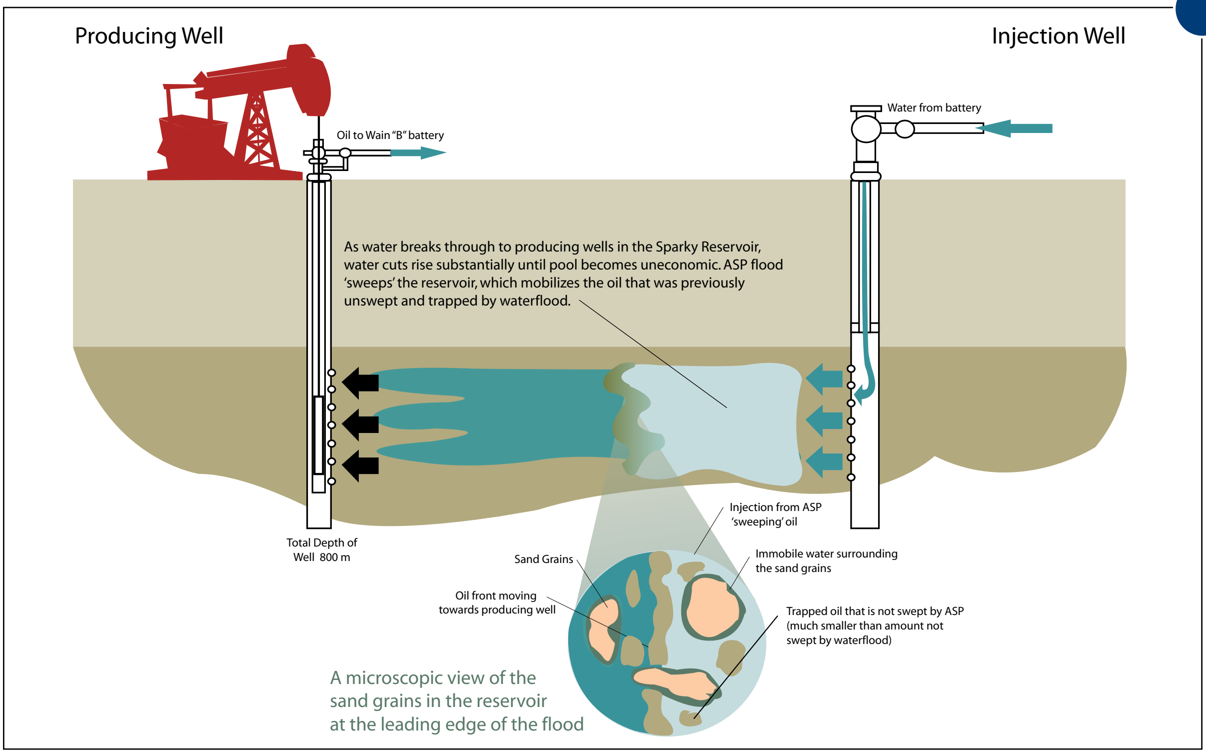
EOR Projects – Hay River B.C.

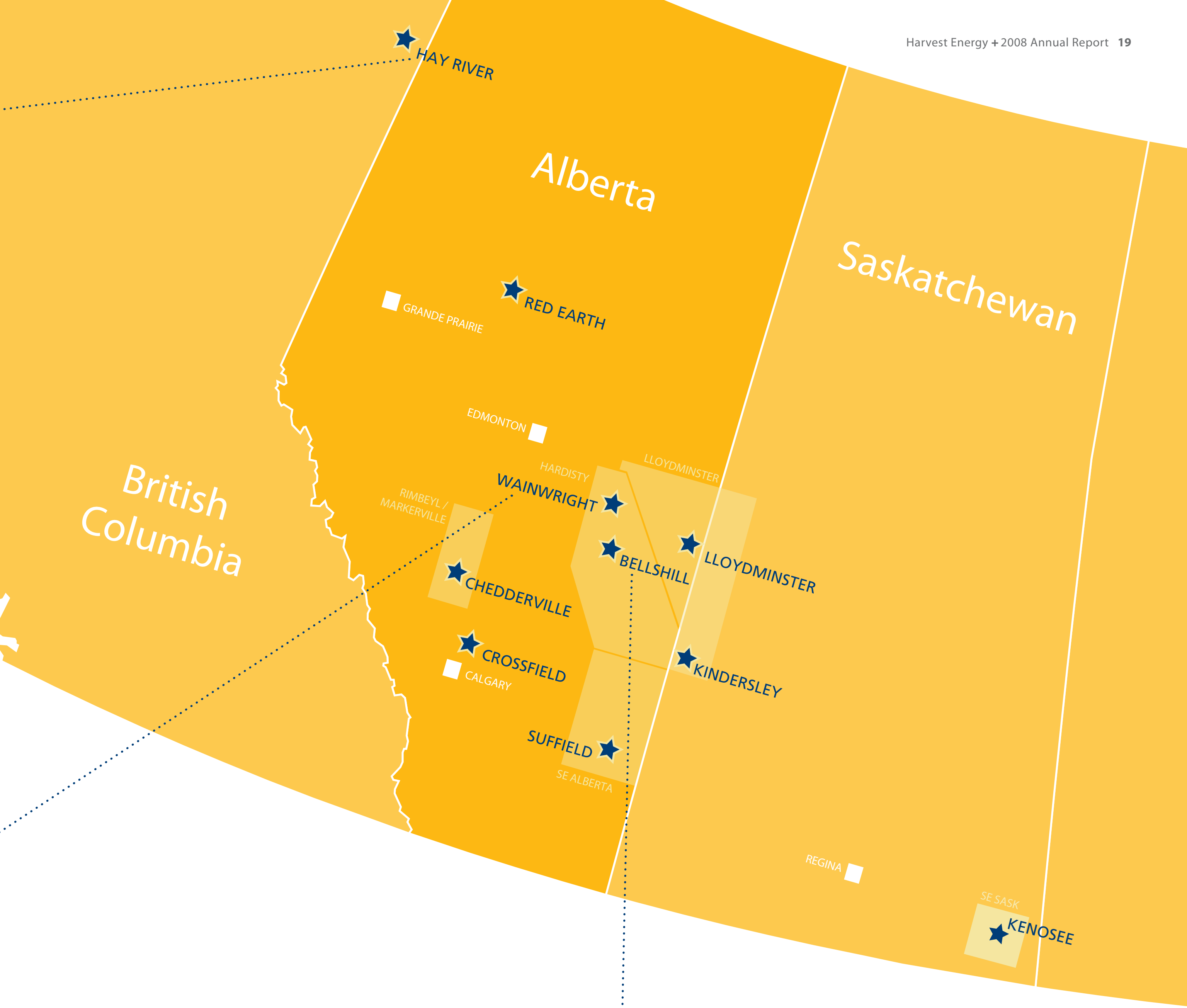


At Lloydminster, in eastern Alberta, our 2005 discovery of a heavy oil pool has led to 45 horizontal wells being drilled (18 in 2008). In early 2009, we successfully acquired a 50% working interest in a section of land adjacent to our Lloydminster acreage which will allow us to continue to develop this pool for the next two to three years. At Kenosee, in southeast Saskatchewan, a 2006 new pool discovery has resulted in over 25 horizontal wells being drilled (15 in 2008) to access light oil (33 to 35° API gravity). Further exploration in 2008 has identified an extension to this pool, increasing its original size by approximately 25%. At Chedderville, in west central Alberta, our 2007 Ostracod discovery well has led to three additional successful wells being drilled into the play during 2008, with an additional eight potential locations identified utilizing our proprietary 3D seismic data.

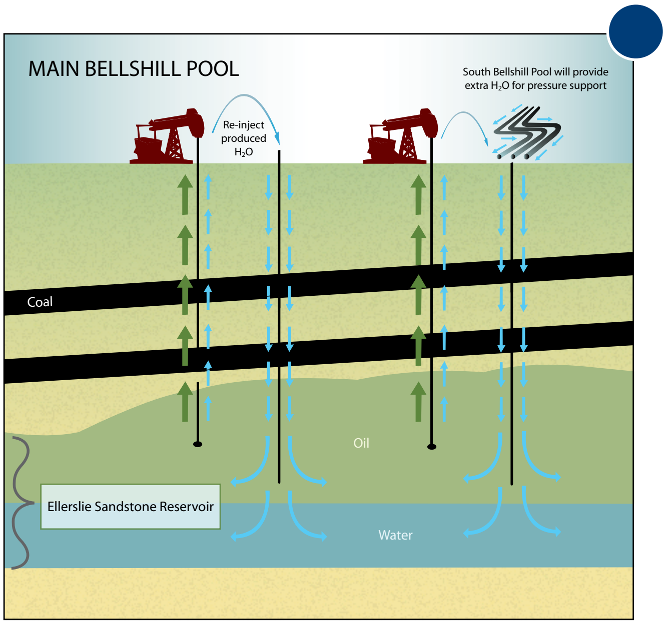
Technology continues to provide Harvest with other opportunities to access incremental hydrocarbons on our land base. At Red Earth, in northern Alberta, we drilled not only our first horizontal well into the Slave Point formation, but also used multistage fracture stimulation technology to access portions of this reservoir that would not have been accessible using conventional technology. The well has been successfully on production for five months now and we are assessing our next phase of drilling, which could result in up to 10 delineation wells over the next two years.

Polymer Flooding

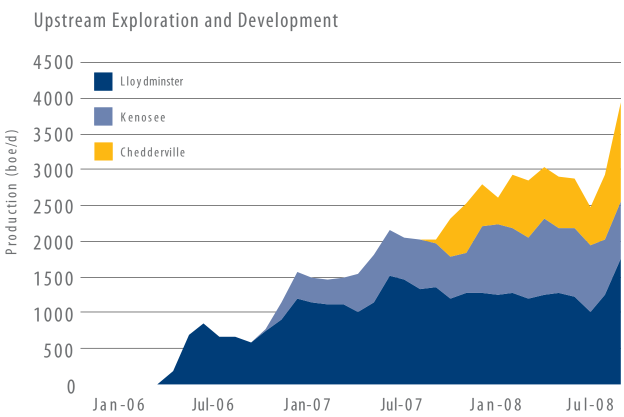




HAY RIVER
Alberta
Saskatchewan
British Columbia
RED EARTH
GRANDE PRAIRIE
EDMONTON
HARDISTY
LLOYDMINSTER
WAINWRIGHT
RIMBEYL / MARKERVILLE
BELLSHILL
LLOYDMINSTER
CHEDDERVILLE
CROSSFIELD
CALGARY
KINDERSLEY
SUFFIELD
SE ALBERTA
REGINA
SE SASK
KENOSEE



MAIN BELLSHILL POOL
South Bellshill Pool will provide extra H_2O for pressure support
Re-inject produced H_2O
Coal
Oil
Ellerslie Sandstone Reservoir
Water



Upstream Exploration and Development
Production (boe/d)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Lloydminster
Kenosee
Chedderville
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08

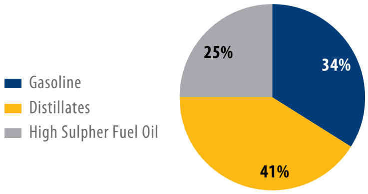
Brad Aldrich

Chief Operating Officer, Downstream

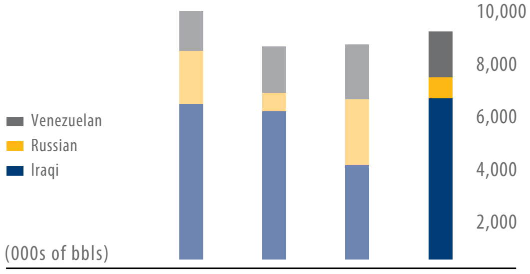
Brad Aldrich has over 27 years in the energy industry, with extensive management experience in petroleum refining and marketing, supply and trading, transportation and distribution, and major project investment. He received his Bachelor of Science degree in Industrial Engineering from New Mexico State University.

REFINERY HIGHLIGHTS

- Optimally configured to process medium sour crude oil
- 100% of the gasoline and ultra low sulphur diesel (ULSD) meets or exceeds current and anticipated future environmental specifications
- Production weighted towards high quality distillates rather than gasoline
- Located along Atlantic feedstock and product shipping routes
- Close proximity to high netback markets in New York, Boston and Europe
- Ice-free, deep water port enables VLCCs to dock – reduces cost, reduces risk of spillage
- One of the newest refineries in North America



Refined Product Split
2008

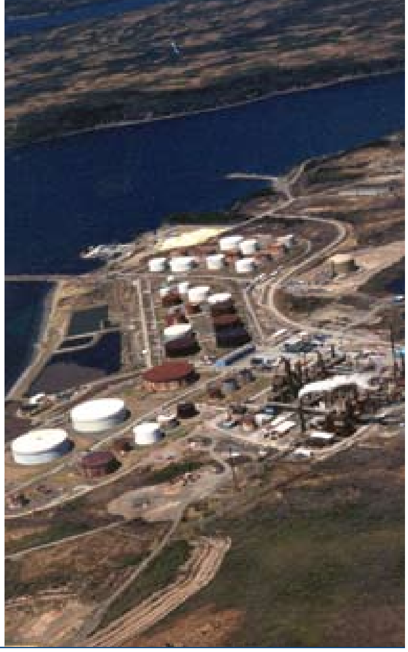


Refinery Feedstock

North Atlantic


3000 mi
2500 mi
2000 mi
1500 mi
1000 mi
500 mi
Calgary
North Atlantic
London
Amsterdam
Rotterdam
Genoa
Lavera
Bilbao
Gaeta
Sines
Boston
New York
San Francisco
Los Angeles
Jacksonville
Las Palmas
Teneriffe
San Vicente (Chile)

“The downstream business provides vertical integration for our crude oil upstream business and a natural hedge for our crude quality discounts.”



NORTH ATLANTIC REFINING

Complementing our upstream oil and gas assets in western Canada is our long-life downstream refining and marketing business in Newfoundland and Labrador. This business includes a modern fuels refinery, a network of 64 branded retail gasoline stations, a branded home heat division with 20,000 customers, a wholesale marketing division and two marine services businesses.

The refinery is a 115,000 barrels per stream day (BPSD) medium sour hydrocracking facility, which typically processes Middle Eastern, Russian and Latin American crude oils ranging from 1% to 3% sulphur and 24° to 34° API. This refinery positions North Atlantic to benefit from wide sour crude oil quality discounts, which are expected to remain wide as incremental export crude oil supplies tend to be disproportionately medium sour, whereas much of the global refining complex is designed to process lighter and sweeter crude oils. The crude oils that we process are very similar in quality to the oils we produce in western Canada. The refinery effectively vertically integrates our upstream and downstream businesses which creates a natural hedge, integration and diversification in our business.

The refinery’s ice-free deep-water dock is one of the deepest in North America, and it allows North Atlantic to directly receive very large crude carrier (VLCC) vessels carrying approximately 2 million barrels of crude oil. This provides significant cost advantages over US East Coast and Gulf Coast refineries, which can only receive much smaller vessels directly. Coupled with the refinery’s proximity to major sources of crude oil supply and the major markets for refined petroleum products, the facility has significant transportation cost advantages over its competitors. Over 90% of the production from the refinery is exported, mainly into the US East Coast (PADD I) and European markets.

The refinery is one of a relatively small number of refineries in North America utilizing catalytic hydrocracking for vacuum gas oil (VGO) processing. As a hydrocracking refinery, the product mix is more heavily weighted towards high quality distillates than the typical North American fluidized catalytic cracking (FCC) refinery, which is designed to maximize gasoline product yields. This weighting towards distillates enables North Atlantic to capitalize on robust global demand growth (and resultant high margins) for distillate products. For example, in 2008 the price for ultra low sulphur diesel (ULSD) in the US East Coast was about US$23 barrel higher than the price for our export gasoline.

The facility is a “clean fuels” refinery with the processing capability to achieve sulphur levels less than eight parts per million on all gasoline and distillate products. Therefore, North Atlantic’s products can be sold into global markets with the most stringent environmental specifications. These capabilities particularly enhance the refinery’s distillate product values in the nearby European market, and in niche markets such as California (which has stringent California Air Resources Board diesel specifications). In 2008 approximately 60% of the refinery’s ULSD production was sold into European markets with margin improvement of approximately $8 million over the alternative of selling into the Northeast US.

The broader energy industry, including the refining business, is seasonal and cyclical and subject to margin variability. The unprecedented increase of crude oil prices in the first half of 2008 had the effect of compressing refining margins, particularly for gasoline and high sulphur fuel oil (HSFO), as product price increases were generally unable to keep pace. The cost of low sulphur fuel oil (LSFO), necessary as fuel for refinery process heaters, also increased sharply. Consequently, first and second quarter financial results were considerably weaker than anticipated. As commodity prices fell during the third quarter, refining margins improved as product price decreases lagged crude oil, sour crude oil discounts improved, and the cost of purchased low sulphur fuel oils decreased. By the fourth quarter we saw reduced margins for gasoline due to a reduction in demand for transportation fuels, however, margins for distillates and heavy fuel oil remained strong.

Operationally, we were pleased with refinery performance, as equipment reliabilities and capacity utilization for all major processing units improved from 2007. In an effort to further offset weak market conditions we managed 2008 fixed operating expenses to a level below 2007. To capitalize on market conditions we adjusted our feedstock mix, throughput levels and individual refining processes to maximize distillate production. 2008 also marked the first year of sales of our HSFO products directly to a large purchaser in the New York harbour market, thereby eliminating the middleman and enhancing margins approximately US$8 million. In November, we also successfully completed and commissioned the visbreaker expansion project, which increased capacity of this unit from 18,000 to 20,000 BPSD and improved conversions resulting in the upgrading of about 1,500 BPSD of low valued HSFO into high valued distillate products.

Overall, we are pleased with 2008. As we enter 2009, we have a stronger platform for value creation in the downstream business with an opportunity portfolio and focus on continuing improvements.

OPPORTUNITIES FOR INVESTMENT

Among the reasons Harvest acquired the North Atlantic business is the opportunity to improve the profitability of the refinery through high return capital improvements. Although the refinery has had significant safety and reliability investments over the years, no capital has been invested to grow or expand its capacity, so it remains today essentially at its original size and process configuration.

In 2008, we commissioned and completed a comprehensive study by an independent engineering firm of a broad range of investment opportunities within the refinery. Three general areas of investment opportunity were identified:

- Expansion of feedstock capacity – Since no growth capital has been invested in the refinery since its original construction, attractive opportunities exist to increase overall refinery throughput.
- Conversion to heavy sour feedstock – Modifying various processing and utility units in the refinery would enable us to purchase heavier and sourer crude oils, which are less expensive than the existing feedstocks, while maintaining the existing high valued gasoline and distillate product yields.
- Upgrading of high sulphur fuel oil into light products – The addition of a delayed coking process unit would allow us to upgrade all of the low valued HSFO into higher valued gasoline and distillate products.

Our engineering study identified two particularly attractive investment opportunities. The first would involve the expansion of crude oil capacity from 115,000 to 120,000 BPSD; expansion of hydrocracker capacity from 37,000 to 42,000 BPSD; improvement of the combustion technologies of existing process heaters; and various other associated process and utility unit enhancements. This suite of projects would be completed over a three-year period and is estimated to cost approximately US$300 million. The anticipated improvement in gross margin and operating expenses from these projects would provide very attractive investment returns. The second would involve the large-scale expansion and reconfiguration of the refinery, modifications to existing processing units, and the addition of new processing units. Beyond simply expanding the crude capacity to 190,000 BPSD, this approach would also allow the processing of low cost heavy sour crude oils and the upgrading of all low value HSFO products into high value gasoline and distillate products. This five-year project is estimated to cost approximately US$2 billion and also offers attractive investment returns. While attractive, this project will only be advanced when economic conditions and financial markets allow.

North Atlantic is situated on a significant land base of over 475 acres and has underutilized capacity at the dock and in terms of its infrastructure. This gives our refinery distinct advantages over competing greenfield, new-build refinery projects. North Atlantic is also a large employer, is well regarded in the province, and is supported by the surrounding communities, including maintaining cooperative working relationships with government and local regulatory bodies. These factors underpin the very attractive economics for expansion compared to a new build. Given the limited refining capacity in the northeast part of North America, there are numerous benefits to considering these investment opportunities.

RESERVES OVERVIEW



RESERVE HIGHLIGHTS

- Through successful drilling, optimization and acquisition activities, reserves remained essentially flat year over year, with year end reserves of 219.9 million barrels of oil equivalent ("mmboe")
- We replaced approximately 100% of our 2008 production on a proved basis through acquisition and positive additions from our capital program
- Development and exploration capital as well as enhanced oil recovery investments totaled $263.6 million and added 16.0 mmboe proved and 13.7 mmboe proved + probable (P+P) reserves after the conversion of booked undeveloped reserves
- Finding, development and acquisition ("FD&A") costs, before changes in FDC, are $20.60 per boe on a P+P reserve basis. Including FDC, the P+P FD&A costs are $28.84 per boe
- Proved developed reserves continue to represent a high percentage (approximately 87%) of total proved reserves. Total proved reserves represent approximately 70% of total P+P reserves
- Effectively maintained a reserve life index (RLI) of approximately 12 years (P+P) based on 2009 guidence of 50,000 boe/d
- The net present value (NPV) (before taxes, discounted at 10%) of Harvest's P+P reserves increased 6% to $3,893.8 million, while the NPV of total proved reserves increased 3% to $2,941.8 million

The information presented below summarizes certain information contained in Harvest's reserves report for the year ended December 31, 2008. Our reserves were evaluated in accordance with National Instrument 51-101 ("NI51-101") by the independent reserve evaluators McDaniel & Associates Consultants Ltd. ("McDaniel") who evaluated approximately 35% and GLJ Petroleum Consultants Ltd. ("GLJ") who evaluated approximately 65%. The information and tables listed below for Harvest constitute a combined summary of the two separate reserve reports. Reserves data presented below is net of abandonment costs. The complete reserves disclosure as required under NI51-101, will be contained in Harvest's 2008 Renewal Annual Information Form, filed on SEDAR on or before March 30, 2009 and available on our website.

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

Unless otherwise indicated, all reserves stated herein are gross reserves (before royalty burdens and without including royalty interests), based on forecast prices and costs, except where indicated.

Harvest Reserves Summary as at December 31, 2008 – Forecast Prices and Costs

Gross[(1)]

Reserves Category	Light & Medium Crude Oil[(5)] (mmbbl)	Heavy Crude Oil[(5)] (mmbbl)	Associated & Non-Associated Gas (bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[(3)] 2008 (mmboe)	Total Oil Equivalent[(3)] 2007 (mmboe)
Proved						
Developed Producing	57.1	33.0	192.3	6.1	128.2	131.5
Developed Non-Producing	1.0	3.1	13.8	0.3	6.8	6.9
Undeveloped	10.4	4.1	25.9	0.5	19.3	16.0
Total Proved	68.5	40.2	232.0	6.8	154.3	154.5
Probable	28.8	19.0	90.2	2.9	65.7	66.5
Total Proved Plus Probable[(4)]	97.3	59.2	322.1	9.7	219.9	220.9

Net[(2)]

Reserves Category	Light & Medium Crude Oil [(5)] (mmbbl)	Heavy Crude Oil[(5)] (mmbbl)	Associated & Non-Associated Gas (bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[(3)] 2008 (mmboe)	Total Oil Equivalent[(3)] 2007 (mmboe)
Proved						
Developed Producing	51.2	28.5	163.2	4.4	111.3	115.6
Developed Non-Producing	0.8	2.5	11.7	0.2	5.5	5.8
Undeveloped	8.8	3.3	20.6	0.3	15.8	13.3
Total Proved	60.8	34.2	195.4	4.9	132.6	134.7
Probable	25.1	15.4	73.0	2.0	54.7	57.6
Total Proved Plus Probable[(4)]	85.9	49.6	268.4	6.9	187.2	192.3

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

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

(3) 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.

(4) Columns may not add due to rounding.

(5) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light / medium oil reserves by the following amounts: PDP: 11.2 mmboe, Proved Undeveloped: 6.9 mmboe, Total Proved: 18.1 mmboe, Probable: 5.3 mmboe and P+P: 23.3 mmboe, and would increase the net heavy oil reserves and reduce the light / medium oil reserves by the following amounts: PDP: 9.8 mmboe, Proved Undeveloped: 5.8 mmboe, Total Proved: 15.6 mmboe, Probable: 4.7 mmboe, and P+P: 20.2 mmboe.

Through successful drilling, optimization and acquisition activities we replaced approximately 100% of our 2008 production on a proved basis. Development and exploration capital as well as enhanced oil recovery investments added 16.0 mmboe proved and 13.7 mmboe P+P. Our proved developed reserves continue to represent a high percentage (approximately 87%) of our total proved reserves, which represent approximately 70% of our total P+P reserves.

Based on our 2009 guidance of approximately 50,000 boe/d and our year end 2008 reserves, our P+P reserve life index (RLI) remains at approximately 12 years.

Harvest Net Present Value of Future Net Revenue of Reserves as at December 31, 2008 – Forecast Prices and Costs

Harvest's crude oil, natural gas and natural gas liquids reserves were evaluated using McDaniel's product price forecasts effective January 1, 2009 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. Note that this presentation is on a before tax basis, and when the tax measures announced on October 31st and passed into law in 2007 become enacted in 2011 then the after tax values could be different than the pre-tax number presented herein. It should not be assumed that estimates of the discounted future net production revenue represent the fair market value of Harvest's reserves.

Reserves Category	0% ($millions)	5% ($millions)	10% ($millions)	15% ($millions)	20% ($millions)
Proved					
Developed Producing	4,338.2	3,228.3	2,585.6	2,167.5	1,873.9
Developed Non-Producing	203.8	149.3	118.3	97.9	83.3
Undeveloped	510.0	340.5	238.4	172.2	126.6
Total Proved	5,052.1	3,718.1	2,942.3	2,437.6	2,083.9
Probable	2,655.0	1,466.2	951.9	680.1	516.3
Total Proved Plus Probable(1)	7,707.0	5,184.3	3,894.2	3,117.7	2,600.2

(1) Columns may not add due to rounding.

Net Asset Value		$ Millions
North Atlantic Refining Ltd. (1)	$	1,546
Reserves NPV10	$	3,894
Land / Seismic (2)	$	$125
Total Debt	$	(2,350)
Total NAV	$	3,215
Trust units outstanding at Dec. 31, 2008		157.2
NAV / Trust unit at Dec. 31, 2008	$	20.45

(1) Book value of the North Atlantic refinery as at December 31, 2008

(2) Land valuation of approximately $100/acre validated externally. Seismic value is an internal estimate.

McDaniel & Associates Consultants Ltd. – January 1, 2009 Price Forecast

A summary of the McDaniel price forecast as at January 1, 2009 that was used in the Harvest reserves evaluation is listed below. A complete listing of the price forecast is available on the McDaniel's website at www.mcdan.com/pricing_forecasts.html.

Year	WTI Crude Oil US$/bbl(1)	Edmonton Light Crude Oil C$/bbl(2)	Alberta Bow River Hardisty Crude Oil C$/bbl(3)	Alberta Heavy Crude Oil C$/bbl(4)	Alberta AECO Spot Price C$/GJ	US/CAN Exchange Rate US$/CAN$
2009	60.0	69.6	54.8	47.0	7.40	0.85
2010	71.4	83.0	65.3	56.1	8.00	0.85
2011	83.2	91.4	72.0	61.8	8.45	0.90
2012	90.2	93.9	73.9	64.0	8.80	0.95
2013	97.4	96.3	75.9	65.6	9.05	1.00
2014	99.4	98.3	77.4	67.0	9.25	1.00
2015	101.4	100.3	79.0	68.8	9.45	1.00
2016	130.4	102.3	80.5	70.2	9.60	1.00
2017	105.4	104.2	82.1	71.6	9.80	1.00
2018	107.6	106.4	83.8	73.0	10.00	1.00
2019	109.7	108.5	85.4	74.5	10.20	1.00
2020	111.9	110.7	87.2	76.0	10.40	1.00
2021	114.1	112.8	88.9	77.5	10.60	1.00
2022	116.4	115.1	90.7	79.0	10.80	1.00
2023	118.8	117.5	92.5	80.7	11.05	1.00
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	1.00

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

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

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

(4) Bow River at Hardisty Alberta (heavy stream)

Harvest 2008 Reconciliation Table – Forecast Prices and Costs

	Total Barrels of Oil Equivalent (boe)	
FACTORS	Gross Proved (mmboe)	Gross Proved Plus Probable (mmboe)
December 31, 2007	**154.5**	**220.9**
Technical revisions	6.7	0.6
Extensions / improved recovery	8.5	12.0
Discoveries	0.2	0.1
Economic / PV accretion	0.6	0.9
Acquisitions / divestitures	4.2	5.8
Production	(20.4)	(20.4)
December 31, 2008(1)	**154.3**	**219.9**

(1) Columns may not add due to rounding.

As indicated in the table above, our P+P reserve additions (excluding acquisitions / divestitures) totalled 13.7 mmboe.

Finding, Development and Acquisition Costs

In the interests of continuity and consistency, we have elected to present F&D and FD&A costs calculated both excluding and including FDC. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

		Total Proved		Proved Plus Probable
Development capital expenditures ($MM)	$	263.6	$	263.6
Change in future development capital (FDC) ($MM)	$	153.0	$	144.2
Total development capital ($MM)	$	416.6	$	407.8
Reserve additions (mmboe)		16.0		13.7
F&D costs ($/boe)	**$**	**25.97**	**$**	**29.87**
F&D costs before changes in FDC ($/boe)	**$**	**16.43**	**$**	**19.31**
Development and acquisition capital expenditures ($MM)	$	400.0	$	400.0
Change in future development capital (FDC) ($MM)	$	164.1	$	160.0
Total development & acquisition capital ($MM)	$	564.1	$	560.0
Reserve additions (mmboe)		20.2		19.4
FD&A costs ($/boe)	**$**	**27.90**	**$**	**28.84**
FD&A costs before changes in FDC ($/boe)	**$**	**19.78**	**$**	**20.60**
Three year average F&D ($/boe)	$	27.27	$	28.00
Before FDC ($/boe)	$	23.01	$	22.32
Three year average FD&A ($/boe)	$	28.78	$	25.47
Before FDC ($/boe)	$	25.04	$	20.94


TYLER

ENVIRONMENT, HEALTH & SAFETY

ENVIRONMENT, HEALTH & SAFETY (EH&S)

As an integrated oil company, we are focused on the full spectrum of environment, health and safety issues both in the upstream business and in the downstream business. Each segment has its unique challenges and opportunities, but our overriding principles of safe operations with minimal impact to the environment are consistent across our entire business. We use responsible practices to ensure the protection of people and the environment. Safety is at the core of our operations and is of utmost importance as we strive to protect our people, our neighbors and the environment we all share.

Stewardship of our EH&S programs is the responsibility of our Reserves, Safety and Environment Committee of the Board of Directors, who review our performance on a quarterly basis. This committee is supported by our corporate EH&S Management Committee, as well as our upstream and downstream teams of dedicated professionals who regularly monitor our performance to ensure Harvest conducts business in accordance with all regulatory requirements and industry best practices.

"Protecting our people, our partners, our stakeholders and the environment are key elements of our business."

UPSTREAM EH&S

In Western Canada, we maintain a proactive safety management program that defines key principles by which all work is to be conducted, and defines specific responsibilities for all levels of personnel in the upstream organization. All new employees and worksite supervisors are provided with safety orientation and training in identification, assessment and control of potential workplace hazards. We maintain comprehensive corporate and site specific emergency response plans, and test them regularly to ensure personnel are adequately trained to effectively handle emergencies and protect the public.

HIGHLIGHTS:

- Harvest continues to maintain its Platinum-level status in the Canadian Association of Petroleum Producers' (CAPP) Stewardship program. Harvest is committed to the Stewardship reporting framework, which focuses on continuous improvement and reporting of environmental, health, safety and social performance.

- In 2008, Harvest completed a 2006 Greenhouse Gas (GHG) emission baseline in which 62 facilities meet the threshold for mandated emission reduction requirements through the federal government's existing regulatory framework, positioning us to meet both the provincial and federal future targets for GHG reductions.

- In 2008, Harvest completed the installation of gas conservation projects in its Hay River and Lloydminster regions that are expected to significantly reduce both flaring and venting of gas in 2009. In Hay River there will be an estimated 60% reduction in flaring with an additional reduction expected by year end. In the Lloydminster region an estimated 60% of the vented gas was conserved in 2008.

- Harvest's fugitive emission detection and control plan will be fully implemented by the end of 2009 and is predicted to show positive economic results and significant GHG reductions.

- Harvest participated in the industry initiative Safety Stand Down in which senior executives visit frontline workers at their worksites to discuss safety issues. Approximately 26 field sites were visited and over 200 personnel attended the events, which provide a forum for safety discussion and feedback.

- In 2008 the Harvest Corporate Emergency Response plan was updated to meet the revised regulatory requirements set forth by the Energy Resources Conservation Board (ERCB). This update included the establishment of an emergency command centre and corporate emergency response team.

- With 55 well-site reclamations completed and submitted for certification in 2008 and over 200 ongoing reclamation projects, Harvest continues to demonstrate its commitment to sustainability and its belief that good environmental stewardship is a critical component of our day to day business.

DOWNSTREAM EH&S:

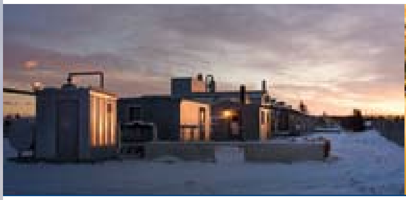
The North Atlantic refinery has an integrated management system which incorporates environment, health and safety considerations into day-to-day operations. The key components of this continuous improvement program include job safety analysis, incident investigations, risk management, detailed equipment inspections, work permitting, as well as maintaining in-house government-certified inspectors and Canadian Registered Safety Professionals. Refinery employees receive regular training in first aid, fire prevention / protection, oil spill response, and emergency response. We regularly perform stack sampling, soil, vegetation, and fresh and ocean water tests, and we have monitoring stations to record the air quality in three adjacent communities, as well as at the refinery perimeter.

North Atlantic externally reports environmental performance through periodic meetings and correspondence with the Community Liaison Committee ("CLC"), which is composed of representatives of the communities adjacent to the refinery, as well as provincial and federal government regulators.

HIGHLIGHTS

- October 26, 2008 marked the two year anniversary of Harvest's acquisition of North Atlantic and the achievement of record safety performance. In the first 24-months of Harvest's ownership, the downstream employees accumulated 2.6 million person-hours of occupational exposure and suffered only one lost-time accident ("LTA"). This represents an LTA frequency rate of 0.07 per 200,000 person-hours of exposure, which compares to an industry average of 0.40.
- For the calendar year 2008, North Atlantic refinery employees also achieved a total recordable accident frequency rate of 1.03 per 200,000 person-hours of exposure, which is a new North Atlantic record and compares to an industry average of 1.20.
- From an industrial hygiene standpoint, North Atlantic expanded its comprehensive employee monitoring, sampling and testing protocol to include Naturally Occurring Radioactive Material ("NORM") and benzene exposures.
- There were no regulatory compliance issues such as air or effluent water quality violations at North Atlantic in 2008.

CORPORATE GOVERNANCE



Harvest Energy is committed to maintaining effective corporate governance practices and appreciates that our reputation for transparency and integrity is significant to the success of our organization. At Harvest, we believe that our Board of Directors, officers and employees demonstrate the highest standards of professional and ethical conduct.

Harvest has adopted certain structures, policies and procedures, in addition to our Corporate Code of Business Conduct and Ethics, to ensure that effective corporate governance practices are followed. Our Board Mandate describes Harvest's approach to corporate governance, which reflects Harvest's historical commitment to effective corporate governance, as well as to the applicable regulatory requirements, guidelines established by the Canadian Securities Administrators under National Instrument 58-101, details of which are included in our 2008 Proxy Statement and Information Circular filed on SEDAR, EDGAR and posted on the Harvest website. We also comply with the relevant internal control and disclosure certification requirements of the US Sarbanes-Oxley Act, which ensures that we have processes and controls in place to promote sound business practices throughout the organization.

Harvest's Board consists of nine members, all of which are independent with the exception of John Zahary. Our Board is comprised of experienced individuals with integrity, core operational competencies, financial capabilities and the motivation needed to carry out their fiduciary duties in the best long term interests of the corporation and our unitholders. Our directors and officers collectively own approximately 4.5% of the trust units outstanding. As a result of their significant ownership stake, Harvest insiders are well aligned to effectively represent the interests of unitholders.

In 2008, Harvest welcomed William D. Robertson as a Board member and appointed Mr. Robertson Chairman of the Audit Committee. Mr. Robertson comes to Harvest highly qualified as a Fellow Chartered Accountant. He was formerly the lead oil and gas specialist at PriceWaterhouseCoopers in Calgary. He served on the CIM Petroleum Society Standing Committee on Reserve Definitions, the Financial Advisory Committee of the Alberta Securities Commission, the working sub committee of the Alberta Securities Commission on Oil and Gas Reporting and the Council of the Institute of Chartered Accountants of Alberta.

The Board has responsibility for the overall stewardship of Harvest, including but not limited to the corporate planning process, risk management policies and programs, management development and succession planning, significant business development (including large acquisitions and major financing proposals such as the issuance of trust units or debt structuring), and the integrity of internal control and information systems.

Three specific Board committees have been established to ensure maximum efficiency and effectiveness: the Audit Committee, the Corporate Governance and 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.

Audit Committee

Members: William Robertson (Chairman of the Committee), Hector McFadyen and Dale Blue

The Audit Committee is responsible for assessment all financial statements on a quarterly basis and making recommendations regarding approval to the full Board. In addition, it evaluates annual financial statements independently with Harvest's auditors, prior to presentation of such statements to the Board for approval. This committee examines the integrity of management's reporting systems, and with management and the Auditors' assistance, reviews management reporting, internal financial and operating controls, and policies and practices.

Corporate Governance Committee / Compensation Committees

Members: M. Bruce Chernoff (Chairman of the Committee), John Brussa and William Friley

The Corporate Governance / Compensation Committee provides assistance to the Board with its oversight responsibility with respect to human resources policies, compensation, succession planning and proposing new board nominees and assessing directors. The committee is also responsible to review and recommend to the Board management's succession plan including provisions for appointing, training and monitoring senior management, reviewing the effectiveness of the Board and its committees, and reviewing the appropriateness of the current and future organizational structure of the Trust.

Reserves, Safety & Environment (RSE) Committee

Members: David Boone (Chairman of the Committee), Verne Johnson and John Zahary

Harvest's RSE Committee has responsibility for the review of annual independent reserve engineering evaluation reports, including reviewing the qualifications, experience and independence of the independent reserve evaluators, and meeting with the individuals from those firms who prepare such reports. This committee also assists directors in meeting their responsibilities (particularly for accountability) with respect to Harvest's legal, industry and community obligations pertaining to the areas of health, safety and environment, as well as the establishment and implementation of appropriate environment, health and safety policies and procedures.

CORPORATE INFORMATION

DIRECTORS

M. Bruce Chernoff, Chairman (3)
Dale Blue (1)
David Boone (2)
John Brussa (3)
William Friley (3)
Verne Johnson (2)
Hector McFadyen (1)
William Robertson (1)
John Zahary (2)

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

OFFICERS & SENIOR MANAGEMENT

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

Robert Fotheringham, C.A.
Chief Financial Officer

Rob Morgan, P.Eng.
Chief Operating Officer, Upstream

Brad Aldrich
Chief Operating Officer, Downstream

Gary Boukall, P. Geol.
Vice President, Geosciences

Les Hogan
Vice President, Land

Phil Reist, C.A.
Vice President, Controller

Jim Sheasby, P.Eng.
Vice President, Engineering

Neil Sinclair
Vice President, Operations

Dean Beacon
Treasurer

David Rain, C.A.
Corporate Secretary

F. Steven Saunders, C.A.
Director of Taxation and Assistant Corporate Secretary

TRUST UNIT LISTING

Toronto Stock Exchange: HTE.UN
New York Stock Exchange: HTE

Convertible Debenture Listings:

TSX Ticker	Coupon	Conversion	Price Maturity
HTE.DB	9%	$13.85	May 31, 2009
HTE.DB.A	8%	$16.07	September 30, 2009
HTE.DB.B	6.5%	$31.00	December 31, 2010
HTE.DB.D	6.40%	$46.00	October 31, 2012
HTE.DB.E	7.25%	$32.20	September 30, 2013
HTE.DB.F	7.25%	$27.25	February 28, 2014
HTE.DB.G	7.50%	$27.40	May 31, 2015

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
310, 606-4th Street S.W.
Calgary, Alberta , Canada T2P 1T1
Telephone: (403) 233-2801

AUDITOR

KPMG LLP

LEGAL COUNSEL

Canada: Burnet, Duckworth & Palmer
U.S: Paul, Weiss, Rifkind, Wharton & Garrison

RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
McDaniel & Associates Ltd.

INVESTOR RELATIONS

Toll Free: 866-666-1178
Email: information@harvestenergy.ca

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

Designed by Bryan Mills Iradesso

Harvest ENERGY

2100, 330-5th Avenue S.W.
Calgary, Alberta,
Canada T2P 0L4

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Harvest ENERGY

Audited Consolidated Financial Statements and Management's Discussion and Analysis

for the year ended December 31, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2008 and 2007. The information and opinions concerning our future outlook are based on information available at March 2, 2009.

In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. All references are to Canadian dollars unless otherwise indicated. Tabular amounts are in thousands of dollars unless otherwise stated. Natural gas volumes are converted to barrels of oil equivalent ("boe") using the ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil ("bbl"). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, petroleum and natural gas revenues are reported on a gross basis before deduction of Crown and other royalties. In addition to disclosing reserves under the requirements of National Instrument 51-101, we also disclose our reserves on a company interest basis which is not a term defined under National Instrument 51-101. This information may not be comparable to similar measures by other issuers.

NON-GAAP MEASURES

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Cash G&A and Operating Netbacks are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans, while Operating Netbacks are always reported on a per boe basis, and include gross revenue, royalties, operating expenses, and transportation and marketing expenses. Gross Margin is also a non-GAAP measure and is commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations is also a non-GAAP measure and is commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the year ended December 31, 2008 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; risks associated with refining and marketing operations; the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

Forward-looking statements in this MD&A include, but are not limited to, the forward looking statements made in the "Outlook" section as well as statements made throughout with reference to production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, cash from operating activities, and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects", and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although we consider such information reasonable at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances, estimates or opinions change, except as required by law. Forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Consolidated Financial and Operating Highlights – 2008

- Cash from operating activities of $655.9 million, relatively unchanged from $641.3 million in the prior year, as a $321.6 million improvement in the contribution from upstream operations was substantially offset by a $174.5 million increase in the cash settlements on price risk management contracts, an $81.4 million drop in contribution from downstream operations and a $19.1 million realized loss on currency exchange transactions as compared to a gain of $53.6 million in the prior year.
- Upstream operations contributed $945.9 million of cash reflecting average daily production of 55,932 boe with strong commodity prices more than offsetting a strengthening Canadian dollar, lower production and higher operating costs.
- Upstream production was bolstered with the acquisition of 2,650 boe/d of producing assets in the Third Quarter for cash consideration of $167.6 million, representing a cost per flowing barrel of approximately $63,000.
- Capital spending of $271.3 million in our upstream business, plus $128.8 million of net acquisitions, replaced our 2008 production with finding and development costs, including changes in future development costs, of $25.97 per boe of proved reserves and $29.87 per boe for proved plus probable reserves.
- Downstream operations contributed $83.6 million of cash reflecting sound operating performance more than offset by generally lower refining margins as high commodity prices during the first three quarters increased our cost of purchased energy and lower commodity prices in the Fourth Quarter resulted in an inventory write-down.
- Capital expenditures in our downstream operations totaled $56.2 million, including the commissioning of our $30.1 million visbreaker expansion project in November, which is expected to upgrade approximately 1,500 bbls/d of high sulphur fuel oil ("HSFO") to distillate yield.
- Record high commodity prices resulted in $200.8 million of cash settlements on our price risk management contracts with $225.2 million of net cash settlements during the first three quarters offset by $24.4 million of settlements in our favour during the Fourth Quarter.
- Balance sheet liquidity was improved with the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures for net proceeds of $239.5 million in April 2008.
- Declared distributions totaling $551.3 million ($3.60 per Trust Unit) reflecting an 84% payout ratio based on cash from operating activities and 81% payout ratio if asset retirement expenditures and non-capital working capital are excluded from the cash flow.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the years ended December 31, 2008, 2007 and 2006.

	Year Ended December 31		
($000s except where noted)	**2008**	2007	2006
Revenue, net[1]	**5,489,364**	4,069,600	1,380,825
Cash From Operating Activities	**655,887**	641,313	507,885
Per Trust Unit, basic	**$ 4.29**	$ 4.63	$ 5.00
Per Trust Unit, diluted	**$ 4.05**	$ 4.30	$ 4.84
Net Income (Loss)[2]	**212,019**	(25,676)	136,046
Per Trust Unit, basic	**$ 1.39**	$ (0.19)	$ 1.34
Per Trust Unit, diluted	**$ 1.39**	$ (0.19)	$ 1.33
Distributions declared	**551,325**	610,280	468,787
Distributions declared, per Trust Unit	**$ 3.60**	$ 4.40	$ 4.53
Distributions declared as a percentage of Cash From Operating Activities	**84%**	95%	92%
Bank debt	**1,226,228**	1,279,501	1,595,663
7⅞% Senior Notes	**298,210**	241,148	291,350
Convertible Debentures[3]	**827,759**	651,768	601,511
Total long-term financial debt[3]	**2,352,197**	2,172,417	2,488,524
Total assets	**5,745,407**	5,451,683	5,745,558
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**25,093**	27,165	27,482
Heavy oil (bbl/d)	**12,162**	14,469	13,904
Natural gas liquids (bbl/d)	**2,624**	2,412	2,247
Natural gas (mcf/d)	**96,315**	97,744	96,578
Total daily sales volumes (boe/d)	**55,932**	60,336	59,729
Operating Netback ($/boe)	**47.89**	29.89	30.54
Cash capital expenditures	**271,312**	300,674	376,881
Business and property acquisitions, net	**128,773**	138,156	2,467,097
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**103,497**	98,617	86,890
Average Refining Margin (US$/bbl)	**7.16**	10.05	9.32
Cash capital expenditures	**56,162**	44,111	21,411

(1) Revenues are net of royalties.

(2) Net Income (Loss) includes a future income tax expense of $108.6 million (2007 – an expense of $65.8 million; 2006 – a recovery of $2.3 million) and an unrealized net gain from risk management activities of $185.9 million (2007 - net losses of $147.8 million; 2006 – net gains of $52.2 million) for the year ended December 31, 2008. Please see Notes 18 and 20 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

(4) Downstream operations acquired on October 19, 2006.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operation and further development of assets in western Canada (our "upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude oil hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador (our "downstream operations"). Our earnings and cash flow from operating activities are largely determined by the realized prices for our crude oil and natural gas production as well as refined product crack spreads, including the effects of changes in the U.S. dollar to Canadian dollar exchange rate. Recently, changes in crude oil and natural gas prices and the exchange rate between U.S. dollars and Canadian dollars have moved together with changes in the currency exchange rate partially offsetting changes in crude oil and natural gas prices.

During 2008, cash from operating activities totaled $655.9 million, a $14.6 million increase as compared to $641.3 million in the prior year. While cash generated from our upstream operations of $945.9 million in 2008 was a significant improvement from the $624.3 million in the prior year, the cash generated in our downstream operations of $83.6 million was approximately half the $165.0 million generated in the prior year. The $321.6 million improvement in our upstream operations reflects the year-over-year strength in commodity prices as well as a tightening of heavy crude oil differentials in western Canada. The reduced contribution from our downstream operations should be considered in light of the generally weaker refined product crack spreads in 2008 as well as the impact of significantly lower commodity prices in the Fourth Quarter resulting in inventory write-downs of $35.3 million. The average exchange rate between the Canadian dollar and U.S. dollar was relatively unchanged year-over-year with the 2008 year-end exchange rate of Cdn$1.00 to US$0.80 reflecting a significant strengthening of the U.S. dollar in the last half of 2008 which bolstered our realized crude oil prices and refined product crack spreads, both of which are denominated in U.S. dollars.

Our upstream operations averaged production of 55,932 boe/d in 2008 as compared to 60,336 boe/d in the prior year, reflecting a 7% reduction. Our production in 2008 reflects a modest 4% decline as compared to the 58,416 boe/d averaged in the Fourth Quarter of 2007 as our reduced capital program in 2008 and net acquisitions substantially stabilized our production. In 2007, we benefited from a $148.5 million drilling effort in the First Quarter boosting production to an average of 62,024 boe/d for the quarter as compared to capital expenditures of $79.6 million in the First Quarter of 2008. In 2008, we shifted our efforts to the re-pressurization of a few of our larger oil reservoirs rather than further development drilling and are expecting longer term more stable benefits, as compared to the flush production and accelerated declines associated with some drilling programs. Our operating costs of $300.9 million in 2008 are unchanged from the prior year as the overheated Alberta oilfield services industry did not weaken until late in the year with continued weakening expected in 2009. Our operating netback of $47.89 per boe represents a 60% increase over the prior year and is primarily attributed to higher commodity prices and tightening heavy crude oil differentials in western Canada.

During the Third Quarter of 2008, we completed two acquisitions for an aggregate cash consideration of $167.6 million to acquire approximately 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas which represents an acquisition cost of approximately $63,000 per flowing boe. The principal asset acquired was a large pool of medium gravity oil of which approximately 7% of the original oil in place has been recovered and it is anticipated that with a combination of additional drilling and reservoir management, the recoveries from this pool can be substantially improved. In addition to numerous minor acquisitions/dispositions, we disposed of 481 boe/d of natural gas and natural gas liquids production for $36.8 million, representing proceeds of approximately $76,000 per flowing boe.

Reserve additions in our upstream operations replaced our production during 2008 with our proved plus probable reserves at December 31, 2008 totaling 219.9 million boe substantially unchanged from 220.9 million boe at the end of 2007. Including changes in future development costs, our 2008 finding and development costs averaged $25.97 per boe of proved reserves as compared to $28.44 per boe in the prior year and a three year average of $27.27 per boe while our finding and development costs averaged $29.87 per boe for proved plus probable reserves as compared to $28.10 per boe in the prior year and a three year average of $28.00 per boe. Including changes in future development costs, our 2008 finding, development and acquisition costs averaged $27.90 per boe of proved reserves as compared to $26.98 per boe in the prior year and a three year average of $28.78 per boe while on a proved plus probable basis, our costs were $28.84 per boe in 2008 as compared to $22.97 per boe in the prior year and a three year average of $25.47 per boe, respectively. Proved plus probable reserve additions are 13.7 million boe attributed to our 2008 capital program, enhanced oil recovery plans and new undeveloped reserves which, when coupled with the 5.8 million boe acquired during the year, substantially offsets our 2008 production. Relative to our 2008 netback price of $47.89, our finding and development costs represent a recycle ratio of 1.6 while our finding, development and acquisition costs represent a recycle ratio of 1.7.

During 2008, our downstream operations generated $83.6 million of cash as compared to $165.0 million in the prior year with the reduced contribution primarily the result of an $86.8 million drop in gross margin. The drop in North American demand for gasoline that began in mid-2007 continued through 2008 with the slowing US economy and record high prices curtailing consumer driving. As a result, the gasoline crack spread weakened significantly from the US$28.76 averaged during the Second Quarter of 2007 culminating in a negative spread during the Fourth Quarter of 2008. Similarly, the prices for high sulphur fuel oil ("HSFO") during the first half of 2008 did not proportionately reflect increases in crude oil prices resulting in a significant deterioration of the HSFO crack spread which averaged US$38.75 less than the West Texas Intermediate ("WTI") benchmark price of US$123.98/bbl during the Second Quarter of 2008 as compared to an average of US$26.52/bbl less than the WTI benchmark for the entire year. In contrast, the strong global demand for distillate products improved the refining margins for heating oil, diesel and jet fuel. Overall, our refining margin in 2008 was US$7.16 per barrel of throughput, a drop of $2.89 per barrel from the prior year.

Our refinery throughput averaged 103,497 bbls/d during 2008 with First Quarter throughput of approximately 112,000 bbls/d somewhat tempered by a four day unplanned outage. Throughput in May through August was reduced to approximately 95,500 bbls/d to optimize margins by minimizing the production of HSFO and reduced to approximately 102,800 bbls/d from September through December due to fouling of heat exchangers. Average daily throughput in 2008 represents a utilization factor of 90% as compared to the refinery's 115,000 bbls/d nameplate capacity. As compared to the prior year with $34.5 million of turnaround and catalyst costs incurred during an extensive shutdown in the Fourth Quarter, our refinery operations incurred $5.6 million of turnaround and catalyst costs during a partial turnaround of the visbreaker unit in 2008. Our refinery operating costs totaled $78.9 million ($2.08 per bbl of throughput) in 2008 as compared to $83.9 million ($2.33 per bbl of throughput) in the prior year while our cost of purchased energy was $131.9 million ($3.48 per bbl) in the current year as compared to $92.3 million ($2.57 per bbl) in 2007 which when aggregated totals $5.56 per barrel of throughput for 2008 as compared to $4.90 in the prior year, a net increase of $0.66 per barrel.

In 2008, the strength in commodity prices resulted in cash settlements paid of $225.2 million on our price risk management contracts during the first nine months of 2008, offset somewhat by $24.4 million received during the Fourth Quarter of the year as commodity prices weakened significantly.

In April 2008, we raised $239.5 million of net proceeds with the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures and applied the net proceeds to reduce borrowings under our Extendible Revolving Credit Facility. As the disruptions in the capital markets continued in 2008, we have deferred our request to extend the maturity date of our credit facility beyond April 2010 in an effort to maintain the cost of our bank borrowing as well as retain our $1.6 billion of credit capacity.

In 2008, we declared distributions to Unitholders totaling $551.3 million ($3.60 per Trust Unit) as compared to $610.3 million ($4.40 per Trust Unit) in 2007. We have maintained a monthly distribution of $0.30 per Trust Unit since November 2007 and in light of the significant reduction in commodity prices, we have declared a distribution of $0.05 per Trust Unit for Unitholders of record on March 23, 2009 and payable on April 15, 2009. In the near term, substantially all of our cash flow from operating activities will be directed to enhancing Unitholder value through capital expenditures focused on maintaining our productive capacity as well as low risk profit/growth initiatives with the remaining cash directed towards improving our balance sheet liquidity by repaying bank borrowings.

Business Segments

The following table presents selected financial information for our two business segments:

	Year Ended December 31					
	2008			2007		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[1]	**1,294,769**	**4,194,595**	**5,489,364**	971,044	3,098,556	4,069,600
Earnings From Operations[2]	**498,786**	**14,125**	**512,911**	169,423	92,270	261,693
Capital expenditures	**271,312**	**56,162**	**327,474**	300,674	44,111	344,785
Total assets[3]	**3,933,632**	**1,775,688**	**5,745,407**	3,952,337	1,482,904	5,451,683

(1) Revenues are net of royalties.

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

(3) Total assets on a consolidated basis as at December 31, 2008 include $36.1 million (2007 - $16.4 million) relating to the fair value of risk management contracts.

Our upstream and downstream operations are each discussed separately in the sections that follow. Additionally, we have included a section entitled "Risk Management, Financing and Other" that discusses, among other things, our cash flow risk management program.

UPSTREAM OPERATIONS

2008 Highlights

- Operating cash flow of $945.9 million, an improvement of $321.6 million over the prior year, reflecting the year-over-year strength of crude oil prices as well as a tightening of quality differentials.
- Average production of 55,932 boe/d as compared to production of 60,336 boe/d in the prior year reflects higher decline rates in 2007 and a reduction in 2008 capital spending.
- Operating costs of $300.9 million were unchanged from the prior year, representing $14.70/boe in the current year as compared to $13.66/boe in the prior year.
- Operating netback of $47.89/boe, representing an $18.00/boe (60%) increase over the prior year, attributed to substantially higher commodity prices.

- Completion of two acquisitions for aggregate cash consideration of $167.6 million, to acquire 2,650 boe/d of production representing an average cost per flowing barrel of approximately $63,000 comprised of 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas, offset by divestments of $46.5 million and 640 boe/d.
- Capital spending of $271.3 million included the drilling of 247 wells (150.3 on a net basis) with a 100% success rate plus $128.8 million in net acquisitions, replaced 2008 production with finding and development costs, including changes in future development costs, of $25.97 per boe of proved reserves and $29.87 per boe for proved plus probable reserves.

Summary of Financial and Operating Results

	Year Ended December 31		
(in $000s except where noted)	**2008**	2007	Change
Revenues	**1,543,214**	1,184,457	30%
Royalties	**(248,445)**	(213,413)	16%
Net revenues	**1,294,769**	971,044	33%
Operating expenses	**300,890**	300,918	0%
General and administrative	**32,868**	34,615	(5%)
Transportation and marketing	**13,490**	11,946	13%
Depreciation, depletion, amortization and accretion	**448,735**	454,142	(1%)
Earnings From Operations(1)	**498,786**	169,423	194%
Cash capital expenditures (excluding acquisitions)	**271,312**	300,674	(10%)
Property and business acquisitions, net of dispositions	**128,773**	138,158	(7%)
Daily sales volumes			
Light to medium oil (bbl/d)	**25,093**	27,165	(8%)
Heavy oil (bbl/d)	**12,162**	14,469	(16%)
Natural gas liquids (bbl/d)	**2,624**	2,412	9%
Natural gas (mcf/d)	**96,315**	97,744	(1%)
Total (boe/d)	**55,932**	60,336	(7%)

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

Commodity Price Environment

	Year Ended December 31		
Benchmarks	**2008**	2007	Change
West Texas Intermediate crude oil (US$ per barrel)	**99.65**	72.31	38%
Edmonton light crude oil ($ per barrel)	**102.02**	76.25	34%
Bow River blend crude oil ($ per barrel)	**84.10**	53.36	58%
AECO natural gas daily ($ per mcf)	**8.14**	6.45	26%
Canadian / U.S. dollar exchange rate	**0.943**	0.935	1%

The following graph summarizes benchmark commodity prices for our upstream production for the period of January 2007 to December 2008:

During 2008, the average WTI benchmark price was 38% higher than the prior year. The average Edmonton light crude oil price ("Edmonton Par") also increased from the prior year to average $102.02 in 2008, an increase of 34%. The increase in Edmonton Par has been less than the increase in WTI due to weaker demand for light crude oil in western Canada as a result of refineries converting to heavier crude blends coupled with the modest strengthening of the Canadian dollar relative to the U.S. dollar in 2008.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets and the seasonal demand for heavy oil. During 2008, the Bow River heavy oil differential relative to Edmonton Par tightened to an average of $17.92/bbl (or 17.6%) compared to $22.89/bbl (or 30.0%) in 2007. On a per barrel basis, heavy oil differentials tightened throughout the year as production shortfalls and increased refinery demand for heavier grades of oil put upward pressure on pricing.

	2008				2007			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par ($/bbl)	**14.07**	**16.48**	**21.50**	**19.63**	29.51	23.87	21.12	17.06
Bow River Blend differential as a % of Edmonton Par	**22.2%**	**13.5%**	**17.1%**	**20.2%**	34.2%	30.0%	29.4%	25.4%

Compared to the prior year, the average AECO daily natural gas price was 26% higher during the year ended December 31, 2008. Natural gas prices have strengthened in 2008 relative to 2007 due to a general strengthening of commodity prices.

Realized Commodity Prices[1]

The following table summarizes our average realized price by product for 2008 and 2007.

	Year Ended December 31		
	2008	2007	Change
Light to medium oil ($/bbl)	**89.72**	64.09	40%
Heavy oil ($/bbl)	**77.22**	46.71	65%
Natural gas liquids ($/bbl)	**75.16**	62.26	21%
Natural gas ($/mcf)	**8.60**	6.94	24%
Average realized price ($/boe)	**75.39**	53.78	40%

(1) Realized commodity prices exclude the impact of price risk management activities.

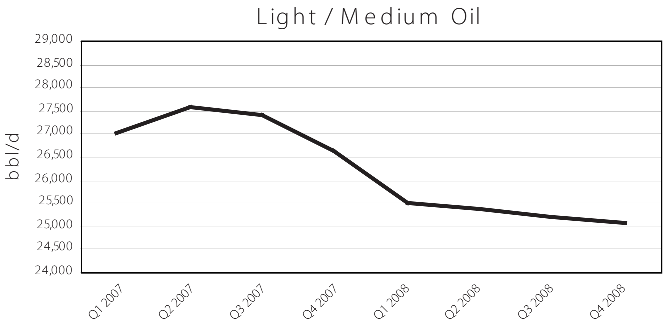
Our realized price for light to medium oil sales increased by $25.63/bbl (or 40%) compared to the prior year, reflecting the $25.77/bbl (or 34%) increase in Edmonton Par pricing. Harvest's heavy oil price increased by $30.51/bbl (or 65%) compared to the prior year, reflecting the $30.74/bbl (or 58%) increase in the Bow River price. Our average realized price for our natural gas production increased by $1.66/mcf (or 24%) compared to the prior year, reflecting the $1.69/mcf (or 26%) increase in AECO daily pricing over the year.

Sales Volumes

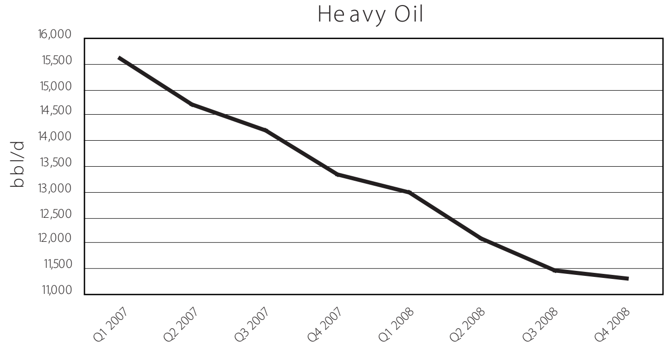
The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2008		2007		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**25,093**	**45%**	27,165	45%	(8%)
Heavy oil (bbl/d)	**12,162**	**22%**	14,469	24%	(16%)
Natural gas liquids (bbl/d)	**2,624**	**5%**	2,412	4%	9%
Total liquids (bbl/d)	**39,879**	**72%**	44,046	73%	(9%)
Natural gas (mcf/d)	**96,315**	**28%**	97,744	27%	(1%)
Total oil equivalent (boe/d)	**55,932**	**100%**	60,336	100%	(7%)

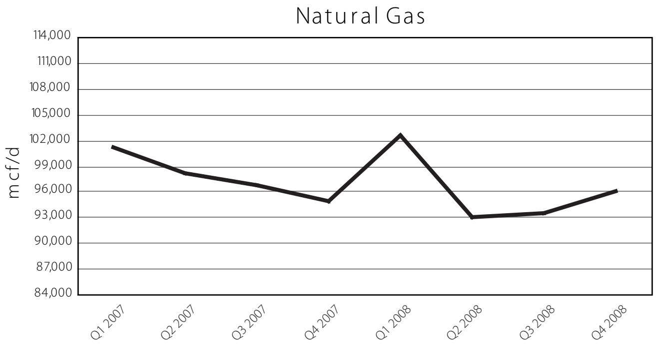
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24o (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy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



Harvest's average daily production of light/medium oil in 2008 was 25,093 bbl/d, a 2,072 bbl/d or 8% reduction from the prior year. The 8% reduction is mainly attributed to a lower lever of drilling activity in 2008 and the initial flush production from wells completed in early 2007 stabilized at lower rates by the end of 2007. Light/medium production in 2008 has continued to remain relatively consistent as compared to the 2007 exit rate of production as increased water cuts and production lost to downtime have been substantially offset by new wells drilled in 2008 and the production from acquisitions completed during the Third Quarter. Production at our largest area, Hay River, has remained constant over the past year reflecting our increased water injection in early 2008 which improved recovery.



Our heavy oil production has decreased steadily over the past twelve months resulting in a 16% reduction with year-to-date production of 12,162 bbl/d as compared to 14,469 bbl/d in 2007. This reduction is largely the result of cold and wet weather related operational problems in the first half of 2008. Additionally, increased water cuts on our larger producing wells in the west central Saskatchewan and Lloydminster areas were only partially offset by new wells drilled in the year.



Our 2008 natural gas production decreased by 1% relative to 2007, averaging 96,315 mcf/d. Harvest's 2008 average daily production is lower than in 2007 due to continued declines and production disruptions throughout the Fourth Quarter of 2007 and Second Quarter 2008 offset by incremental production resulting from our 2008 winter drilling program, acquisitions completed in the Third Quarter of 2008, and improved run time on our largest producing wells in the Fourth Quarter of 2008.

Revenues

	Year Ended December 31		
(000s)	**2008**	2007	Change
Light to medium oil sales	**$ 824,014**	$ 635,470	30%
Heavy oil sales	**343,717**	246,674	39%
Natural gas sales	**303,303**	247,499	23%
Natural gas liquids sales and other	**72,180**	54,808	32%
Total sales revenue	**1,543,214**	1,184,451	30%
Royalties	**(248,445)**	(213,413)	16%
Net Revenues	**$ 1,294,769**	$ 971,038	33%

Our revenue is impacted by changes to production volumes, commodity prices and currency exchange rates. Our 2008 total sales revenue of $1,543.2 million is $358.8 million higher than the prior year, of which $442.4 million is attributed to higher realized prices offset by a $83.6 million negative variance in respect of lower production volumes. The price increase reflects the 34% increase in Edmonton Par pricing and the 26% increase in AECO daily natural gas pricing in 2008 as compared to 2007, while our decreased production volume is attributed to decline rates, particularly in 2007, and a reduction in 2008 capital spending.

As discussed earlier, light to medium oil sales revenue for 2008 was $188.5 million higher than the prior year due to a $235.4 million favourable price variance offset by a $46.9 million unfavourable volume variance. Heavy oil sales revenue of $343.7 million in 2008 was $97.0 million higher than in the prior year due to a $135.8 million favourable price variance offset by a $38.8 million unfavourable volume variance. Natural gas sales revenue increased by $55.8 million in 2008 compared to 2007 due to a $58.8 million favourable price variance offset by a $3.0 million unfavourable volume variance.

During 2008, natural gas liquids and other sales revenue increased by $17.4 million compared to the prior year resulting from a $12.4 million favourable price variance and a $5.0 million favourable volume variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production. The positive volume variance is attributed to a few natural gas wells drilled near the end of 2007 and throughout 2008, which yielded significant natural gas liquids.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices.

Throughout 2008, net royalties as a percentage of gross revenue were 16.1% (2007 - 18.0%) and aggregated to $248.4 million (2007 - $213.4 million) Our royalty rate for the year was slightly lower than the expected rate of 17% due to various credits received throughout the year.

Operating Expenses

	Year Ended December 31				
	2008		2007		
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 80,162**	**$ 3.92**	$ 64,053	$ 2.91	35%
Well Servicing	**52,561**	**2.57**	59,500	2.70	(5%)
Repairs and maintenance	**51,462**	**2.51**	50,244	2.28	10%
Lease rentals and property taxes	**27,953**	**1.37**	23,803	1.08	27%
Processing and other fees	**15,073**	**0.74**	17,556	0.80	(8%)
Labour – internal	**23,785**	**1.16**	22,757	1.03	13%
Labour – contract	**17,128**	**0.84**	15,511	0.70	20%
Chemicals	**15,968**	**0.78**	14,910	0.68	15%
Trucking	**11,297**	**0.55**	11,833	0.54	2%
Other	**5,501**	**0.26**	20,751	0.94	(72%)
Total operating expense	**$ 300,890**	**$ 14.70**	$ 300,918	$ 13.66	8%
Transportation and marketing expense	**$ 13,490**	**$ 0.66**	$ 11,946	$ 0.54	22%

Our 2008 operating costs totaled $300.9 million, unchanged from 2007. On a per barrel basis, operating costs have increased to $14.70/boe as compared to $13.66/boe in the prior year, an 8% increase substantially attributed to reduced production volumes. The largest components of operating expense are power and fuel costs, well servicing, and repairs and maintenance costs. Well servicing and repairs and maintenance costs continue to reflect the high demand for oilfield services, although with reduced activity compared to the prior year, these costs have remained relatively stable.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 27% of our total operating costs during 2008. The average Alberta electric power price of $89.95/MWh in the year was 35% higher than the average 2007 price of $66.84/MWh and this increase is reflected in our 35% per boe increase in power and fuel costs compared to the prior year. To mitigate our exposure to electric power price fluctuations we had electric power price risk management contracts in place which resulted in a gain of $10.0 million compared to a gain of $3.1 million in the prior year. The risk management contracts for electric power costs ended in December 2008 and accordingly our electricity usage in Alberta will be exposed to market prices beginning January 1, 2009. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Year Ended December 31		
(per boe)	**2008**	2007	Change
Electric power and fuel costs	**$ 3.92**	$ 2.91	35%
Realized gains on electricity risk management contracts	**(0.49)**	(0.14)	250%
Net electric power and fuel costs	**$ 3.43**	$ 2.77	24%
Alberta Power Pool electricity price (per MWh)	**$ 89.95**	$ 66.84	35%

Transportation and marketing expense for 2008 was $13.5 million or $0.66/boe, an increase of 22% per boe from $11.9 million or $0.54 per boe in 2007. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our natural gas production volumes while the cost per boe typically remains relatively constant. The increased transportation and marketing expense in 2008 is primarily due to increased clean oil trucking costs associated with the two acquisitions completed in the Third Quarter.

Operating Netback

	Year Ended December 31	
(per boe)	**2008**	2007
Revenues	**$ 75.39**	$ 53.78
Royalties	**(12.14)**	(9.69)
Operating expense	**(14.70)**	(13.66)
Transportation and marketing expense	**(0.66)**	(0.54)
Operating netback[(1)]	**$ 47.89**	$ 29.89

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

Harvest's operating netback represents the net amount realized on a per boe basis after deducting directly related costs. In 2008, our operating netback increased by $18.00/boe or 60% over the prior year. The increase in our operating netback is primarily attributed to a $21.61/boe increase in realized commodity prices, reflecting the increase in Edmonton Par, Bow River and AECO pricing over the prior year, offset by an increase in royalties of $2.45/boe resulting from higher realized prices.

General and Administrative ("G&A") Expense

	Year Ended December 31		
(000s except per boe)	**2008**	2007	Change
Cash G&A	**$ 33,643**	$ 31,892	5%
Unit based compensation expense (recovery)	**(775)**	2,723	(128%)
Total G&A	**$ 32,868**	$ 34,615	(5%)
Cash G&A per boe ($/boe)	**$ 1.64**	$ 1.45	13%

For the year ended December 31, 2008, Cash G&A costs increased by $1.8 million (or 5%) compared to the prior year, reflecting higher employee costs in a continued tight market for technically qualified staff in the western Canadian petroleum and natural gas industry. Generally, approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provide employees with the option of settling outstanding awards with cash. As a result, unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. The market price of our Trust Units was $20.63 at December 31, 2007 and on December 31, 2008, the price was $10.50. Total unit based compensation expense decreased $3.5 million in 2008 compared to 2007 as the market price of Harvest Trust Units decreased by $10.13 per Trust Unit in 2008 which was greater than the $5.60 per Trust Unit decrease in 2007.

Depletion, Depreciation, Amortization and Accretion Expense

	Year Ended December 31		
(000s except per boe)	**2008**	2007	Change
Depletion, depreciation and amortization	**$ 414,969**	$ 420,184	(1%)
Depletion of capitalized asset retirement costs	**15,135**	15,621	(3%)
Accretion on asset retirement obligation	**18,631**	18,337	2%
Total depletion, depreciation, amortization and accretion	**$ 448,735**	$ 454,142	(1%)
Per boe	**$ 21.92**	$ 20.62	6%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2008 was $5.4 million lower compared to the prior year. The decrease is attributed to lower production volumes partially offset by slightly higher finding, development and acquisition costs that have increased our depletion rate compared to the same periods of the prior year.

Capital Expenditures

	Year Ended December 31	
(000s)	**2008**	2007
Land and undeveloped lease rentals	**$ 7,762**	$ 2,785
Geological and geophysical	**6,782**	6,058
Drilling and completion	**164,628**	146,941
Well equipment, pipelines and facilities	**81,680**	134,423
Capitalized G&A expenses	**10,235**	8,353
Furniture, leaseholds and office equipment	**225**	2,114
Development capital expenditures excluding acquisitions and non-cash items	**271,312**	300,674
Non-cash capital additions (recoveries)	**(251)**	371
Total development capital expenditures excluding acquisitions	**$ 271,061**	$ 301,045

In 2008, approximately 61% of our development capital expenditures were incurred to drill 247 gross wells with a success rate of 100%, compared to 182 gross wells with a success rate of 98% in 2007. While we continued to focus our drilling activity on oil opportunities (68% of net wells drilled) given the strong oil price environment through most of the year, our natural gas drilling in central Alberta resulted in some particularly successful wells. At Chedderville, we benefited from our 2006 exploration discovery with the drilling of 3 additional wells into this prolific Mannville channel. Additional pipeline infrastructure was completed by the end of the year and the wells were brought on stream bringing our production from this once undeveloped area to approximately 1,800 boe/d.

Over 80% of our 2008 drilling activity focused on our Markerville, Lloydminster/Hayter, southeast Saskatchewan, southeast Alberta and Rimbey properties. In Markerville we drilled 63 gross wells focusing on infill opportunities in our Edmonton sands shallow gas play as well as deeper targets in the Ostracod and Ellerslie channel systems. At Lloydminster/Hayter, we drilled 34 gross wells, primarily horizontal wells targeting infill locations in both the Lloydminster and Dina sandstone formations. In southeast Saskatchewan, we drilled 45 gross horizontal wells pursuing light oil accumulations in both the Souris Valley and Tilston formations with a 100% success rate. A horizontal test well into the Bakken formation provided us with information to further assess the Bakken potential on Harvest's Bakken rights of approximately 12,000 net acres. In southeast Alberta, we drilled 40 gross wells including the transferring of our horizontal well experience in Lloydminster to the development of a new heavy oil play in the Sunburst sandstone formation at Murray Lake where we drilled 4 horizontal wells. At Rimbey, we continued to pursue primarily gas opportunities by drilling 21 gross wells to continue our successful exploration activities pursuing Ostracod channel sands as well as shallow Edmonton sands opportunities.

Our enhanced oil recovery ("EOR") efforts continue. At Hay River, rather than executing a large drilling program, we focused on enhancing our infrastructure and water injection to better manage the performance of our Bluesky reservoir. By increasing injection in early 2008, we were able to maintain our production levels throughout 2008 without drilling any new wells, our December 2008 production was 1,600 boe/d ahead of our original expectations.

At Bellshill Lake, an independent engineering study, as well as field trials, confirmed that increased water injection would reduce our production decline rate and result in an overall improved recovery from this large Ellerslie medium gravity oil pool. In 2008, we completed the installation of a water transfer line from our south Bellshill pool to bring incremental produced water to our main Bellshill Lake pool which has allowed us to further increase the volume of water injection in the Fourth Quarter of 2008.

At Suffield, we launched an enhanced water flood pilot with the installation of a water transfer line from our main Batus facility to our Lark oil pool. Suffield produces heavy gravity oil from Basal Quartz sandstone reservoirs and produced water collected from a number of separate oil pools (including Lark) was not re-distributed to the pools resulting in reduced reservoir pressure as fluids were produced over time. By redistributing water from Batus to the other pools, we will be able to access incremental oil reserves as we "re-charge" the reservoirs. Our main Batus reservoir will also benefit as we will be reducing the amount of "over-injection" which can result in this heavier oil being bypassed in favor of the more mobile water. Injection was initiated in the Third Quarter of 2008.

At Wainwright, we completed the majority of our laboratory testing and completed the acquisition of our polymer injection skid with injection scheduled to begin late in the First Quarter of 2009. The polymer injection represents the first phase of our pilot testing the enhanced recovery impact on this medium gravity Sparky oil pool. We will be initially testing the benefit of polymer injection alone, to be followed up with an Alkaline Surfactant Polymer pilot should the test results be favorable.

The $81.7 million of well equipment, pipelines and facilities expenditures during 2008 includes the equipping of wells drilled during the year, and also a number of infrastructure initiatives to optimize the production performance of our asset base. Approximately $9 million was invested at various properties to ensure the integrity of our transportation and processing infrastructure. At Chedderville, we completed an expansion to our gathering infrastructure for approximately $1 million to allow new wells to be brought on stream, and to fully optimize the production from our original discovery well. At southeast Saskatchewan, we installed a free water knockout vessel at our Kenossee pool for total capital of approximately $1 million to allow production to be optimized from our infill and step out drilling program. Approximately $8 million was part of our EOR implementation at Bellshill Lake, Suffield, Hay River and Wainwright as noted above.

The following summarizes Harvest's participation in gross and net wells drilled during 2008:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross**[1]	**Net**	**Gross**	**Net**	**Gross**	**Net**
Southeast Saskatchewan	45.0	35.5	45.0	35.5	-	-
Southeast Alberta	40.0	15.5	40.0	15.5	-	-
Red Earth	12.0	11.3	12.0	11.3	-	-
Suffield	12.0	12.0	12.0	12.0	-	-
Lloydminster/Hayter	34.0	31.8	34.0	31.8	-	-
Rimbey	21.0	7.3	21.0	7.3	-	-
Markerville	63.0	26.9	63.0	26.9	-	-
Northwest Alberta	10.0	3.8	10.0	3.8	-	-
Other Areas	10.0	6.2	10.0	6.2	-	-
Total	247.0	150.3	247.0	150.3	-	-

(1) Excludes 18 additional wells that we have an overriding royalty interest in.

Our 2008 capital program, along with our acquisitions and divestitures, replaced our production on a proved plus probable basis with 2008 year end reserves of 219.9 million boe, substantially unchanged from 220.9 million boe at the end of 2007. Including changes in future development costs, our 2008 finding and development costs averaged $25.97 per boe of proved reserves while our finding, development and acquisition costs averaged $27.90 per boe of proved reserves as compared to $28.44/boe and $26.98/boe, respectively, in the prior year and a three year average of $27.27/boe and $28.78/boe, respectively. Based on the forecast prices and costs of our independent reservoir engineers as at December 31, 2008, the net present value of our future net revenues from proved reserves using a 10% discount rate is $2,941.8 million and $3,893.8 million from proved plus probable reserves. With 2008 netback price of $47.89/boe in 2008, our finding and development costs result in a recycle ratio of 1.6 while our finding, development and acquisition costs result in a recycle ratio of 1.7. Based on our 2008 production of 20.5 million boe, our 2008 year end proved reserves represent a reserve life index of 7.5 years while our proved plus probable reserves represent a reserve life index of 10.8 years.

Acquisitions and Divestitures

In late July 2008, we acquired a private oil and natural gas company for cash consideration of $36.8 million. The associated production was approximately 390 bbl/d of light oil in an area immediately adjacent to our existing operations in Red Earth plus 2,300 mcf/d of natural gas from a shallow gas play in north central Alberta. An independent engineering report prepared effective April 1, 2008 estimated proved and probable reserves of 1,800 mboe.

In early September 2008, we acquired conventional oil and gas properties in the Peace River Arch area of northern Alberta with approximately 1,900 boe of daily production (66% oil and 24% natural gas) in exchange for cash consideration of $130.8 million plus some minor natural gas interests which produced approximately 85 boe/d during the first half of 2008. During the first half of 2008, the acquired properties averaged production of approximately 1,255 bbl/d of light gravity oil and natural gas liquids plus 3,900 mcf/d of natural gas. An independent engineering report prepared effective December 31, 2007 estimated proved reserves at 7,260 mboe and proved plus probable reserves at 9,899 mboe.

During the Third Quarter, we disposed of various non-operated properties in the Pouce Coupe area in exchange for cash consideration of $36.8 million plus some freehold mineral interests in southeast Saskatchewan. These properties had average daily production of approximately 2,800 mcf/d of natural gas and 14 boe/d of natural gas liquids.

Goodwill

Goodwill is recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At December 31, 2008, we had $677.6 million of goodwill on our balance sheet related to our upstream segment, of which $0.8 million was added during 2008 with our purchase of a private oil and natural gas company. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. Although commodity prices decreased significantly in the second half of 2008 no goodwill impairment charges have been made due to the historical cost of the oil assets, which were acquired based on oil prices consistent or lower compared to prices prevalent in the market today.

Asset Retirement Obligation ("ARO")

In connection with property acquisitions and development expenditures, we record the fair value of the ARO as a liability in the same year the expenditures occur. The associated asset retirement costs are capitalized as part of the carrying amount of the assets and are depleted and depreciated over our estimated net proved reserves. Once the initial ARO is measured, it is adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $63.8 million during 2008 as a result of accretion expense of $18.6 million, new liabilities recorded of $7.2 million, and upward revisions in estimates of $49.4 million, offset by $11.4 million of actual asset retirement expenditures incurred.

DOWNSTREAM OPERATIONS

2008 Highlights

- Cash from downstream operations totaled $83.6 million (2007 - $165.0 million) with sound operating performance more than offset by generally lower refining margins, higher costs for purchased energy and, in the Fourth Quarter, an inventory write-down due to significantly lower commodity prices.
- An average refining margin of US$7.16/bbl reflects a US$2.89 decrease over the prior year primarily attributed to lower margins on gasoline and high sulphur fuel oil ("HSFO") products partially offset by improved margins on distillate products and higher discounts on feedstock, all relative to the WTI benchmark price.

- Refinery throughput averaged 103,497 bbls/d, representing a 90% utilization rate, with throughput limited from May through August in an effort to optimize refining margins by minimizing the production of HSFO and from September through December due to fouling of heat exchangers.
- Refining operating costs of $2.08/bbl of throughput as compared to $2.33/bbl in the prior year reflects increased throughput and cost containment efforts resulting in a relatively stable level of spending at $78.9 million.
- Cost of purchased energy increased to $3.48/bbl of throughput as compared to $2.57/bbl in the prior year reflecting a significantly higher commodity price environment during the first three quarters of 2008, while turnaround and catalyst costs reflect a modest visbreaker turnaround in 2008 as compared to an extensive shutdown in 2007.
- Capital spending totaled $56.2 million as compared to $44.1 million in the prior year with $30.1 million incurred for the visbreaker expansion project commissioned in November 2008.

Summary of Financial and Operational Results

	Year Ended December 31		
(in $000's except where noted below)	**2008**	2007	Change
Revenues	**4,194,595**	3,098,556	35%
Purchased feedstock for processing and products purchased for resale[4]	**3,850,507**	2,667,714	44%
Gross margin[1]	**344,088**	430,842	(20%)
Costs and expenses			
Operating expense	**98,736**	102,476	(4%)
Purchased energy expense	**131,878**	92,328	43%
Turnaround and catalyst expense	**5,645**	34,486	(84%)
Marketing expense and other	**20,753**	34,970	(41%)
General and administrative expense	**1,875**	1,713	9%
Depreciation and amortization expense	**71,076**	72,600	(2%)
Earnings From Operations[1]	**14,125**	92,269	(85%)
Cash capital expenditures	**56,162**	44,111	27%
Feedstock volume (bbl/day)[2]	**103,497**	98,617	5%
Yield (000's barrels)			
Gasoline and related products	**12,068**	11,515	5%
Ultra low sulphur diesel and jet fuel	**15,668**	14,406	9%
High sulphur fuel oil	**9,952**	9,843	1%
Total	**37,688**	35,764	5%
Average refining margin (US$/bbl)[3]	**7.16**	10.05	(29%)

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(2) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.
(3) Average refining margin is calculated based on per barrel of feedstock throughput.
(4) Purchased feedstock for processing and products purchased for resale includes inventory write-downs of $35.3 million in the Fourth Quarter of 2008.

Overview of Downstream Operations

Our downstream operations are comprised of an 115,000 bbls/d medium gravity sour crude oil hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador. Our petroleum marketing business is comprised of the retail and wholesale distribution of gasoline, diesel, jet and other transportation fuels as well as home heating fuels and related appliances and the revenues from our marine services including tugboat revenues.

The financial performance of our refinery reflects its throughput, feedstock selection, operating effectiveness, refining margins and operating costs. Our refining margin is dependent on the sales value of the refined products produced and the cost of crude oil feedstock purchased as well as the yield of refined products from various crude oil feedstocks. We continuously evaluate the market and relative refinery values of several different crude oils and vacuum gas oils to determine the optimal feedstock mix. We analyze our refining margin on each refined product and our sales revenue relative to benchmark prices for the refined product and the WTI benchmark price. With respect to feedstock costs, we analyze our price discounts relative to the WTI benchmark price and segregate crude oil sources by country of origin.

We purchase substantially all of our refinery feedstock and sell our distillate and gasoline products, with the exception of products sold in Newfoundland through our petroleum marketing division, to Vitol Refining S.A. ("Vitol") pursuant to the Supply and Offtake Agreement. Effective January 20, 2008, our HSFO is sold to a wholly-owned affiliate of one of the world's largest integrated energy companies; prior to this, our HSFO had been sold to Vitol. During the year ended December 31, 2008, approximately 67% of our refined product sales were to Vitol.

The Supply and Offtake Agreement with Vitol contains pricing terms that reflect market prices based on an average ten day delay which results in our purchases from and sales to Vitol being priced on future prices as compared to pricing at the time of delivery. With the exception of the sales to Vitol, our refined products are sold at prices that reflect market prices at the time that the product is delivered to the purchaser. For more information on the Supply and Offtake Agreement with Vitol, see the description in our Annual Information Form for the year ended December 31, 2007 as filed on SEDAR at www.sedar.com.

For the year ended December 31, 2008, our refining gross margin was $287.6 million as compared to $386.7 million in the prior year, a decrease of $99.1 million. The decrease in refining gross margin is primarily due to weaker gasoline and HSFO margins which resulted in negative price variances of $224.9 million and $66.5 million, respectively, partially offset by improved distillate margins and improved discounts to WTI on our feedstock which resulted in positive price variances of $92.3 million and $121.7 million, respectively.

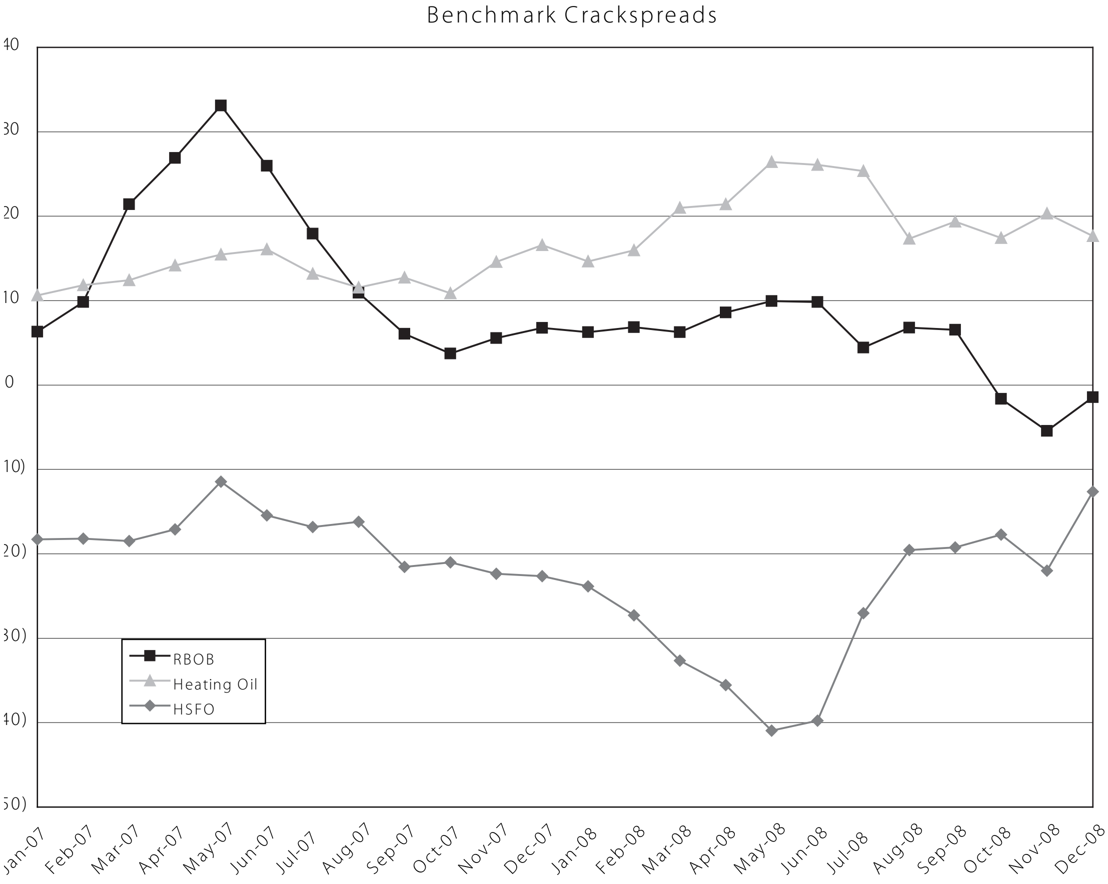
For the year ended December 31, 2008, our marketing division earned a gross margin of $56.5 million as compared to $44.1 million in the prior year, an increase of 28% primarily due to a significant increase in the price of sulphur, which is sold through a profit sharing agreement with a third party processor and contributed $8.5 million in 2008 as compared to $0.3 in 2007.

Refining Benchmark Prices

The following average benchmark prices and currency exchange rates are the reference points from which we discuss our refinery's financial performance:

	Year Ended December 31		
	2008	2007	Change
WTI crude oil (US$/bbl)	**99.65**	72.31	38%
Brent crude oil (US$/bbl)	**98.38**	72.67	35%
Basrah Official Sales Price Discount (US$/bbl)	**(7.40)**	(6.84)	8%
RBOB gasoline (US$/bbl/gallon)	**104.40/2.49**	86.86/2.07	20%
Heating Oil (US$/bbl/gallon)	**119.89/2.85**	85.65/2.04	40%
High Sulphur Fuel Oil (US$/bbl)	**73.13**	54.02	35%
Canadian / U.S. dollar exchange rate	**0.943**	0.935	1%

The following graph summarizes the crack spreads between the respective benchmark prices for refined products and WTI for the period of January 2007 to December 2008:



During 2008, the Heating Oil Crack Spread averaged US$20.24/bbl, an increase of US$6.90/bbl over the US$13.34/bbl averaged in the prior year, as strong demand for distillate products in North America, Europe and Asia improved margins. The RBOB Gasoline Crack Spread averaged US$4.75/bbl in 2008, a drop of US$9.80/bbl from the US$14.55/bbl averaged in the prior year, as North American demand for gasoline continued to weaken subsequent to June 2007 due to slowing economic activity and consumer response to the record setting prices for gasoline in the summer of 2008. Similarly, the HSFO Crack Spread differential averaged US$26.52/bbl less than WTI in 2008, an increase of US$8.23/bbl from the average differential of US$18.29/bbl less than WTI in the prior year, as margins in the Second Quarter of 2008 were particularly weak.

During 2008, the Canadian/U.S. dollar exchange rate averaged 0.943, an increase of 0.008 from the prior year. The relative strength of the Canadian dollar resulted in a nominal decrease in our cash flows from downstream operations in 2008, as refined product and crude oil prices are denominated in U.S. dollars.

Summary of Gross Margin

The following table summarizes our downstream gross margin for the years ended December 31, 2008 and 2007 segregated between refining activities and petroleum marketing and other related businesses.

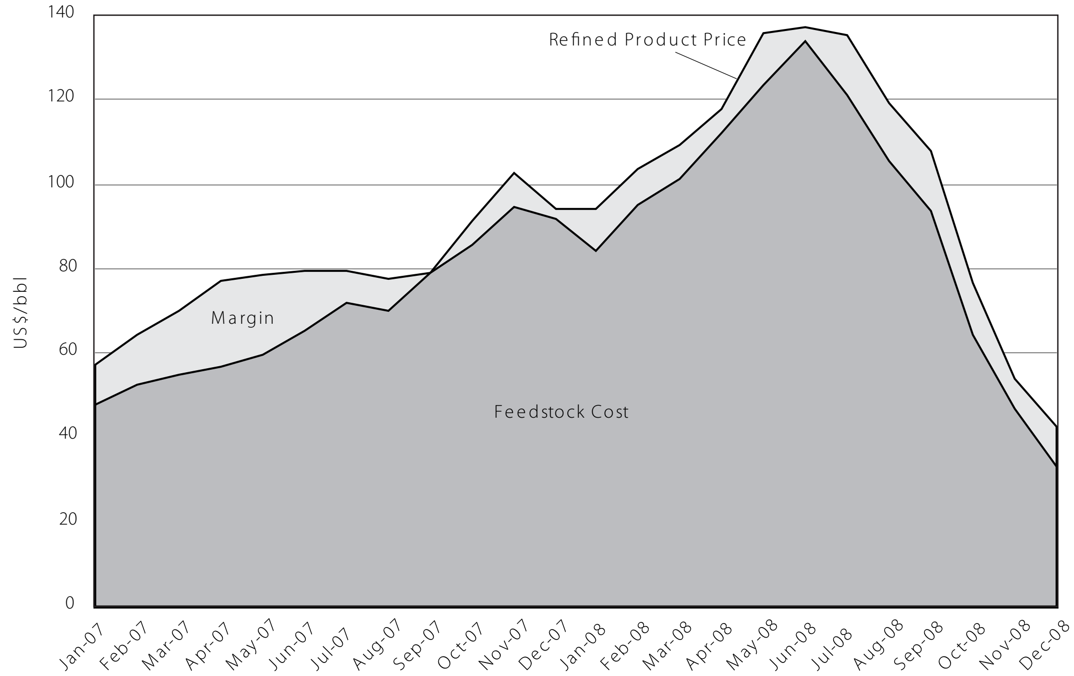
	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**4,092,555**	**670,686**	**4,194,595**	2,982,655	504,375	3,098,556
Cost of feedstock for processing and products for resale[1]	**3,804,952**	**614,201**	**3,850,507**	2,595,907	460,281	2,667,714
Gross margin[2]	**287,603**	**56,485**	**344,088**	386,748	44,094	430,842
Average refining margin (US$/bbl)	**7.16**			10.05		

(1) Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $568.6 million for the year ended December 31, 2008 (2007 - $388.5 million) reflecting the refined products produced by the refinery and sold by the Marketing Division.

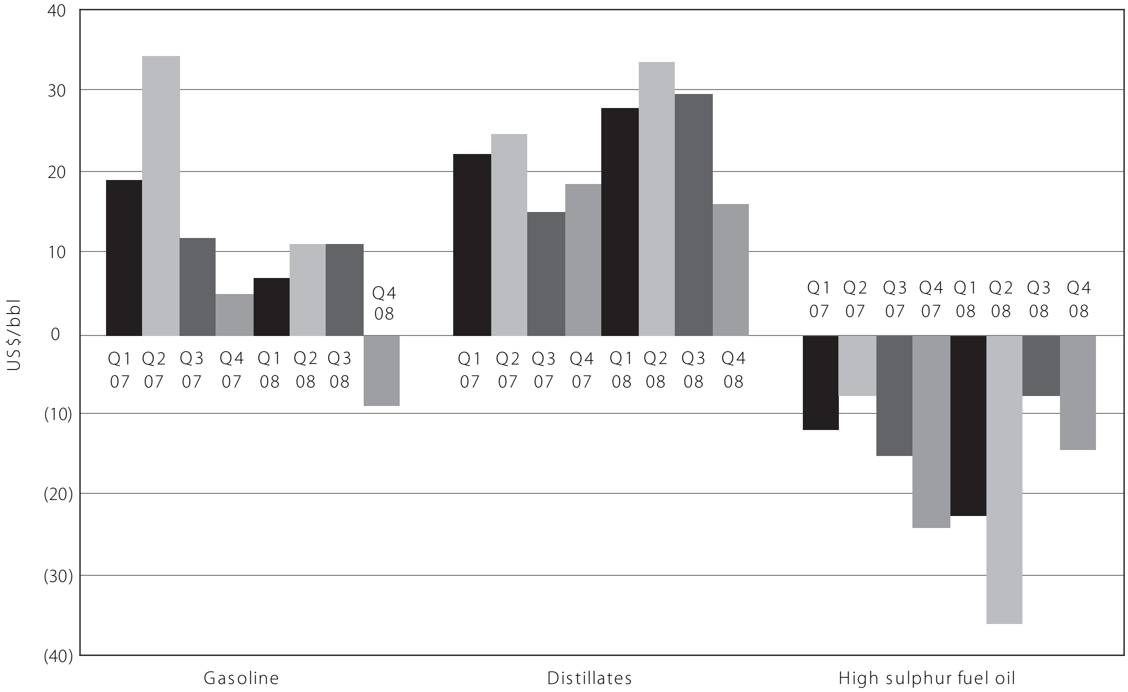
(2) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

Refining Gross Margin

The following graph summarizes our average refining margin relative to the cost of feedstock for the period of January 2007 to December 2008:



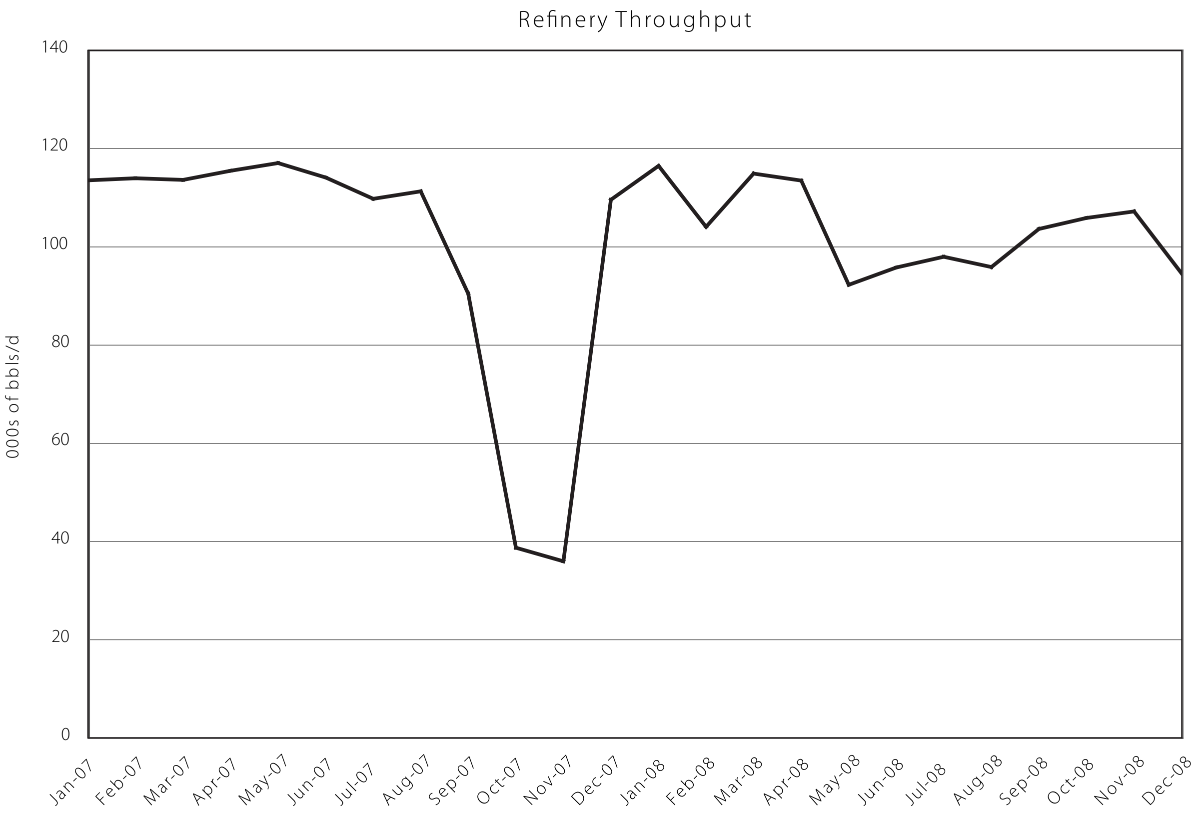
The following chart summarizes our refining margin by refined product over the same time period by quarter:



Crack spreads on gasoline and HSFO peaked during the first half of 2007, resulting in an average refining margin of US$13.69 per bbl with the distillate refining margin averaging US$23.52 per bbl. However, during the second half of 2007 and the first half of 2008 as feedstock costs continued to rise, crack spreads on gasoline and HSFO declined considerably from their peak, and were only partially offset by improved crack spreads on distillate products, which resulted in our average refining margin dropping to US$4.16 per bbl and US$7.36 per bbl for the six month periods ended December 31, 2007 and June 30, 2008, respectively. During the second half of 2008, although feedstock costs decreased significantly, crack spreads on gasoline continued to deteriorate, particularly in the Fourth Quarter when gasoline crack spreads were negative, resulting in an average refining margin of US$6.95 per bbl.

Refinery Throughput

The throughput of our refinery for the period of January 2007 to December 2008 is illustrated below in thousands of barrels of feedstock per day:



During 2008, our feedstock was comprised of 93,697 bbl/d of medium sour crude oil and 9,800 bbl/d of vacuum gas oil ("VGO") as compared to 87,060 bbl/d of crude oil and 11,557 bbl/d of VGO in the prior year. Our aggregate total throughput in 2008 was 103,497 bbls/d, a 4,880 bbls/d increase over the prior year reflecting a utilization rate of 90% relative to an 115,000 bbls/d nameplate capacity. While the refinery experienced limited planned or unplanned downtime in 2008, our throughput was intentionally reduced from May through August in an effort to improve overall gross margin by reducing feedstock to eliminate the production of vacuum tower bottoms ("VTB's") in excess of our visbreaker unit capacity, thereby eliminating the need to downgrade middle distillate valued streams to blend the excess VTB's into lower valued HSFO. Throughput during September through December was reduced due to fouling in heat exchangers, including an online partial exchanger cleaning in December. The remaining exchangers will be cleaned during the ISOMAX catalysts replacement planned for April 2009. During the Fourth Quarter of 2007, we completed a turnaround of the crude unit and vacuum tower and positioned the refinery for uninterrupted operations in 2008 except for the visbreaker turnaround in the Fourth Quarter of 2008.

Refinery Sales Revenue

A comparison of our refinery yield, product pricing and revenue for the years ended December 31, 2008 and 2007 is presented below:

	Year Ended December 31					
	2008			2007		
	Refinery Revenues	**Volume**	**Sales Price(1)**	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn $)	**(000s of bbls)**	**(US$ per bbl/ US$ per US gal)**	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**1,327,599**	**12,830**	**97.58/2.32**	1,088,215	11,726	86.77/2.07
Distillates	**2,006,406**	**15,661**	**120.81/2.88**	1,339,388	14,245	87.91/2.09
High sulphur fuel oil	**758,550**	**9,651**	**74.12**	555,052	9,740	53.28
	4,092,555	**38,142**	**101.18**	2,982,655	35,711	78.09
Inventory adjustment		**(454)**			53	
Total production		**37,688**			35,764	
Yield (as a % of Feedstock)[2]		**100%**			99%	

(1) Average product sales prices are based on the deliveries at our refinery loading facilities.
(2) After adjusting for changes in inventory held for resale.

Our refinery sales revenue is dependent on the selling price of the refined products produced as well as the yield of refined products produced from the crude oil and other feedstocks. Although our yield can be altered slightly by adjusting refinery operations to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed and refinery performance. For the year ended December 31, 2008, our refinery yield was comprised of 32% gasoline products, 42% distillates and 26% HSFO compared to 32%, 40% and 28% for the same products respectively during 2007. The shift in product yield in 2008 from HSFO to distillates is primarily attributed to feedstock selection, process unit optimization and reduced throughput.

Our average sales price for our refined products relative to the average WTI price in the current year was US$4.25/bbl lower than in the prior year. In 2008, our average sales price was US$101.18/bbl (a premium of US$1.53/bbl over WTI) as compared to an average selling price of US$78.09/bbl in the prior year (a premium of US$5.78bbl over WTI) This reduction in premium represents a $171.9 million price variance in 2008.

During 2008, the average sales price of our gasoline products of US$97.58/bbl was a US$2.07/bbl discount to the average WTI price as compared to a US$14.46/bbl premium over WTI realized in 2007 representing a $224.9 million decrease in gross margin as compared to the prior year. This US$16.53 drop in our gasoline refining margin relative to WTI reflects generally weaker demand for gasoline in North America.

During 2008, the average sales price for our distillate products of US$120.81/bbl was a US$21.16/bbl premium over the average WTI price as compared to a US$15.60/bbl premium over WTI realized in 2007 representing a $92.3 million increase in gross margin as compared to the prior year. During 2008, the international demand for distillate products was strong supporting improved distillate margins. During 2008, we received US$7.9 million of incremental revenue from delivering approximately 7.5 million barrels of distillate products to Europe pursuant to our profit sharing arrangement with Vitol.

During 2008, the average sales price of our HSFO of US$74.12/bbl was a US$25.53/bbl discount to average WTI price as compared to a US$19.03/bbl discount in 2007 representing a $66.5 million reduction in gross margin as compared to the prior year. The US$5.56/bbl improvement in our distillate pricing relative to WTI and the shift in product yield from HSFO to distillates was insufficient to fully offset the US$16.53/bbl and US$6.50/bbl margin reductions for gasoline products and HSFO, respectively.

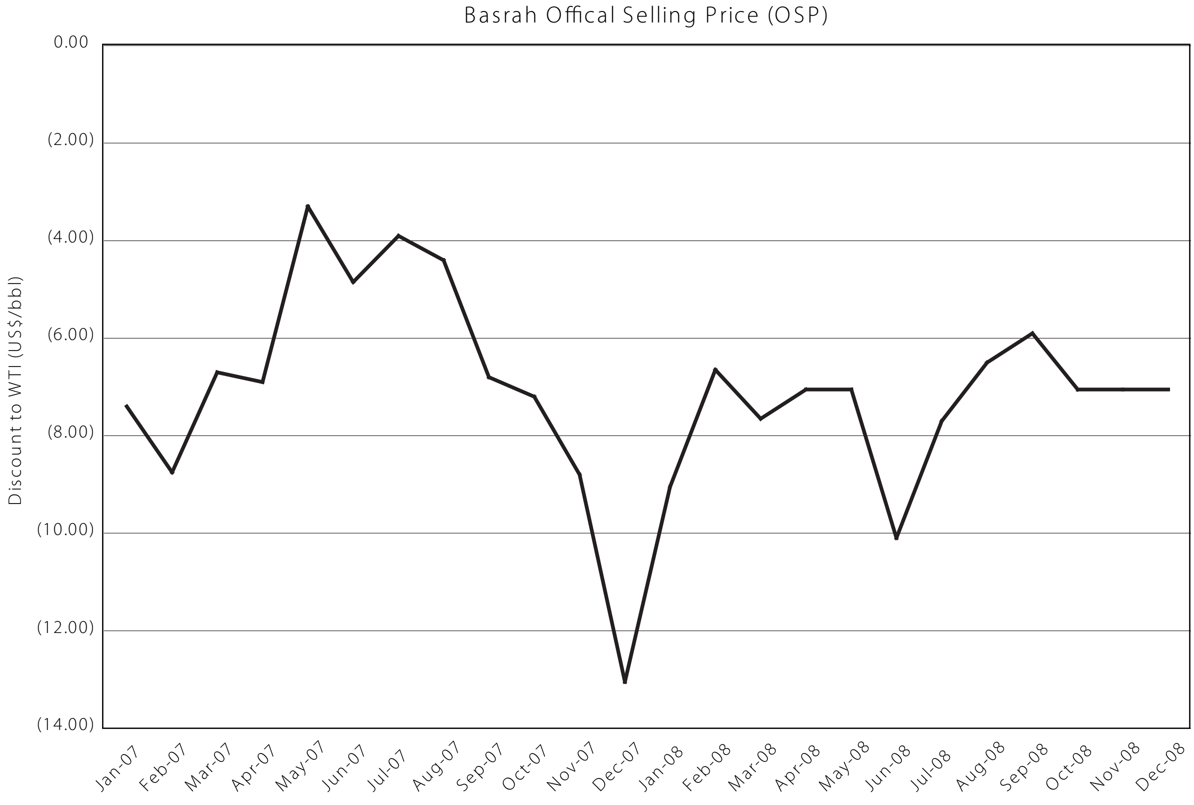
Refinery Feedstock

The volatility of WTI prices throughout 2008 makes it difficult to compare the economics of crude types when our consumption of crude type varies from month to month and costs are aggregated over the year. Further, our refinery competes for international waterborne crude oils and VGOs and the WTI benchmark price generally reflects a land-locked North American price with limited access to the international markets. A comparison of crude oil and VGO feedstock processed for the years ended December 31, 2008 and 2007 is presented below:

	Year Ended December 31					
	2008			2007		
	Cost of Feedstock	**Volume**	**Cost per Barrel[1]**	Cost of Feedstock	Volume	Cost per Barrel[1]
	(000's of Cdn $)	**(000s of bbls)**	**(US$/bbl)**	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**1,963,882**	**21,218**	**87.28**	1,608,356	23,230	64.74
Russian	**614,187**	**5,973**	**96.97**	237,449	3,367	65.94
Venezuelan	**676,777**	**7,102**	**89.86**	362,868	5,180	65.50
Crude Oil Feedstock	**3,254,846**	**34,293**	**89.50**	2,208,673	31,777	64.99
Vacuum Gas Oil	**396,676**	**3,586**	**104.31**	354,858	4,218	78.66
	3,651,522	**37,879**	**90.90**	2,563,531	35,995	66.59
Net inventory adjustment[2]	**(8,990)**			(36,378)		
Additives and blendstocks	**127,136**			68,754		
Inventory write-down[3]	**35,284**			-		
	3,804,952			2,595,907		

(1) Cost of feedstock includes all costs of transporting the crude oil to refinery in Newfoundland.
(2) Inventories are determined using the weighted average cost method.
(3) Inventory write-downs are calculated on a product by product basis using the lower of cost or net realizable value.

Changes to the cost of our feedstock reflect numerous factors beyond changes in WTI price, including the quality of the crude oil processed, the mix of crude oil types, the costs of transporting the crude oil to our refinery, the ten day delay in pricing pursuant to the Supply and Offtake Agreement and for Iraqi crude oil purchased, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. The discount of Iraqi crude oil relative to the WTI benchmark price is influenced by the quality of the crude oil as well as by the demand from other purchasers who may not be North American based. On a monthly basis, the OSP discount is announced as a discount to the WTI benchmark price for North American deliveries. Since our acquisition of North Atlantic in October 2006, the OSP discount has fluctuated from a low of US$3.30 in May 2007 to a high of US$13.05 in December 2007. The following graph illustrates the volatility of the OSP for Basrah Light since January 2007 which, relative to our US$7.16 average refining margin for 2008, is a significant factor to our downstream financial performance:



Although the OSP discount may change between the date of loading in Iraq and its consumption a few months later at our refinery, the OSP discount applicable at the time of loading does not change for our purchase. For example, the OSP discount of US$7.05 in April 2008 was a component of the cost of our feedstock processed in June and July recognizing the 30 to 45 days required to load in Iraq, in transit time and unloading at our refinery. While we are able to "operationally hedge" the WTI component of our feedstock costs between the date we purchase crude oil and our processing of the crude oil we are not able to hedge or otherwise manage the basis risk associated with the medium sour crude oils we typically process.

The cost of our crude oil feedstock averaged US$89.50/bbl during 2008 representing a US$10.15/bbl discount from WTI as compared to a cost of US$64.99/bbl and a discount of US$7.32/bbl in the prior year. While the increased discount to WTI aggregates to a $102.9 million improved gross margin, the year-over-year US$27.34 increase in the average WTI price added $994.2 million to our crude oil feedstock cost during 2008. The US$89.50/bbl average cost of crude oil feedstock during the year represents a 38% increase over the average cost in the prior year, which impacts Vitol's working capital required and increases our "Time Value of Money" charges paid to Vitol as part of the Supply and Offtake Agreement.

The average cost of purchased VGO during 2008 was US$104.31/bbl representing a premium of US$4.66/bbl relative to the WTI benchmark price as compared to US$78.66/bbl and a US$6.35/bbl premium in the prior year. The higher premium in 2007 is attributed to supply and demand disruptions in that year in the very tightly balanced VGO market. We processed 3.6 million barrels of VGO during the year, as such the US$1.69/bbl lower premium aggregates to a $6.4 million decrease in feedstock costs and a corresponding increase in gross margin compared to 2007.

The benchmark refining crack spreads closely track refining margins if the accounting for feedstock is on a last-in-first-out

("LIFO") basis. Our financial statements account for feedstock on a weighted average cost basis which is in accordance with Canadian generally accepted accounting principles. In a stable commodity price environment, weighted average cost and LIFO accounting results should not be significantly different from market benchmarks and individual refinery results. In a rapidly declining commodity price environment, such as the Fourth Quarter of 2008, the result is that the cost of crude oil feedstock consumed under weighted average cost is higher than on a LIFO basis due to the time lag between crude feedstock purchase and processing. For Harvest, the Supply and Offtake Agreement requires Vitol to hold all crude oil feedstock inventory and substantially all gasoline and distillate inventories and requires Vitol to provide the crude oil feedstock to us at current market prices, resulting in our exposure to falling commodity prices being limited to the inventory we hold, which is primarily work in process material and HSFO inventory. Accordingly, during the Fourth Quarter our refining margins were negatively impacted by write-downs of $35.3 million on our work in progress and HSFO inventories. This write-down is relatively modest compared to the $319.7 million in inventory and in transit commitment held by Vitol to operate our refinery at December 31, 2008, which was a decrease of $540.2 million from the $859.9 million held by Vitol on September 30, 2008.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the years ended December 31, 2008 and 2007:

	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Operating expense	78,907	19,829	98,736	83,935	18,541	102,476
Turnaround and catalyst	5,645	-	5,645	34,486	-	34,486
Purchased energy	131,878	-	131,878	92,328	-	92,328
	216,430	19,829	236,259	210,749	18,541	229,290

The largest component of refining operating expense is wages, salaries and benefits which totaled $49.6 million during 2008 (2007 - $51.3 million) while the other significant components were maintenance and repair costs of $13.2 million (2007 - $11.9 million), insurance of $5.7 million (2007 - $6.6 million) and professional services of $5.1 million (2007 - $5.7 million) Refining operating expenses were $2.08/bbl during the year as compared to $2.33/bbl in 2007 reflecting increased throughput and a reduction in total refining operating expenses. The marketing division's operating expenses have increased by $1.3 million primarily due to scheduled tug boat maintenance in June 2008.

Turnaround and catalyst expenditures of $5.6 million (2007 - $34.5 million) relate to planned equipment certifications scheduled during the shutdown to implement the visbreaker unit project modifications.

Purchased energy, consisting of low sulphur fuel oil and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the year ended December 31, 2008 was $3.48/bbl of throughput as compared to $2.57/bbl for 2007. In 2008, we purchased approximately 1,599,000 barrels of fuel oil at an average price of US$72.79/bbl as compared to approximately 1,398,000 barrels purchased in 2007 at an average price of US$55.68/bbl. The $39.6 million increase in the cost of purchased fuel oil is due to a $27.3 million increased price variance and an $11.9 million increase in volume consumed. Our electricity costs remained substantially unchanged during the year at $9.9 million as compared to $9.6 million in the prior year.

Marketing Expense and Other

During the year ended December 31, 2008, marketing expense was comprised of $3.4 million (2007 - $3.4 million) of marketing fees (based on US$0.08/bbl) to acquire feedstock and $26.0 million (2007 - $31.6 million) of "Time Value of Money" charges both pursuant to the terms of the Supply and Offtake Agreement. The decreased "Time Value of Money" charge is mainly the result of a lower LIBOR rate in 2008 which was partially offset by a larger crude oil inventory investment due to the higher commodity prices. In the Fourth Quarter of 2008, marketing expense and other includes $8.7 million in one time accrual reversals related to prior periods. As at December 31, 2008, Harvest had commitments totaling approximately $319.7 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the year ended December 31, 2008 totaled $56.2 million (2007 - $44.1 million) The largest component of our 2008 downstream capital program relates to the expansion and improvement of our visbreaker. The total costs associated with this project were $32.2 million of which approximately $30.1 million was incurred in 2008; the project was completed in mid-November. The increased capacity will upgrade approximately 1,500 bbls/d of HSFO into middle distillate valued streams.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the years ended December 31, 2008 and 2007:

	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**62,383**	**2,555**	**64,938**	64,251	2,071	66,322
Intangible assets	**4,749**	**1,389**	**6,138**	4,781	1,497	6,278
	67,132	**3,944**	**71,076**	69,032	3,568	72,600

The process units are amortized over an average useful life of 20 to 30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows respectively.

Goodwill

At December 31, 2008, we had $216.2 million of goodwill on our balance sheet related to the October 2006 acquisition of our downstream business segment. As our downstream assets are held in a self-sustaining subsidiary with a U.S. dollar functional currency, our goodwill is adjusted at each balance sheet date to reflect the period end foreign exchange rate. We assess our goodwill for impairment on an annual basis unless events or changes in circumstances warrant more frequent testing. To assess goodwill for potential impairment we compare the estimated fair value of the business segment at the balance sheet date to the recorded net book value. If the estimated fair value exceeds the net book value, no further evaluation is required. Management uses judgment in determining the estimated fair value using internal assumptions and external information to compute the present value of expected future cash flows using discount rates commensurate with the risks involved.

Our fair value estimate at December 31, 2008 assumes the completion of $300 million of planned debottlenecking projects and the related throughput, yield, and energy efficiency improvements. Estimated future refining margins were based on forward curve pricing at December 31, 2008 for the first two years of our projection and were assumed to be constant for subsequent years. Our selected discount rate is based on the long-term risk-free interest rate at December 31, 2008 and adjusted for an appropriate credit spread based on estimated current capital market expectations. We calculated the expected future cash flows for each of the next five years in our fair value model and have computed a terminal value to reflect cash flows to be earned in the years thereafter. At December 31, 2008, the estimated fair value of our downstream business segment exceeded its carrying value, and accordingly, no goodwill impairment was identified.

Related Party Transactions

During the year ended December 31, 2008, Vitol purchased $320.9 million (2007 - $354.8 million) of crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. On December 21, 2008, the director disposed the interest in the company and as such, subsequent to this date, this company no longer represents a related party.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Harvest employs an integrated approach to cash flow risk management strategies whereby the our cash flow from producing crude oil in western Canada is financially integrated with our requirement to purchase crude oil feedstock for our Downstream operations even though the crude oil produced in western Canada does not physically flow to our refinery in Newfoundland. As a result, our 2009 cash flow at risk is comprised of approximately 33,000 bbls/d of refined product price exposure, 82,000 bbls/d of refined product crack spread exposure and 84,000 mcf/d of western Canadian natural gas price exposure.

Our cash flow risk management program includes a detailed analysis of the impact of changes in crude oil prices, natural gas prices, the U.S./Canadian dollar exchange rate and certain refined product prices. While the strong commodity prices experienced throughout the first three quarters of 2008 resulted in record operating cash flow from our upstream operations, they also resulted in $225.2 million of realized losses on our price risk management contracts. As commodity prices declined in the Fourth Quarter of 2008, we realized $24.4 million of gains on our risk management contracts. The table below provides a summary of the gains and losses realized on our price risk management contracts for the years ended December 31, 2008 and 2007:

	Year Ended December 31		
(000s)	**2008**	2007	Change
Crude oil	**$ (36,625)**	$ (41,462)	(12%)
Refined product	**(174,129)**	-	n/a
Natural gas	**(381)**	6,299	(106%)
Currency exchange rates	**401**	5,725	(93%)
Electric Power	**9,952**	3,147	216%
Total	**$(200,782)**	$ (26,291)	664%

During 2008, our net realized loss on price risk management contracts increased to $200.8 million, primarily due to the losses on our refined product pricing contracts of $174.1 million, as lower settlements on crude oil and increased gains on electric power contracts were substantially offset by lower gains on our currency exchange and natural gas contracts.

With respect to our crude oil production, we had pricing contracts in place for 10,000 bbl/d during the first half of 2008 at an average price of US$60.00/bbl with 73% participation on prices above US$60.00. We had a further 6,000 bbl/d contracted during the second half of 2008, which capped the WTI price at US$87.53 and provided a floor of US$62.00. As WTI averaged US$99.65 in 2008, cash settlements on these crude oil contracts aggregated to $36.6 million, with losses of $41.2 million during the first three quarters, offset by gains of $4.6 million in the Fourth Quarter.

In respect of refined products, we had pricing contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil throughout 2008. The cash settlements of these contracts aggregated to $128.0 million and $49.3 million, respectively, during the year. In addition, we had contracts in place on 6,000 bbl/d of NYMEX heating oil crack spread, which were settled with cash payments of $12.9 million; 2,000 bbl/d of Platts heavy fuel oil crack spread, which settled with cash received by Harvest of $5.1 million; and 6,000 bbl/d of NYMEX RBOB gasoline crack spread, which were settled with cash received by Harvest of $10.9 million during the year. In total, during the first three quarters of 2008, we realized losses on our refined product contracts totaling $195.7 million, offset by gains of $21.6 million in the Fourth Quarter.

With respect to currency exchange rates, we had contracted to fix the exchange rate during the first six months of 2008 on US$8.3 million per month averaging Cdn$1.11 per US $1.00 and throughout 2008 we had an exchange rate collar in place that collared an exchange rate of Cdn$1.00 to Cdn$1.055 per US$1.00 on a further US$10 million per month. The settlements on the fixed rate contract resulted in $5.2 million received by Harvest during the first six months of 2008 while the exchange rate collar settled with payments of $4.8 million by Harvest.

During 2008, the settlement of our fixed price power contracts for 35 MWh at $56.69 per MWh resulted in $10.0 million received by Harvest as the Alberta electric power prices averaged $89.95 per MWh during the period. The fixed price contract ended in December 2008.

As of December 31, 2008, the mark-to-market value on our refined product contracts was $36.1 million, while the mark-to-market deficiency on our natural gas contracts was $0.2 million. We had no contracts for WTI, currency exchange rate and electrical power at the end of December 2008. Further details on our financial instruments and risk management contracts are included in Note 20 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

As of December 31, 2008, we had risk management contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil from January 2009 through June 2009 and a negligible amount of natural gas contracts through to the end of 2009. These contracts are more fully described in the "Outlook" section of this MD&A.

Interest Expense

	Year Ended December 31		
(000s)	**2008**	2007	Change
Interest on short term debt			
Bank loan	**$ -**	$ 1,275	(100%)
Convertible Debentures	**295**	2,498	(88%)
Amortization of deferred finance charges – short term debt	**-**	1,811	(100%)
	295	5,584	(95%)
Interest on long-term debt			
Bank loan	**51,855**	70,204	(26%)
Convertible Debentures	**69,159**	56,740	22%
$7^7/_8$% Senior Notes	**22,662**	22,561	0%
Amortization of deferred finance charges – long term debt	**2,699**	2,696	0%
	146,375	152,201	(4%)
Total interest expense	**$ 146,670**	$ 157,785	(7%)

Interest expense, including the amortization of related financing costs, decreased $11.1 million (7%) compared to the prior year as interest on our bank borrowings has decreased by $19.6 million due to lower borrowing costs, while total interest expense on Convertible Debentures has increased as a result of our 2008 Convertible Debenture offering.

The interest on our $1.6 billion Extendible Revolving Credit Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings. During the year, interest charges on bank loans reflected an effective interest rate of

4.12%. Further details on our credit facilities are included under "Liquidity and Capital Resources" and Note 10 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

The interest on our Convertible Debentures totaled $69.5 million during 2008, representing a $10.2 million increase over the prior year. The increase is due to the April 25th issuance of $250 million face value of 7.5% Convertible Debentures due 2015. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. Interest on the Convertible Debentures is based on the effective yield of the debt component of the Convertible Debentures, and as a result, the interest expense recorded is greater than the cash interest paid.

The interest on our 7⅞% Senior Notes totaled $22.7 million for the year ended December 31, 2008. Similar to our Convertible Debentures, interest expense is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid.

Included in short and long term interest expense is the amortization of the discount on the 7⅞% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit facility, all totaling $2.7 million for the year ended December 31, 2008.

Currency Exchange

Currency exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated 7⅞% Senior Notes as well as any other U.S. dollar cash balances. Realized foreign exchange losses of $19.1 million for 2008, have resulted from the settlement of U.S. dollar denominated transactions. In 2007 we refinanced our U.S. dollar denominated bank loans with Canadian bank borrowings, realizing a foreign exchange gain of $47.1 million in respect of this loan. Since December 31, 2007, the Canadian dollar has weakened compared to the U.S dollar from near parity to a rate of 1.218 at December 31, 2008, resulting in a year-to-date unrealized foreign exchange loss of $11.7 million. Of this unrealized loss, $55.4 million relates to the 7⅞% Senior Notes, offset by $43.9 million of unrealized foreign exchange gains attributed to downstream transactions.

Our downstream operations are considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by our downstream operations relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars. The cumulative translation adjustment recognized in other comprehensive income represents the translation of our downstream operation's U.S. dollar functional currency financial statements to Canadian dollars using the current rate method. During 2008, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $284.7 million net cumulative translation gain (2007 – net loss of $243.6 million) as the stronger U.S. dollar results in an increase in the relative value of the net assets in our downstream operations.

Future Income Tax

Following the enactment of Bill C-52 in June 2007, we recorded a $177.7 million future income tax charge in our Second Quarter 2007 results reflecting the taxing of the temporary differences between the book value and tax basis of assets held by our Mutual Fund Trust and our other "flow through" entities. The principal source of temporary differences for our corporate entities is in respect of our property, plant and equipment and the recognition for accounting purposes of the mark-to-market value of our price risk management contracts while for our Mutual Fund Trust and other "flow through" entities, the temporary differences arise due to our net profits royalty interests. With respect to the future income tax provision for our Mutual Fund Trust and other "flow through" entities, the provision is based on the expected temporary differences and applicable income tax rates as at January 1, 2011 when the impact of Bill C-52 becomes effective and this provision will change to reflect changes in estimates of the temporary differences and legislated changes to income tax rates to be in effect on January 1, 2011.

During 2008, we recorded a $108.6 million future income tax charge reflecting the net impact of the exempt income earned by our "flow through" entities and a significant change to our estimate of the expected temporary differences of our "flow through" entities on January 1, 2011. Currently, income earned by our "flow through" entities in respect of net profits royalty interests and interest on inter-entity debt between our operating entities and our Mutual Fund Trust is exempt from income taxes as income tax liability is transferred to our Unitholders with the payment of distributions.

At the end of 2008, we had a net future income tax provision on our balance sheet of $204.0 million comprised of a $372.6 million future liability provision for our Mutual Fund Trust and other "flow through" entities and an offsetting future income tax asset of $168.6 million for our corporate entities as compared to a net future income tax provision of $86.6 million comprised of a $270.5 million provision and a $183.9 million net asset at the end of the prior year.

At the end of 2008, we estimated our unclaimed capital expenditures to be:

Tax Classification (in millions)	Trust	Upstream Operations	Downstream Operations	Total
Canadian Oil & Gas Property Expenditures	$ 514.9	$ 377.9	$ -	$ 892.8
Canadian Development & Exploration Expenditures	-	309.8	-	309.8
Unclaimed Capital Costs	-	465.0	380.0	845.0
Non-capital losses and other	28.9	778.4	272.4	1,079.7
Total	$ 543.8	$ 1,931.1	$ 652.4	$ 3,127.3

Income Tax Reassessment

In January 2009, the Canada Revenue Agency ("CRA") issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted taxable income to include the net profits interest revenue to an accrual basis whereas our income tax filings have been prepared on a cash basis. Management and our legal advisors believe the reassessment by the CRA has not properly applied a provision of the Income Tax Act (Canada) that entitles income from a property to be included in taxable income in the year in which the payment is received. In addition to presenting the merit of our position to the CRA, we have filed a Notice of Objection with the CRA and expect that the matter will be referred to a judicial proceeding.

In 2005, the Harvest Energy Trust tax return was prepared on a cash basis with no taxes payable and if prepared on an accrual basis of reporting consistent with the 2002 through 2004 taxation years as reassessed by the CRA, there would be taxes owing of approximately $40 million. In 2006, the Harvest Energy Trust tax return was prepared using an accrual basis of reporting for the Net Profits Interest payments and included the incremental payments required to align the prior years' cash basis of reporting with no taxes payable.

As both management and our legal advisors believe the Income Tax Act (Canada) entitles income from a property to be reported on a cash basis prior to 2007, we expect the outcome of the CRA reassessments will be resolved with no taxes paid for taxation years 2002 through 2006. Accordingly, the amount of this contingent liability has not been accrued for the year ended December 31, 2008.

Update on the Taxation of Royalty Trusts

Following the October 31, 2006 announcement to apply a tax to the distributions from certain publicly traded mutual fund trusts, the Government of Canada introduced Bill C-52 and Bill C-28 to implement the changes. On June 22, 2007, Bill C-52 was enacted which implemented the proposals to tax publicly traded mutual fund trusts and as a result, we recorded a $177.7 million future income tax net charge in our Second Quarter 2007 results reflecting the taxing of the temporary differences between the book value and the tax basis of our assets held by our Mutual Fund Trust and our other "flow through" entities. On December 14, 2007, Bill C-28 was enacted to implement reductions in the federal corporate income tax rates from 20.5% to 19.5% in 2008 with further reductions scheduled resulting in a 15% rate as of January 1, 2012 and we adjusted our future income tax provisions accordingly.

During 2008, the Government of Canada introduced legislation to adjust the deemed provincial tax rate component for the tax on distributions from publicly traded mutual fund trusts to reflect the provincial allocation of business activity as well as legislation to enable income trusts and royalty trusts to convert to publicly traded corporations without adverse Canadian income tax consequences and also accelerated the normal growth guideline contained in Bill C-52. However, neither of these proposed legislative changes became law due to federal elections and the proroguing of Parliament deferring the process.

We continue to review and evaluate the impact of the enacted changes as well as the proposed changes and while there has been no decision at this time, we are more likely to convert to a corporation while retaining the income tax advantages until 2011.

Contractual Obligations and Commitments

We have contractual obligations and commitments entered into in the normal course of operations including the purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

	Maturity				
Annual Contractual Obligations (000s)	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	**$1,530,728**	$ -	$ 1,530,728	$ -	$ -
Interest on long-term debt(4)	**104,781**	52,612	52,169	-	-
Interest on Convertible Debentures(3)	**325,818**	65,269	127,864	105,386	27,299
Operating and premise leases	**24,348**	7,868	13,074	2,840	566
Purchase commitments(5)	**36,537**	36,537	-	-	-
Asset retirement obligations(6)	**1,203,785**	14,214	30,790	26,958	1,131,823
Transportation (7)	**6,679**	2,744	3,202	733	-
Pension contributions(8)	**43,526**	6,900	14,217	14,791	7,618
Feedstock commitments	**319,746**	319,746	-	-	-
Total	**$3,595,948**	$ 505,890	$ 1,772,044	$ 150,708	$ 1,167,306

(1) As at December 31, 2008, we have entered into financial contracts for downstream production of refined products with average deliveries of approximately 20,000 bbl/d for the first half of 2009.

(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Trust Units at our option.

(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. At the Trust's option the interest on Convertible Debentures can be settled in Trust Units.

(4) Assumes constant foreign exchange rate.

(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.

(6) Represents the undiscounted obligation by period.

(7) Relates to firm transportation commitment on the Nova pipeline.

(8) Relates to the expected contributions for employee benefit plans.

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

Off Balance Sheet Arrangements

As at December 31, 2008 and December 31, 2007, we have no off balance sheet arrangements in place.

Change In Accounting Policies

Effective January 1, 2008, we have adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") Section 3862 Financial Instruments – Disclosures, Section 3863 Financial Instruments – Presentation, and Section 1535 Capital Disclosures. The additional disclosures required as a result of adopting these new standards can be found in the notes to our consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

In June 2007, the CICA issued Section 3031 – Inventories, which replaces the existing standard for inventories. This standard provides additional disclosure requirements for inventories, and requires that inventories be valued at the lower of cost and net realizable value. The standard was effective for Harvest on January 1, 2008. Application of this standard did not have a material impact on our financial statements.

DISTRIBUTIONS TO UNITHOLDERS

We declare monthly distributions to Unitholders in light of our expectations of cash from operating activities and capital expenditure plans as well as debt repayment requirements. We typically declare monthly distributions for the quarter and with a longer term view of the commodity price environment, use our balance sheet to provide a stable stream of distributions from a business operating in a commodity price environment that may be volatile from time to time. Our distributions will generally exceed the net income reported in our financial statements as a result of significant non-cash charges recorded in our income statement which have no impact on cash from operating activities. Our net income will fluctuate significantly from our cash flow from operating activities.

The following table summarizes our cash from operating activities, net income (loss), distributions declared and proceeds from our distribution reinvestment programs as well as distributions as percentage of cash from operating activities for the past two years:

	Year Ended December 31		
(000s except per trust unit amounts)	**2008**	2007	Change
Cash from Operating Activities	$ 655,877	$ 641,313	2%
Net Income (Loss)	$ 212,019	$ (25,676)	926%
Distributions declared	$ 551,325	$ 610,280	(10%)
Per trust unit	$ 3.60	$ 4.40	(18%)
Distribution reinvestment proceeds	$ 137,974	$ 178,489	(23%)
Distributions as a percentage of cash from operating activities	84%	95%	(11%)

In 2008, our distributions exceeded our net income by $339.3 million with non-cash charges of $519.8 million for depletion, depreciation, amortization and accretion ("DDA&A"), a $108.6 million charge in respect of future income tax expense and an $11.7 of unrealized currency exchange losses offset by $185.9 million of unrealized gains on price risk management contracts. Our provision of $519.8 million in respect of DDA&A is based primarily on a unit-of-production amortization of our historic costs of property, plant and equipment and does not accurately represent the fair value or replacement cost of the assets. During 2007, our distributions to Unitholders exceeded our loss by $636.0 million with non-cash charges of $526.7 million for depletion and depreciation, $147.8 million in respect of unrealized price risk management contracts and a $65.8 million of future income provision somewhat offset by $55.7 million of unrealized currency exchange gains. During 2008, distributions declared represented 84% of cash from operating activities as compared to 95% in the prior year, both of which are in excess of our 55% to 80% annual target.

As we declare distributions, management, together with the Board of Directors, assess the level of our monthly distributions in light of commodity price expectations, currency exchange rates, upstream production and downstream throughput projections, operating cost forecasts, debt leverage and spending plans. On November 12, 2008 with the WTI benchmark price trading at approximately US$60.00, we declared a $0.30 distribution for the next four months to be paid on December 15, 2008, January 15, 2009, February 17, 2009 and March 16, 2009. Subsequent to this declaration, the severity of the global economic slowdown and drop in commodity prices exceeded expectations and as a result, the distributions declared in the Fourth Quarter of 2008 represent approximately 141% of our cash from operating activities before adjustment for non-cash working capital and asset retirement expenditures. With capital spending of $107.3 million in the Fourth Quarter of 2008, we have relied on other sources to fund distributions and with expectations of approximately $120 million of capital spending in the First Quarter of 2009, we will likely be relying on other sources to fund a significant portion of our distributions in the First Quarter of 2009.

After having maintained a monthly distribution of at least $0.30 from February 2006 through March 2009, we have declared a $0.05 per Trust Unit distribution for Unitholders of record on March 23, 2009 and payable on April 15, 2009 due to the challenging economic conditions; low commodity prices, capital expenditures in the First Quarter of 2009 and balance sheet liquidity. This measure is part of a business strategy to direct substantially all of our future cash flow to a combination of capital expenditures to maintain our productive capacity and improve our liquidity by reducing bank borrowings. As a result of the ongoing turmoil in global credit markets, there is also a heightened need to focus on renewing/extending our Extendible Revolving Credit Facility maturing in April 2010 under which we are currently borrowing approximately $1,250 million. We expect that with a lower level of bank borrowing, the renewal/extension of our credit facility should be less strained. Currently, debt covenants in our credit facility agreement and 7⅞Senior Note indenture that could limit our distributions are not expected to restrict distributions in the foreseeable future.

Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan

We have a Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP") that entitles eligible Unitholders to direct their distributions to the purchase of additional Trust Units at 95% of the average market price, as defined in the DRIP. Alternatively, eligible Unitholders may elect under the premium distribution plan to have their distributions invested in new Trust Units and exchanged through the DRIP broker for a premium distribution equal to 102% of the amount that the Unitholder would otherwise have received, subject to proration and withholding tax reductions in certain circumstances. Only Canadian resident Unitholders are eligible to participate in the premium distribution plan at this time.

During 2008, Unitholders elected to direct $138.0 million of distributions to either the distribution reinvestment plan or the premium distribution plan resulting in the issuance of 7,655,414 Trust Units as compared to $178.5 million and 6,809,987 Trust Units in the prior year. The optional trust unit purchase plan was not used in either 2008 or 2007.

LIQUIDITY AND CAPITAL RESOURCES

Harvest is an integrated energy trust with a declining asset base in our upstream operations and a "near perpetual" asset in our downstream operations. As well as future petroleum and natural gas prices, our upstream operations rely on the successful exploitation of our existing reserves, future development activities and strategic acquisitions to replace existing production and add additional reserves. With a prudent maintenance program, our downstream assets are expected to have a long life with additional growth in profitability available by upgrading the HSFO currently produced, enhancing our refining capability to handle a lower cost feedstock and/or expanding our refining throughput capacity. Future development activities and modest acquisitions in our upstream business as well as the maintenance program in our downstream business will likely be funded by our cash flow from operating activities while we will generally rely on funding more significant acquisitions and growth initiatives from some combination of cash flow from operating activities, issuances of Trust Units and incremental debt. To the extent that we finance acquisitions and growth initiatives from cash flow from operating activities, the amount of our distributions to Unitholders may be reduced. Should equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to Unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs and accordingly, maintenance capital is not disclosed separately.

During 2008, global economic conditions changed significantly from an expectation of strong economic growth in the first half of the year to a more broadly based credit crunch with a tightening of capital availability and higher borrowing costs during the second half of the year. As global economic conditions changed so did commodity prices with the NYMEX futures for WTI priced at US$100 per barrel in January, climbing to an all-time record of US$147 in July and then falling to approximately US$40 by the end of the year as significant economies fell into recession and the growth in developing economies slowed sharply. This has resulted in a significant reduction in the trading value of our Trust Units and has resulted in our access to capital markets becoming more difficult. These conditions have also significantly impacted our cash flow from operating activities as well as opportunities to improve our balance sheet leverage.

During 2008, cash flow from operating activities was $655.9 million including the $9.9 million increase in non-cash working capital. We declared distributions of $551.3 million ($413.3 million net of our distribution re-investment plans), required $327.5 million for capital expenditures and a further $128.8 million for our acquisition and disposition activity resulting in a net cash requirement of $213.7 million. At the end of 2008, our bank borrowings totaled $1,226.2 million, a reduction of $53.3 million over the prior year as the $239.5 million of net proceeds from the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures in April more than offset the net cash requirement from capital investing and distributions to Unitholders in excess of cash provided by operating activities.

For the year ended December 31, 2007, cash flow from operating activities was $641.3 million after providing $17.4 million for an increased investment in non-cash working capital with distributions to Unitholders of $610.3 million declared ($431.8 million net of Unitholder participation in our distribution re-investment plans) and $482.9 million of capital expenditures and acquisitions (net of divestitures) resulting in a net cash requirement of $273.4 million. With net proceeds of $576.0 million from the issuance of $230 million of principal amount of 7.25% Convertible Unsecured Subordinated Debentures and 13,449,250 Trust Units, drawing under our credit facilities were reduced by $302.6 million during 2007.

During the Fourth Quarter of 2008, cash flow from operating activities was $183.7 million, including an additional $89.0 million provided by a reduction in non-cash working capital. Cash flow from operating activities before changes in non-cash working capital totaled $94.8 million as compared to $71.4 million in the Fourth Quarter of 2007. After declaring distributions of $140.6 million (a $109.2 million cash requirement after Unitholder participation in our distribution reinvestment plans) and $107.3 million for capital expenditures, the net cash requirement of $32.8 million was funded by an increase in bank borrowings.

During 2008, the principal change in our capital structure was our issuance in April of $250 million principal amount of 7.5% Convertible Debentures Due 2015 with the net proceeds of $239.5 million. With lesser impact, we elected to settle the maturity of $24.3 million principal amount of 10.5% Convertible Debentures on January 31, 2008 with the issuance of 1,116,593 Trust Units rather than settling the obligation with cash and during 2008, we issued 7,655,414 Trust Units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $138.0 million.

The following table summarizes our capital structure as at December 31, 2008 and 2007:

	As At December 31	
(in millions)	**2008**	2007
DEBT		
Extendible Revolving Credit Facility	**$1,226.2**	$1,279.5
7⅞ % Senior Notes Due 2011 (US$250 million)(1)	**304.5**	247.8
Convertible Debentures, at principal amount(2)	**916.7**	691.2
Total Debt	**2,447.4**	2,218.5
Unitholders' Equity, at book value less equity component of convertible debentures		
157,200,701 issued at December 31, 2008	**2,559.2**	
148,291,170 issued at December 31, 2007		2,445.8
TOTAL CAPITALIZATION	**$5,006.6**	$4,664.3

(1) Face value converted at the period end exchange rate.
(2) See Note 12 of the Consolidated Financial Statements for the years ended December 31, 2008 and 2007 filed on SEDAR at www.sedar.com.

At the end of 2008, we had $373.8 million of unutilized borrowing capacity under our $1.6 billion Extendible Revolving Credit Facility. This syndicated covenant-based secured facility matures in April 2010 unless extended, which would require each lender to consent with respect to their individual commitments. In light of the credit crunch, we deferred requesting an extension in 2008 as some lenders may have chosen to not extend and extending lenders would have likely required increased fees and credit spreads, as well as a reduced level of commitment. At December 31, 2008, our secured debt to annualized EBITDA was 1.5 to 1.0, total debt (excluding convertible debentures) to annualized EBITDA was 1.8 to 1.0, while the secured debt to total capitalization was 25% and total debt (excluding convertible debentures) to total capitalization was 31%. For a complete description of our covenant-based credit agreement, see Note 10 to our audited consolidated financial statements for the year ended December 31, 2008 and our credit agreement filed on SEDAR at www.sedar.com.

Our cash flow risk management program includes our entering into numerous pricing contracts. We have limited our counterparties to the lenders in our Extendible Revolving Credit Facility as the security provided in our credit agreement extends to our pricing contracts and this eliminates the requirement for margin calls and the pledging of collateral as well as limits the negotiation of events of default, all of which contribute to ensuring that these contracts improve our liquidity rather than exacerbate credit concerns.

In October 2004, Harvest Operations Corp., a wholly-owned subsidiary of Harvest, issued US$250 million of principal amount 7⅞% Senior Notes and they remain outstanding at December 31, 2008. These 7⅞% Senior Notes are unsecured, require semi-annual payments of interest and mature on October 15, 2011. The most restrictive covenant of the 7⅞% Senior Notes limits the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1.0 and in respect of the incurrence of secured indebtedness, limits the amount to less than 65% of the present value of future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10%. At the end 2008, 65% of the present value of the future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10% is approximately $1.9 billion.

Our 7⅞% Senior Notes are rated by both Standard and Poor's Ratings Services ("S&P") and Moody's Investors Service ('Moody's") who have assigned a corporate rating of "B" and "B3", respectively, and have rated the 7⅞% Senior Notes as "CCC+" and "Caa1", respectively. These ratings reflect Harvest's relatively high financial leverage and inability to fund meaningful growth (or debt reduction) from internal cash flows while maintaining a significant level of distributions to Unitholders. Recently, S&P have revised its ratings outlook from stable to negative reflecting an expectation of lower upstream production and weakened financial metrics as a result of low hydrocarbon prices. In 2007, Moody's had also cautioned that their stable outlook assumes that commodity prices and refining margins remain supportive and that the leverage is reduced before market conditions soften.

At the end of 2008, we had $916.7 million of principal amount of Convertible Debentures issued in seven series with $39.6 million of principal amount due prior to the end of 2011 and $877.1 million of principal amount due beyond 2011. As the conversion price of the outstanding Convertible Debentures ranges from $13.85 to $46.00, we do not expect a significant amount of conversion activity until the trading value of our Trust Units appreciates from its current trading range. The most restrictive term of the Convertible Debentures limits the issuance of additional Convertible Debentures if the principal amount of all issued and outstanding Convertible Debentures immediately after the issuance exceed 25% of the total market capitalization, being an aggregate of the principal amount of all issued and outstanding Convertible Debentures plus an amount equal to the current market price of all of the issued and outstanding Trust Units. At December 31, 2008, our total market capitalization was approximately $2.6 billion which would limit the issuance of any further Convertible Debentures.

During 2008, the trading value of our Trust Units ranged from a high of $26.00 in February to a low of $8.33 in October. During October, the volume of units traded and drop in trading price is generally attributed to the precipitous drop in crude oil and natural gas prices to a level that will likely result in abnormally low cash flows and the deterioration of business fundamentals beyond the normal cyclical fluctuations. The following summarizes the trading value of our Trust Units during 2008 and the first two months of 2009:

	Trading Price		
Month	**High**	**Low**	**Volume**
Canadian Trading			
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	26.00	22.49	8,552,342
March 2008	24.13	22.00	9,638,750
April 2008	24.94	22.23	11,965,637
May 2008	25.67	22.15	14,019,461
June 2008	25.77	23.32	9,263,955
July 2008	24.60	19.32	10,210,064
August 2008	21.75	18.90	12,078,183
September 2008	21.12	15.89	9,834,707
October 2008	17.69	8.33	26,521,040
November 2008	14.09	10.65	14,381,812
December 2008	12.68	9.42	11,179,958
January 2009	11.91	10.36	10,266,136
February 2009	10.57	5.87	13,739,710
U.S. Trading (in US$)			
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	25.70	22.51	15,108,961
March 2008	24.49	21.44	17,099,323
April 2008	24.82	22.06	20,845,245
May 2008	26.08	21.75	24,871,749
June 2008	25.28	23.05	16,892,369
July 2008	24.30	18.80	23,625,243
August 2008	20.55	17.73	17,597,112
September 2008	20.01	15.17	24,126,064
October 2008	16.69	7.00	65,647,621
November 2008	11.55	8.60	37,694,288
December 2008	10.17	7.26	31,705,600
January 2009	10.10	8.25	25,461,464
February 2009	8.55	4.69	36,881,966

We are authorized to issue an unlimited number of Trust Units and at the end of 2008, approximately 71% of our Unitholders were non-residents of Canada which is relatively unchanged from 66% at the end of 2007. As of February 28, 2009, we had 159,240,909 Trust Units outstanding, 7,995,016 of Unit Appreciation Rights granted (of which 2,032,922 were vested) and 649,357 awards issued under the Unit Awards Incentive Plan (of which 273,771 were vested)

On October 20, 2008, we announced that the Toronto Stock Exchange had accepted our intention to commence a Normal Course Issuer Bid to purchase for cancellation at prevailing market prices up to 14,826,261 Trust Units as well as up to $91.4 million principal amount of Convertible Debentures. To date, we have not purchased any securities pursuant to this Normal Course Issuer Bid.

We have entered into a Supply and Offtake Agreement with Vitol, an international crude oil trader, that initially required the ownership of the crude oil feedstock and substantially all of the refined product inventory at the refinery be retained by Vitol and granted Vitol the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase substantially all refined products produced by the refinery. This arrangement provides Harvest with financial support for its crude oil purchase commitments as well as working capital financing for its inventories of crude oil and substantially all refined products held for sale. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. Currently, the Supply and Offtake Agreement may be terminated by either Vitol or Harvest with six months prior notice. Pursuant to the Supply and Offtake Agreement, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) valued at approximately $319.7 million at the end of 2008 which would have otherwise have been assets of Harvest as compared to $843.6 million at the end of 2007.

As provided for in the Supply and Offtake Agreement and effective January 20, 2008, we entered into an independent fuel oil offtake arrangement with a wholly-owned affiliate of one of the world's largest integrated energy companies for the sale of all of our HSFO production for a period of one year with a one year renewal option requiring mutual consent. This arrangement required that we provide financing for our inventories of HSFO which at December 31, 2008 totaled $6.7 million.

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

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31						
	2008			2007			
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total	Change
Revenues	**238,550**	**690,152**	**928,702**	308,022	624,512	932,534	0%
Royalties	**(35,963)**	**-**	**(35,963)**	(53,410)	-	(53,410)	(33%)
Net revenues	**202,587**	**690,152**	**892,739**	254,612	624,512	879,124	2%
Less:							
Purchased product for resale and processing	**-**	**629,994**	**629,994**	-	579,766	579,766	9%
Operating expenses	**82,161**	**53,395**	**135,556**	76,100	81,271	157,371	(14%)
Transportation and marketing	**3,258**	**(5,805)**	**(2,547)**	2,347	7,895	10,242	(125%)
Cash G&A	**8,299**	**440**	**8,739**	7,844	441	8,285	5%
Unit based compensation expense	**(2,197)**	**(79)**	**(2,276)**	(3,553)	48	(3,505)	(35%)
Total G&A	**6,102**	**361**	**6,463**	4,291	489	4,780	35%
Depreciation, depletion and accretion	**119,339**	**20,638**	**139,977**	115,176	17,746	132,922	5%
Net income per segment	**(8,273)**	**(8,431)**	**(16,704)**	56,698	(62,654)	(5,957)	180%
Realized gains (losses) on risk management contracts			**24,434**			(17,375)	(241%)
Unrealized gains (losses) on risk management contracts			**192,252**			(122,739)	(257%)
Interest and other financing charges			**(37,324)**			(36,959)	1%
Currency exchange (loss) gain			**(8,510)**			10,856	(178%)
Large corporation tax and other tax			**552**			1,059	(48%)
Future income tax (expense) recovery			**(76,060)**			57,530	(232%)
Net income (loss)			**78,640**			(113,585)	(169%)
Per Trust Unit, basic			**0.50**			(0.77)	(165%)
Per Trust Unit, diluted			**0.50**			(0.77)	(165%)
Cash From Operating Activities			**183,740**			87,998	109%
Per Trust Unit, basic			**1.18**			0.60	97%
Per Trust Unit, diluted			**1.10**			0.60	83%
Distributions declared			**140,646**			144,681	(3%)
Distributions declared, per Trust Unit			**0.90**			0.98	(8%)
Distributions declared as a percentage of Cash From Operations			**77%**			164%	(87%)
UPSTREAM OPERATIONS							
Daily Production							
Light / medium oil (bbl/d)			**25,088**			26,640	(6%)
Heavy oil (bbl/d)			**11,306**			13,354	(15%)
Natural gas liquids (bbl/d)			**2,770**			2,595	7%
Natural gas (mcf/d)			**96,079**			94,961	1%
Total daily sales volume (boe/d)			**55,177**			58,416	(6%)
Operating Netback(1) ($/BOE)							
Revenue			**46.99**			57.32	(18%)
Royalties			**(7.08)**			(9.94)	(29%)
Operating expense			**(16.19)**			(14.16)	14%
Transportation expense			**(0.64)**			(0.44)	45%
Operating Netback(1)			**23.08**			32.78	(30%)
Cash capital expenditures			**82,975**			30,643	171%
DOWNSTREAM OPERATIONS							
Average daily throughput (bbl/d)			**102,500**			61,717	66%
Aggregate throughput (mbbl)			**9,430**			5,678	66%
Average Refining Margin (US$/bbl)			**3.93**			6.00	(35%)
Cash capital expenditures			**24,317**			16,889	44%

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

During the Fourth Quarter of 2008, cash from operating activities totaled $183.7 million, a $95.7 million increase as compared to $88.0 million in the prior year. The increase is primarily due to an $89.0 million reduction in working capital as compared to a $16.6 million reduction in the prior year and $24.4 million in realized gains on risk management contracts as compared to realized losses of $17.4 million in the prior year. Cash generated from our upstream operations of $108.9 million, reflects a decrease of $59.3 million as compared to $168.2 million in the prior year, primarily due to a 30% decrease in operating netbacks and a 6% decrease in production volumes. Cash generated from our downstream operations increased to $10.6 million during the Fourth Quarter of 2008, as compared to a $44.9 million cash deficiency in the prior year, reflecting the impact of the planned turnarounds in 2007, partially offset by lower refining margins in the current period.

Upstream Operations

Our 2008 Fourth Quarter revenues decreased $69.5 million compared to the prior year as a result of our realized commodity prices decreasing by $10.33/boe (18%) due to lower crude oil prices and a decrease in production volumes of 3,239 boe/d as compared to the prior period due to normal decline and a reduction in 2008 capital spending. Light/medium oil sales revenue for the three month period ended December 31, 2008 was $53.3 million (31%) lower than in same period in the prior year due to an unfavourable price variance of $43.2 million and an unfavourable volume variance of $10.1 million. Heavy oil revenues for the three months ended December 31, 2008 decreased by $15.9 million (26%) due to an unfavourable price variance of $6.7 million and an unfavourable volume variance of $9.2 million. Natural gas sales revenue increased by $5.3 million (9%) for the three months ended December 31, 2008 over the same period in 2007, which reflects a favourable price variance of $4.6 million and a favourable volume variance of $0.7 million.

For the three months ended December 31, 2008, our net royalties as a percentage of revenue were 15.1% ($36.0 million) as compared to 17.3% ($53.4 million) in the same period in 2007. Our royalty rate for the Fourth Quarter of 2008 was lower than in the same period in 2007, due to favourable one-time credits received during the period.

Operating expenses increased by $6.1 million (8%) for the three months ended December 31, 2008 as compared to the same period in the prior year, which reflects a $5.7 million increase in power and fuel costs, comprised primarily of electric power costs. The average Alberta electric power price of $95.17/MWh in the Fourth Quarter of 2008 was 54% higher than the average price of $61.76/MWh in the same period in 2007.

Transportation and marketing expense increased by $0.9 million to $3.3 million for the three months ended December 31, 2008, due to increased clean oil trucking costs associated with the two acquisitions completed in the Third Quarter of 2008.

For the three months ended December 31, 2008, cash G&A increased by $0.5 million (6%) compared to the same period in the prior year reflecting increased costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry.

Capital spending in the Fourth Quarter of 2008 increased by $52.3 million to $83.0 million as compared to the prior year. The increase in spending is primarily due to increased drilling activity as we drilled 82 wells (48.0 net) in the Fourth Quarter of 2008 as compared to drilling 21 wells (10.0 net) in the Fourth Quarter of 2007.

Downstream Operations

Our 2008 Fourth Quarter gross margin increased by $15.4 million to $60.2 million as compared to $44.8 million in the same period in the prior year, reflecting increased throughput offset by lower refining margins. In the Fourth Quarter of 2008, refinery throughput averaged 102,500 bbl/d compared to 61,717 bbl/d in the prior year reflecting the impact of planned turnarounds in 2007. However, throughput was below the refinery's nameplate capacity of 115,000 bbls/d in the Fourth Quarter of 2008 due to our managing the fouling in heat exchangers, including an online partial exchanger cleaning in December. While throughput increased, our 2008 Fourth Quarter average refining margin decreased by US$2.07/bbl to US$3.93/bbl from US$6.00/bbl in the Fourth Quarter of 2007 reflecting negative gasoline crack spreads in the Fourth Quarter of 2008 and a $35.3 million write-down on inventories, which were partially offset by increased discounts relative to the WTI benchmark on our feedstock costs.

The cost of feedstock was US$48.34/bbl in the Fourth Quarter, a decrease of US$43.76/bbl compared to the prior year due to the significant quarter over quarter decrease in WTI.

Operating costs averaged $2.00/bbl of throughput for the Fourth Quarter of 2008 as compared to $3.61/bbl in the same period in the prior year. The decrease is due to turnaround activity in the prior year reducing throughput.

Capital spending increased by $7.4 million to $24.3 million in the Fourth Quarter of 2008 as compared the prior year due to spending $13.7 million to complete of our visbreaker project in November 2008.

Corporate

Interest expense increased by $0.4 million for the three months ended December 31, 2008 relative to the same period in the prior year. The increase is attributed to a $5.6 million increase in interest expense on our Convertible Debentures, with the issuance of $250 million of principle amount of 7.5% Convertible Debentures in April; a $1.2 million increase in interest expense on our U.S. dollar Senior notes, due to the strengthening of the U.S. dollar; offset by a $6.4 million decrease in interest expense on our bank borrowings, due to lower interest rates.

In the Fourth Quarter of 2008, we realized a $24.4 million gain and a $192.3 million unrealized gain on our risk management contracts as compared to a realized loss of $17.4 million and a $122.7 million unrealized loss in the same period in 2007. The realized and unrealized gains in the Fourth Quarter of 2008 is due the significant decrease in commodity prices in the period.

In the Fourth Quarter of 2008, we realized an $11.8 million loss on currency exchange transactions and an unrealized $3.3 million gain on currency translation, as compared to a $4.7 million realized gain and a $6.2 million unrealized gain in the same period in 2007. The realized losses in the Fourth Quarter of 2008 are primarily the result of our downstream operations settling trade payables as the Canadian dollar weakened, which accounted for $8.1 million of the total $11.8 million realized loss. The unrealized gain in the Fourth Quarter of 2008 relates to an increase in the net assets of our downstream operation on translation to Canadian dollars, offset by an increase in the value of our U.S. dollar denominated Senior Notes.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our Fourth Quarter of 2008 relative to the preceding seven quarters:

	2008				2007			
(000s except where noted)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenue, net of royalties	**$ 892,739**	**$ 1,597,195**	**$ 1,622,079**	**$ 1,377,352**	$ 879,124	$ 1,031,514	$ 1,133,450	$ 1,025,512
Net income (loss)	**$ 78,640**	**$ 295,788**	**$ (162,063)**	**$ (346)**	$ (113,585)	$ 11,811	$ 6,248	$ 69,850
Per Trust Unit, basic[1]	**$ 0.50**	**$ 1.93**	**$ (1.07)**	**$ -**	$ (0.77)	$ 0.08	$ 0.05	$ 0.55
Per Trust Unit, diluted[1]	**$ 0.50**	**$ 1.73**	**$ (1.07)**	**$ -**	$ (0.77)	$ 0.08	$ 0.05	$ 0.55
Cash from operating activities	**$ 183,740**	**$ 133,493**	**$ 210,534**	**$ 128,119**	$ 87,998	$ 191,049	$ 251,218	$ 111,048
Per Trust Unit, basic	**$ 1.18**	**$ 0.87**	**$ 1.39**	**$ 0.85**	$ 0.60	$ 1.31	$ 1.88	$ 0.87
Per Trust Unit, diluted	**$ 1.10**	**$ 0.84**	**$ 0.83**	**$ 0.83**	$ 0.60	$ 1.22	$ 1.67	$ 0.84
Distributions per Unit, declared	**$ 0.90**	**$ 0.90**	**$ 0.90**	**$ 0.90**	$ 0.98	$ 1.14	$ 1.14	$ 1.14
Total long-term financial debt	**$ 2,352,196**	**$ 2,284,664**	**$ 2,105,998**	**$ 2,209,451**	$ 2,172,417	$ 2,097,187	$ 1,987,352	$ 2,436,018
Total assets	**$ 5,745,407**	**$ 5,659,227**	**$ 5,637,879**	**$ 5,574,528**	$ 5,451,683	$ 5,585,651	$ 5,613,333	$ 5,800,346

(1) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.

Net revenues are comprised of revenues net of royalties from our upstream operations as well as sales of refined products from our downstream operations. Revenues throughout 2007 remained relatively stable until the Fourth Quarter of 2007 when the refinery throughput decreased due to a planned shutdown for more than half the quarter. Throughout the first three quarters of 2008, net revenues have been the highest in Harvest's history due to strong commodity prices; however the significant decrease in commodity prices in the Fourth Quarter of 2008 resulted in a significant decrease in net revenues.

The growth in cash from operating activities is closely aligned with the trend in commodity prices for our upstream operations, reflects the cyclical nature of the downstream segment, and is significantly impacted by changes in working capital. In the Fourth Quarter of 2008, cash from operating activities has increased from the previous quarter reflecting decreased working capital requirements in our downstream business, partially offset by a $37.30/boe decrease in our upstream operating netback and a $6.54/bbl decrease in refining margins, both due to the decrease in the demand for commodities as the economy slowed.

Net income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains on risk management contracts and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a $177.7 million future income tax expense in the quarter. In the Fourth Quarter of 2007 Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts, resulting in a $57.5 million future income tax recovery in the quarter. In the First Quarter of 2008, future income tax recovery of $21.8 million was recorded as a result of the reversal of temporary timing differences between depreciation recorded over the amount of tax pool claims; an additional recovery of $95.2 million was recorded in the Second Quarter of 2008; an expense of $149.5 million was recorded in the Third Quarter of 2008; and an expense of $76.1 million was recorded in the Fourth Quarter. Changes in the fair value of our risk management contracts have also contributed to the volatility in net income (loss) over the preceding eight quarters. For these reasons, our net income (loss) does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Total assets over the last eight quarters have remained relatively stable. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. Total long term financial liabilities have also remained relatively stable over the last eight quarters, reflecting moderate acquisition activity, offset by the issuance of Trust Units in the First and Second Quarters of 2007, and a net cash surplus of cash from operating activities over distributions to Unitholders.

OUTLOOK

We anticipate that 2009 will be a challenging year with the global economic slowdown and financial crisis continuing to limit liquidity in the financial markets and causing reduction in demand for commodities including gasoline and distillate products in North America and Europe. These factors will impact our performance and we have taken action to minimize the impact with sizable reductions to our capital spending plans and a “belt tightening” of expenses. In light of reduced availability of liquidity/credit and significantly reduced cash flow with lower commodity prices, we intend to be responsible and disciplined in our approach to capital expenditures to maintain our productive capacity and reduce debt.

For our upstream operations, our original capital spending plan approved spending of $250 million including the Enhanced Oil Recovery (“EOR”) projects identified in late 2007 focusing on reservoir management. In early 2009, we revised our upstream spending plan to $170 million including $110 million in the First Quarter of the year. We are continuing most of the drilling program scheduled for the First Quarter as a large percentage of the program is at Hay River where the projects remain attractive at current prices and the area is only accessible in the winter months. There are a few wells planned for southeast Saskatchewan and Cheddarville for the First Quarter of 2009 that will proceed while substantially all other drilling activity planned has been curtailed. As commodity prices continued to weaken in late 2008 and early 2009, we have re-focused our spending on projects that remain economically viable with a shift to light to medium oil prospects.

During the last three quarters of 2009, our drilling commitments will continue to be subjected to a rigorous evaluation reflecting the current commodity price outlook as well as considering the impact of costs which are expected to soften following spring break-up. However, spending on our EOR projects will continue in our larger oil reservoirs at Hay River, Bellshill Lake, Wainwright and Suffield with planned spending of $20 million. We expect our EOR projects to reduce decline rates for an extended period with improved recoveries due to maintaining reservoir pressures and the bolstering of traditional water flood projects with the introduction of chemical enhancements, such as alkaline surfactant polymers. Our continued focus on reservoir management and reduced drilling activity will likely result in a relatively stable production profile throughout 2009 with the front-end loaded Hay River production providing a “step change” to our Second Quarter production as compared to the Fourth Quarter of 2008.

We anticipate that our upstream production will average approximately 35,000 bbls/d of liquids and 90,000 mcf/d of natural gas (approximately 50,000 boe/d), with a strong Second Quarter reflecting the drilling results from Hay River. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 53% of our total production in 2009 with heavy oil and natural gas accounting for 19% and 28%, respectively. We will continue to focus on operating costs and G&A costs and pursue opportunities to reduce costs given the less active investment environment. For 2009, we are projecting our operating costs to be approximately $15.50 per boe as compared to $14.70 per boe in 2008, an increase of $0.80 per boe primarily due to reduced production volumes. We anticipate general and administrative costs to be approximately $1.50 per boe.

In our downstream operations, our capital spending will be directed to maintenance activities and incremental discretionary investments to improve reliability, increase throughput, enhance margins and reduce operating costs. While initial spending plans totaled $62 million, our revised plan of $50 million for 2009 includes predominately turnaround and reliability projects. We are now anticipating a 35-day shutdown of the hydrocracker unit for refurbishing and catalyst replacement during April, including a 21-day shutdown of the entire refinery, at a planned cost of $45 million with the expected benefit of improved distillate yields and a 1,000 bbls/d increase to the hydrocracker unit capacity. As a result of reduced cash flow, we will continue to evaluate discretionary investments at a measured pace such that we will be positioned to advance these enhancement projects quickly when the commodity price environment and credit/capital markets improve. The $2 billion refinery expansion project discussed in 2008, while still an attractive growth initiative in the appropriate economic climate, has been deferred with no further capital committed.

For 2009, we anticipate that the refinery's daily throughput will average approximately 106,000 bbl/d of feedstock with a refined product yield of 45% distillates, 29% gasoline and 26% HSFO reflecting an increased yield of distillates of approximately 1,500 bbl/d with the completion of the visbreaker expansion project in the Fourth Quarter of 2008. Similar to the Fourth Quarter of 2008, during the First Quarter of 2009 our crude oil and hydrocracker rates will continue to be limited by fouled exchangers and end of life catalyst, and both of these issues will be addressed during the planned April shutdowns. We expect that operating costs and purchased energy costs will aggregate to $5.75 per bbl of throughput with a currency exchange rate of US$0.80 per Canadian dollar. The cash flow contribution from our marketing activities in the Province of Newfoundland and Labrador is expected to add approximately $24 million of incremental cash flow to the downstream operations.

As discussed in the Cash Flow Risk Management section of this MD&A, we have entered into refined product pricing contracts that represent approximately 68% of our WTI price exposure and 18% of our refined product crack spread exposure during the first half of 2008. The heating oil price contracts provides downside protection on the price of 12,000 bbl/d to market prices plus US$13.93 per bbl when prices are lower than US$72.59 and provides a price of US$86.52 when the market price is between US$72.59 and US$86.52 with our upside participation limited to US$98.73 per bbl. Similarly, on the price of 8,000 bbl/d of fuel oil, we have price protection equivalent to market prices plus US$7.63 per bbl when prices are lower than US$49.75 and provide a price of US$57.38 when the market price is between US$49.75 and US$57.38 with our upside participation limited to US$65.89 per bbl. Beyond June 30, 2009, we have no price risk management contracts in place.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our 7⅞% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our Extendible Revolving Credit Facility, which had a balance of $1,226.2 million at December 31, 2008, requires interest payments based on floating rates and accordingly, approximately 50% of our interest rate exposure is floating. Currently, our most significant exposure to increasing interest rates is through the renewal/extension of our credit facilities or the issuance of additional longer term financings as the credit spreads have increased substantially since our most recent renewal or issuance.

Our most pressing financial issues are the renewal of our credit facility with a syndicate of fourteen banks, including Canada's six largest chartered banks, followed by the maturity of the 7⅞% Senior Notes on October 15, 2011. Currently, we have $373.8 million of undrawn capacity and in the First Quarter of 2009, the drawn portion is likely to increase by approximately $150 million. We anticipate that in light of the tightened credit markets, the significant slowdown in the global economy and current commodity prices, the renewal of our credit facility may result in more onerous terms. Although lenders are currently committed to our existing credit facility until its maturity, we will likely renew credit commitments with many of our lenders in advance of the maturity date to extend the term of our available credit beyond April 2010 which may result in an increase in the credit spreads on our borrowings as well as a commitment fee. With respect to the maturity of the 7⅞% Senior Notes in 2011, we intend to create capacity in our credit facilities to enable the repayment of this obligation should alternative sources of debt and/or equity be unavailable.

At the beginning of 2009, we have $916.7 million principle amount of Convertible Debentures issued in seven series with a weighted average interest rate of approximately 7.1%. The terms of our Convertible Debentures require semi-annual payments of interest which may be settled with the issuance 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 the settlement date. In addition, we may elect to satisfy the maturity of these obligations by issuing Trust Units rather than settling the obligations in cash based on the same equivalent price as the settlement of interest obligations. We anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, we will be able to retire the entire principal obligation with equity issuances. Due to an incurrence covenant based on total market capitalization, we are currently restricted from issuing an additional Convertible Debenture. See Note 12 to our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com as well as the Liquidity and Capital Resources section of this MD&A for a full description of the incurrence covenant.

Overall, we expect that based on current commodity price expectations, our 2009 cash from operating activities will be significantly lower than in 2008 and that our capital expenditures and distributions to Unitholders will be constrained with the objective of reducing borrowings under our credit facilities and improving our credit profile. Distributions are approved by our Board of Directors after considering the current and expected economic conditions and in light of the significant reduction in commodity prices, we have declared a distribution of $0.05 per Trust Unit for Unitholders of record on March 23, 2009 and payable on April 15, 2009. In prior years, we have balanced our cash from operating activities and the funding of capital expenditures and distributions with reliance on proceeds from our distribution re-investment programs for shortfalls.

While we do not forecast commodity prices nor refining margins, we have entered into price risk management contracts to mitigate a substantial portion of our price volatility in the first half of 2009, with the objective of stabilizing our 2009 cash flow from operating activities. The following table reflects the sensitivity of our 2009 operations to changes in the following key factors to our business:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 50.00	$ 5.00	$ 0.27 / Unit
CAD/USD exchange rate	$ 0.80	$ 0.05	$ 0.28 / Unit
AECO daily natural gas price	$ 5.00	$ 1.00	$ 0.17 / Unit
Refinery crack spread (US$/bbl)	$ 9.00	$ 1.00	$ 0.24 / Unit
Upstream Operating Expenses (per boe)	$ 15.00	$ 1.00	$ 0.11 / Unit

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties in exchange for Trust Units as well as offer selected properties for divestment to maintain and enhance our productive capability and improve our unit operating costs.

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 they are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

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

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

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

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

Asset Retirement Obligations

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

Impairment of Capital Assets

Numerous estimates and judgments are involved in determining any potential impairment of capital assets. The most significant assumptions in determining future cash flows are future prices and reserves for our upstream operations and expected future refining margins and capital spending plans for our downstream operations.

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

If forecast WTI crude oil prices were to fall by 40%, the initial assessment of impairment of our upstream assets 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. Similarly, for our downstream operations, if forecast refining margins were to fall by more than 15%, it is likely that our downstream assets would experience an impairment despite the expected seasonal volatility in earnings.

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

Goodwill

Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, and must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. Harvest has a goodwill balance for each of our upstream and downstream operations. As at December 31, 2008, we have determined there was no goodwill impairment in either of our reporting units.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2008 (2007 - 0.5%)

Purchase Price Allocations

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

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new section, however do not expect a material impact on our consolidated financial statements.

In December 2008, the CICA issued section 1582, Business Combinations, replacing Section 1581 of the same name. The new Section will be effective on January 1, 2011 with prospective application. Under the new guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, while the current standard requires capitalization as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. While under the current standard only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation.

International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board ("ASB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standard ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end. In mid-2008, the ASB issued an exposure draft to incorporate IFRS into the Canadian accounting standards. In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft proposing amendments for first time adopters of IFRS to enable an entity to measure exploration and evaluation assets at the amount determined under the entity's previous accounting principles and it also provides for the measurement of oil and gas assets in the development or production phase, among other things, by allocating the amount determined by the entity's previous accounting principles to the underlying assets on a pro rata basis using reserve volumes or reserve values at the date of transition. If formally approved by the IASB, these amendments will substantially ease the adoption of IFRS for Harvest. We have determined that our accounting for property, plant and equipment will be impacted as we currently use the full cost method of accounting in accordance with the CICA Accounting Guideline 16: "Oil and Gas Accounting – Full Cost." At this time, the full impact of conversion to IFRS on Harvest's consolidated financial statements is not reasonably determinable.

We have established an IFRS Conversion Plan and have staffed a project team with regular reporting to our senior management team and to the Audit Committee of the Board of Directors. We have completed an initial assessment of the differences between Canadian accounting standards and IFRS and are currently completing a comprehensive assessment of the impact of adopting IFRS on our accounting policies, information technology and data systems, internal control over financial reporting, disclosure controls and procedures, financial reporting expertise as well as business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements.

OPERATIONAL AND OTHER BUSINESS RISKS

Both Harvest's upstream operations and its downstream operations are conducted in the same business environment as most other operators in the respective businesses and the business risks are very similar. However, our structure as a publicly traded mutual fund trust is significantly different than that of a traditional corporation with share capital and there are some unique business risks of our structure. In addition, Harvest's monthly cash distributions limits its accumulation of capital resources from internal sources. We intend to continue executing our business plan to create value for Unitholders by increasing the net asset value per Trust Unit with our risk management activities carried out under policies approved by our Board of Directors.

We have segregated the identification of business risks into those generally applicable to upstream operations as well as downstream operations and those applicable to our royalty trust structure and should be read in conjunction with the full description of these risks in our Annual Information Form for the year ended December 31, 2008 to be filed on www.sedar.com. The following summarizes the more significant risks:

Upstream Operations

- Prices received for petroleum and natural gas have fluctuated widely in recent years and are also impacted by the volatility in the Canadian/US currency exchange rate.
- The differential between light oil and heavy oil compounds the fluctuations in the benchmark oil prices.
- The operation of petroleum and natural gas properties involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected and/or dangerous conditions.
- The production of petroleum and natural gas may involve a significant use of electrical power and since de-regulation of the electric system in Alberta, electrical power prices in Alberta have been volatile.
- The markets for petroleum and natural gas produced in western Canada depend upon available capacity to refine crude oil and process natural gas as well as pipeline capacity to transport the products to consumers.
- The reservoir and recovery information in reserve reports are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.
- Absent capital reinvestment, production levels from petroleum and natural gas properties will decline over time and absent commodity price increases, cash generated from operating these assets will also decline.
- Prices paid for acquisitions are based in part on reserve report estimates and the assumptions made preparing the reserve reports are subject to change as well as geological and engineering uncertainty.
- The operation of petroleum and natural gas properties is subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

Downstream Operations

- The market prices for crude oil and refined products have fluctuated significantly, the direction of the fluctuations may be inversely related and the relative magnitude may be different resulting volatile refining margins.
- The prices for crude oil and refined products are generally based in US dollars while our operating costs are denominated in Canadian dollars which introduces currency exchange rate exposure.
- Crude oil feedstock is delivered to our refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.
- Over 60% of our feedstock in 2008 was supplied from sources in Iraq and if Iraq curtails supply, we may not be able to find another source with an adequate amount of similar type of crude oil.
- We are relying on the creditworthiness of Vitol for our purchase of feedstock and should their creditworthiness deteriorate, crude oil suppliers may restrict the sale of crude oil to Vitol.
- Our refinery is a single train integrated interdependent facility which could experience a major accident, be damaged by sever weather or otherwise be forced to shutdown which may reduce or eliminate our cash flow.

- Our refining operations which include the transportation and storage of a significant amount of crude oil and refined products are adjacent to environmentally sensitive coastal waters, and are subject to hazards and similar risks such as fires, explosions, spills and mechanical failures, any of which may result in personal injury, damage to our property and/or the property of others along with significant other liabilities in connection with a discharge of materials.
- The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft crashes.
- Collective agreements with our employees and the United Steel Workers of America may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.
- Refinery operations are subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

General Business Risks

- The loss of a member to our senior management team and/or key technical operations employee could result in a disruption to either our upstream or downstream operations.
- Our credit facility and other financing agreements contain financial covenants and maturity dates that may limit our ability to sell assets, enter into certain financing arrangements and/or pay distributions to Unitholders.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs and result in less cash available for distributions to Unitholders.
- Our crude oil sales and refining margins are denominated in US dollars while we pay distributions to our Unitholders in Canadian dollars which results in a currency exchange exposure.

Royalty Trust Structural Risks

- Trust Units are hybrid securities in that they share certain attributes common to both equity securities and debt instruments and represent a fractional interest in the Trust.
- Recent changes to income tax legislation related to the royalty trust structure will result in a tax, at the trust level of our structure, on distributions from Harvest at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the Unitholders for income tax purposes.

CHANGES IN REGULATORY ENVIRONMENT

On October 25, 2007, the Government of Alberta released its New Royalty Framework (the "NRF") outlining changes that increase the royalty rates on conventional oil and gas, oil sands and coal bed methane using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. These proposals were given Royal Assent on December 2, 2008 and became effective January 1, 2009. Prior to the NRF, the amount of royalties payable was influenced by the oil price, oil production, density of oil and the vintage of the oil with the rate ranging from 10% to 35% and with respect to natural gas production, the royalty reserved was between 15% to 35% depending on a prescribed or corporate average reference price and subject to various incentive programs.

The NRF sets royalty rates for conventional oil by a single sliding rate formula which is applied monthly and increases the range of royalty rates to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. With respect to natural gas production, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59 per GJ.

The NRF also includes a policy of "shallow rights reversion." The shallow rights reversion policy affects all petroleum and natural gas agreements, however, the timing of the reversion will differ depending on whether the leases and licences were acquired prior to or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence, the policy will apply after the expiry of the intermediate term. Holders of leases and licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The Government intends this policy to maximize the development of currently undeveloped resources by having the mineral rights to shallow gas geological formations that are not being developed revert back to the Government and be made available for resale.

On April 10, 2008, the Government of Alberta introduced two new royalty programs for the development of deep oil and natural gas reserves. A five-year oil program for exploratory wells over 2,000 meters will provide royalty adjustments up to $1 million or 12 months of royalty offsets whichever comes first while a natural gas deep drilling program for wells deeper than 2,500 meters will create a sliding scale of royalty credit according to depth of up to $3,750/meter.

On November 19, 2008, the Government of Alberta announced the introduction of a five year program of Transitional Royalty Plan (the "TRP") which effective January 1, 2009, offers companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 meters) a one-time option, on a well-by-well basis, to reduced royalty rates for new wells for a maximum period of five years to December 31, 2013 after which all wells convert to the NRF. To qualify for this program, wells must be drilled between November 19, 2008 and December 31, 2013.

Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices for conventional oil are less than $53.00, our oil royalties will be lower under the NRF and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling of natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties on most of our wells as they will be considered to be low productivity wells.

For a detailed discussion of our regulatory environment, please refer to the discussion of Industry Conditions in the General Business Description of our Annual Information Form for the year ended December 31, 2008 which will be filed on SEDAR at www.sedar.com

In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas emissions intensity from large emitting facilities. On January 24, 2008, the Government of Alberta announced their plan to reduce projected emissions in the province by 50% under the new climate change plan by 2050. This will result in real reductions of 14% below 2005 levels. The Government of Alberta stated they will form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. On March 10, 2008, the Government of Canada released "Turning the Corner" outlining additional details to implement their April 2007 commitment to cut greenhouse gas emissions by an absolute 20% by 2020. "Turning the Corner" sets out a framework to establish a market price for carbon emissions and sets up a carbon emission trading market to provide incentives for Canadians to reduce their greenhouse gas emissions. In addition, the regulations include new measures for oil sands developers that require an 18% reduction from 2006 levels by 2010 for existing operations and for oil sands operations commencing in 2012, a carbon capture and storage capability. There is no mention of targeting reductions for unintentional fugitive emissions for conventional producers. Companies will be able to choose the most cost effective way to meet their emissions reduction targets from in-house reductions, contributions to time-limited technology funds, domestic emissions trading and the United Nations' Clean Development Mechanism. Companies that have already reduced their greenhouse gas emissions prior to 2006 will have access to a limited one-time credit for early adoption. Giving the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, and the lack of detail in the Government of Canada's announcement, it is not possible to assess the impact of the requirements on our operations and financial performance.

DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision of our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2008 as defined under the rules adopted by the Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2008, our disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to Canadian and U.S. securities authorities was recorded, processed, summarized and reported within the time period specified in Canadian and U.S. securities laws and was accumulated and communicated to Harvest's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining internal control over our financial reporting. Our internal control is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with Canadian Generally Accepted Accounting Principles. Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2008. The evaluation was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management has concluded that as of December 31, 2008, the design and operation of internal controls were effective.

The effectiveness of our internal control over financial reporting as of December 31, 2008 was audited by KPMG, an independent registered public accounting firm, as stated in their report, which is included in our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

During the year ended December 31, 2008, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control systems are met.

ADDITIONAL INFORMATION

Further information about us, including our Annual Information Form, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

MANAGEMENT'S REPORT

In management's opinion, the accompanying consolidated financial statements of Harvest Energy Trust (the "Trust") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to March 2, 2009. Management is responsible for the consistency, therewith, of all other financial and operating data presented in Management's Discussion and Analysis for the year ended December 31, 2008.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

Under the supervision of our Chief Executive Officer and our Chief Financial Officer, we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). We have concluded that as of December 31, 2008, our internal controls over financial reporting were effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The consolidated financial statements and the Trusts' internal control over financial reporting have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Public Accountants Report outlines the scope of their examination and sets forth their opinion on the effectiveness of internal controls over financial reporting.

The Board of Directors is responsible for approving the consolidated financial statements. The Board fulfills its responsibilities related to financial reporting mainly through the Audit Committee. The Audit Committee consists exclusively of independent directors and includes at least one director with financial expertise. The Audit Committee meets regularly with management and the external auditors to discuss reporting and governance issues and ensures each party is discharging its responsibilities. The Audit Committee has reviewed these financial statements with management and the Independent Registered Public Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Trust.

J Zahary

John E. Zahary
President and Chief Executive Officer
Calgary, Alberta
March 2, 2009

R Fotheringham

Robert W. Fotheringham
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust and the Unitholders of Harvest Energy Trust

We have audited Harvest Energy Trust's ("the Trust") internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the years ended December 31, 2008 and 2007, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 2, 2009, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 2, 2009

AUDITORS' REPORT

To the Unitholders of Harvest Energy Trust

We have audited the consolidated balance sheets of Harvest Energy Trust (the "Trust") as at December 31, 2008 and 2007 and the consolidated statements of income (loss) and comprehensive income (loss), unitholders' equity and cash flows for each of the years in the two-year period ended December 31, 2008. 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 and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of 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, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2009 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 2, 2009

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands of Canadian dollars)

	2008	2007
Assets		
Current assets		
Accounts receivable and other	$ 173,341	$ 215,803
Fair value of risk management contracts [Note 20]	36,087	16,442
Prepaid expenses and deposits	11,843	15,144
Inventories [Note 5]	55,788	58,934
	277,059	306,323
Property, plant and equipment [Note 6]	4,468,505	4,197,507
Intangible assets [Note 7]	106,002	95,075
Goodwill [Note 4]	893,841	852,778
	$ 5,745,407	$ 5,451,683
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities [Note 8]	$ 210,097	$ 270,243
Cash distribution payable	47,160	44,487
Current portion of convertible debentures [Note 12]	2,513	24,273
Fair value deficiency of risk management contracts [Note 20]	235	131,020
	260,005	470,023
Bank loan [Note 10]	1,226,228	1,279,501
7⅞% Senior notes [Note 11]	298,210	241,148
Convertible debentures [Note 12]	825,246	627,495
Fair value deficiency of risk management contracts [Note 20]	-	35,095
Asset retirement obligation [Note 9]	277,318	213,529
Employee future benefits [Note 19]	10,551	12,168
Deferred credit	522	710
Future income tax [Note 18]	203,998	86,640
Unitholders' equity		
Unitholders' capital [Note 13, 14]	3,897,653	3,736,080
Equity component of convertible debentures	84,100	39,537
Contributed surplus [Note 15]	6,433	-
Accumulated income	458,884	246,865
Accumulated distributions	(1,891,674)	(1,340,349)
Accumulated other comprehensive income (loss) [Note 3]	87,933	(196,759)
	2,643,329	2,485,374
	$ 5,745,407	$ 5,451,683

Commitments, contingencies and guarantees [Note 22]

Subsequent events [Note 24]

See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

William D. Robertson
Director

Hector J. McFadyen
Director

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31 (thousands of Canadian dollars, except per Trust Unit amounts)

	2008	2007
Revenue		
Petroleum, natural gas, and refined product sales	$ 5,737,809	$ 4,283,013
Royalty expense	(248,445)	(213,413)
	5,489,364	4,069,600
Expenses		
Purchased products for processing and resale	3,850,507	2,667,714
Operating	537,149	530,208
Transportation and marketing	34,243	46,916
General and administrative [Note 17]	34,743	36,328
Realized net losses on risk management contracts	200,782	26,291
Unrealized net losses (gains) on risk management contracts	(185,921)	147,781
Interest and other financing charges on short term debt, net	295	5,584
Interest and other financing charges on long term debt	146,375	152,201
Depletion, depreciation, amortization and accretion	519,811	526,741
Currency exchange loss (gain)	30,882	(109,316)
Large corporations tax and other tax	(81)	(974)
Future income tax expense [Note 18]	108,560	65,802
	5,277,345	4,095,276
Net income (loss) for the year	212,019	(25,676)
Other comprehensive income (loss)		
Cumulative translation adjustment	284,692	(243,632)
Comprehensive income (loss) for the year [Note 3]	$ 496,711	$ (269,308)
Net income (loss) per Trust Unit, basic [Note 14]	$ 1.39	$ (0.19)
Net income (loss) per Trust Unit, diluted [Note 14]	$ 1.39	$ (0.19)

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31 (thousands of Canadian dollars)

	Unitholders' Capital	Equity Component of Convertible Debentures	Contributed Surplus	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive Income (Loss)
At December 31, 2006	$ 3,046,876	$ 36,070	$ -	$ 271,155	$ (730,069)	$ 46,873
Adjustment arising from change in accounting policies	(49)	-	-	1,386	-	-
Issued for cash						
February 1, 2007	143,834	-	-	-	-	-
June 1, 2007	230,029	-		-	-	-
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	250	-	-	-	-	-
8% Debentures Due 2009	513	(4)	-	-	-	-
6.5% Debentures Due 2010	882	(55)	-	-	-	-
10.5% Debentures Due 2008	2,999	(627)	-	-	-	-
6.40% Debentures Due 2012	122	(10)	-	-	-	-
7.25% Debentures Due 2013	244	(8)	-	-	-	-
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	-
Exercise of unit appreciation rights and other	658	-	-	-	-	-
Issue costs	(25,906)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	(243,632)
Net loss	-	-	-	(25,676)	-	-
Distributions and distribution reinvestment plan	178,489	-	-	-	(610,280)	-
At December 31, 2007	**3,736,080**	**39,537**	**-**	**246,865**	**(1,340,349)**	**(196,759)**
Equity component of convertible debenture issuances						
7.5% Debentures Due 2015	-	51,000	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	32	-	-	-	-	-
8% Debentures Due 2009	141	(1)	-	-	-	-
10.5% Debentures Due 2008	13	(3)	-	-	-	-
Redemption of convertible debentures						
10.5% Debentures Due 2008 [Note 12]	24,249	(6,433)	6,433	-	-	-
Exercise of unit appreciation rights and other	1,494	-	-	-	-	-
Issue costs	(2,330)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	284,692
Net income	-	-	-	212,019	-	-
Distributions and distribution reinvestment plan	137,974	-	-	-	(551,325)	-
At December 31, 2008	$ 3,897,653	$ 84,100	$ 6,433	$ 458,884	$ (1,891,674)	$ 87,933

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 (thousands of Canadian dollars)

	2008	2007
Cash provided by (used in)		
Operating Activities		
Net income (loss) for the year	$ 212,019	$ (25,676)
Items not requiring cash		
Depletion, depreciation, amortization and accretion	519,811	526,741
Unrealized currency exchange loss (gain)	11,736	(55,725)
Non-cash interest expense and amortization of finance charges	14,197	12,043
Unrealized loss (gain) on risk management contracts [Note 20]	(185,921)	147,781
Future income tax expense	108,560	65,802
Unit based compensation expense (recovery)	(1,577)	743
Employee benefit obligation	(1,618)	(61)
Other non-cash items	(5)	139
Settlement of asset retirement obligations [Note 9]	(11,418)	(13,090)
Change in non-cash working capital	(9,897)	(17,384)
	655,887	641,313
Financing Activities		
Issue of Trust Units, net of issue costs	-	354,549
Issue of convertible debentures, net of issue costs [Note 12]	239,498	220,488
Bank repayments [Note 10]	(52,413)	(291,947)
Financing costs	(228)	(273)
Cash distributions	(410,678)	(433,699)
Change in non-cash working capital	4,098	(1,223)
	(219,723)	(152,105)
Investing Activities		
Additions to property, plant and equipment	(327,474)	(344,785)
Business acquisitions	(36,756)	(170,782)
Property acquisitions	(138,493)	(27,943)
Property dispositions	46,476	60,569
Change in non-cash working capital	24,274	(14,710)
	(431,973)	(497,651)
Change in cash and cash equivalents	4,191	(8,443)
Effect of exchange rate changes on cash	(4,191)	(1,563)
Cash and cash equivalents, beginning of year	-	10,006
Cash and cash equivalents, end of year	$ -	$ -
Interest paid	$ 115,209	$ 130,990
Large corporation tax and other tax paid	$ (81)	$ 442

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2008 and 2007

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

1. Nature of Operations and Structure of the Trust

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 and is governed pursuant to the Amended and Restated Trust Indenture dated May 20, 2008 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties and refining and marketing assets through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its Trust Units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year. In compliance with the mutual fund trust requirements of the Income Tax Act (Canada), the Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust, including North Atlantic Refining Limited Partnership. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as bank debt and the 7⅞% Senior Notes. The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

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

References to "Harvest" refer to the Trust on a consolidated basis. References to "North Atlantic" refer to Harvest Refining General Partnership and its subsidiaries, all of which are 100% owned by Harvest.

2. Significant Accounting Policies

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("U.S. GAAP") and to the extent that the differences materially affect Harvest, they are described in Note 23.

(a) Consolidation

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

(b) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization and accretion expense, asset retirement obligations, fair value of risk management contracts, employee future benefits and amounts used in the impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future refined product prices, future interest and currency exchange rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) Revenue Recognition

Revenues associated with the sale of crude petroleum, natural gas, natural gas liquids and refined products are recognized when title passes to customers and payment has either been received or collection is reasonably certain. Concurrent with the recognition of revenue from the sale of refined products and included in purchased products for resale and processing are associated transportation charges. Revenues for retail services are recorded when the services are provided.

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum wholesale and retail prices that a wholesaler and a retailer may charge and sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. Prices are set biweekly using a price adjustment formula based on an allowable premium above Platt's with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue as recorded by Harvest.

(d) Inventories

Inventories are carried at the lower of cost or net realizable value. The costs of inventory are determined using the weighted average cost method. The valuation of inventory is reviewed at the end of each month. The costs of parts and supplies inventories are determined under the average cost method.

(e) Joint Interest and Partnership Accounting

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

(f) Property, Plant, and Equipment

Upstream Operations

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

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

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

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

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

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

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test. An impairment of unproved properties is recognized when the cost base exceeds the fair value determined by a reference to market prices, historical experience or a third party independent evaluator. There were no impairment write downs for petroleum and natural gas assets for the years ended December 31, 2008 and 2007.

Downstream Operations

Property, plant and equipment related to the refining assets are recorded at cost. Depreciation of recorded cost less salvage value is provided on a straight-line basis over the estimated useful life of the assets as set out below. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

Asset	Period
Refining and production plant:	
Processing equipment	5 – 25 years
Structures	15 – 20 years
Catalysts	2 – 5 years
Tugs	25 years
Vehicles	2 – 5 years
Office and computer equipment	3 – 5 years

Maintenance and repair costs, including major maintenance activities, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Property, plant and equipment related to refining assets are tested for recovery whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Property, plant and equipment related to refining assets are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If property, plant and equipment related to refining assets are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for refining assets for the years ended December 31, 2008 and 2007.

(g) Goodwill and Other Intangible assets

Goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is carried at cost less impairment and is not amortized. The carrying amount of goodwill is assessed for impairment annually at year-end or more frequently if events occur that could result in an impairment. The goodwill impairment test is a two step test. In the first step, the carrying amount of the assets and liabilities, including goodwill, is compared to the fair value of the reporting unit. The fair value of a reporting unit is determined by calculating the present value of the expected future cash flows from the reporting unit. If the fair value is less than the carrying amount of the reporting unit, a potential impairment of goodwill may exist requiring the second test to be performed. Impairment is measured by allocating the fair value of the reporting unit, as determined in the first test, over the fair value of the identifiable assets and liabilities. The excess of the fair value of the reporting unit over the fair value of the identifiable assets and liabilities represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized as an impairment and charged to income in the period in which it occurs. There were no impairment charges recorded in either of the years ended December 31, 2008 and 2007.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5–20 years. The amortization methods and estimated service lives are reviewed annually. The carrying amounts of intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Intangibles are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If intangibles are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for the years ended December 31, 2008 and 2007.

(h) Asset Retirement Obligations

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

(i) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries are currently subject to income tax. However, pursuant to legislation enacted in 2007, the Trust and its flow-through subsidiaries will become subject to a distribution tax beginning in 2011, provided that Harvest maintains its current structure. Commencing in June 2007, Harvest now provides for future income taxes to reflect this new legislation.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(j) Unit-based Compensation

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

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

(l) Employee Future Benefits

North Atlantic maintains a defined benefit plan and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses.

The cost of providing the defined benefits and other post-retirement benefits is actuarially determined based upon an independent actuarial valuation using management's best estimates of discount rates, rate of return on plan assets, rate of compensation increase, retirement ages of employees, and expected health care costs. The cost of pensions earned by employees is actuarially determined using the projected benefit method prorated on credited service. Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans be made based on independent actuarial valuation. Pension plan assets are measured at fair values with the difference between the fair value of the plan assets and the total employee benefit obligation recorded on the balance sheet. For the purpose of calculating the expected return on assets, the fair value of the plan assets is used.

The defined benefit plans provide benefits based on length of service and the best five years of the last ten years' average earnings. There is no recognition or amortization of actuarial gains or losses less than 10% of the greater of the accrued benefit obligations and the fair value of plan assets for the defined benefit pension plans. Actuarial gains and losses over 10% are amortized on a straight-line basis over the average remaining service period of the plan participants. Actuarial gains or losses related to the other post-retirements benefits are recognized in income immediately. Past service costs are amortized on a straight-line basis over the expected average remaining service life of plan participants.

(m) Currency Translation

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

Harvest's investment in its downstream operations, which is considered a self-sustaining operation with a U.S. dollar denominated functional currency, is translated using the current rate method. Gains and losses resulting from this translation are recorded in the cumulative translation adjustment in accumulated other comprehensive income.

3. Change in Accounting Policy

Financial Instruments and Comprehensive Income

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

Financial Instruments

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

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

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

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

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

See Note 20 for the additional presentation and disclosure requirements for Financial Instruments including those required for 2008 by Sections 3862 and 3863 as issued by the Canadian Institute of Chartered Accountants.

Other Comprehensive Income

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

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

Capital Disclosures

"Capital Disclosures", section 1535, requires the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance.

Inventories

Effective January 1, 2008, Harvest adopted the accounting standard "Inventories", section 3031. This standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. The adoption of this section did not have a material impact on our financial statements.

Future Accounting Changes

In February 2008, the CICA issued section 3064, "Goodwill and Intangible Assets", replacing section 3062 "Goodwill and Other Intangible Assets" and section 3450, "Research and Development Costs". The new section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous section 3062. We do not expect that the adoption of this standard will have a material impact on our consolidated financial statements.

Convergence of Canadian GAAP with International Financial Reporting Standards

In early 2008, Canada's Accounting Standards Board ("AcSB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") beginning January 1, 2011. As Harvest will require a full year of comparative disclosures to be compliant with IFRS, all IFRS accounting policies and procedures will be effective on January 1, 2010. Harvest will be required to report under current Canadian GAAP standards through to December 31, 2010.

4. Acquisitions

(a) Private petroleum and natural gas corporation

On July 24, 2008, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $36.8 million in cash net of working capital adjustments and transaction costs. The purchase price was assigned primarily to oil and gas properties. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date.

(b) Petroleum and natural gas assets

On September 8, 2008, Harvest acquired certain petroleum and natural gas assets in exchange for $130.8 million in cash plus an interest in two non-operated properties for total consideration of $136.3 million. The results of operations of these assets have been included in the consolidated financial statements since the acquisition date.

(c) Grand Petroleum Inc. ("Grand")

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

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

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

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

(d) Private petroleum and natural gas corporation

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

5. Inventories

		December 31, 2008		December 31, 2007
Petroleum products				
Upstream – pipeline fill	**$**	**603**	$	564
Downstream		**50,311**		54,472
		50,914		55,036
Parts and supplies		**4,874**		3,898
Total inventories	**$**	**55,788**	$	58,934

During the year ended December 31, 2008, Harvest recognized $35.3 million (2007 – nil) of inventory impairments in its downstream operations. At December 31, 2008, inventories held at net realizable value totaled $37.6 million (December 31, 2007 – $2.2 million).

6. Property, Plant and Equipment

	December 31, 2008			December 31, 2007		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,710,725**	**$ 1,493,039**	**$ 6,203,764**	$ 4,247,819	$ 1,164,310	$ 5,412,129
Accumulated depletion and depreciation	**(1,572,449)**	**(162,810)**	**(1,735,259)**	(1,142,345)	(72,277)	(1,214,622)
Net book value	**$ 3,138,276**	**$ 1,330,229**	**$ 4,468,505**	$ 3,105,474	$ 1,092,033	$ 4,197,507

General and administrative costs of $10.0 million (2007 – $9.2 million) have been capitalized during the year ended December 31, 2008, of which nil (2007 - $0.6 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

All costs, except those associated with major spare parts inventory and assets under construction, are subject to depletion and depreciation at December 31, 2008 including future development costs of $489.5 million (2007 – $325.4 million). Downstream major parts inventory of $7.5 million were excluded from the asset base subject to depreciation at December 31, 2008 (2007 - $6.1 million). Downstream assets under construction of $12.7 million were excluded from the asset base subject to depreciation at December 31, 2008 (2007 - $7.4 million).

The petroleum and natural gas future prices used in the impairment test for petroleum and natural gas assets were obtained from third party engineers and accepted by management. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying amount of its petroleum and natural gas assets as at December 31, 2008 and 2007, and therefore no impairment was recorded in either of the periods ended on these dates.

Benchmark prices and U.S.$/Cdn.$ exchange rate assumptions reflected in the impairment test as at December 31, 2008 were as follows:

Year	**WTI Oil(1) (US$/barrel)**	**Currency Exchange Rate**	**Edmonton Light Crude Oil(1) (CDN$ barrel)**	**AECO Gas(1) (CDN$/MMBtu)**
2009	60.00	0.85	69.60	7.40
2010	71.40	0.85	83.00	8.00
2011	83.20	0.90	91.40	8.45
2012	90.20	0.95	93.90	8.80
2013	97.40	1.00	96.30	9.05
Thereafter (escalation)	2%	0%	2%	2%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest.

7. Intangible Assets

	December 31, 2008			December 31, 2007		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	$ 108,402	$ (11,969)	$ 96,433	$ 88,227	$ (5,330)	$ 82,897
Marketing contracts	7,539	(2,480)	5,059	6,136	(1,099)	5,037
Customer lists	4,564	(1,008)	3,556	3,714	(449)	3,265
Fair value of office lease	931	(652)	279	931	(428)	503
Financing costs	7,300	(6,625)	675	12,113	(8,740)	3,373
Total	$ 128,736	$ (22,734)	$ 106,002	$ 111,121	$ (16,046)	$ 95,075

8. Accounts Payable and Accrued Liabilities

		December 31, 2008		December 31, 2007
Trade accounts payable	$	61,945	$	100,265
Accrued interest		17,262		15,779
Trust Unit Rights Incentive Plan and Unit Award Incentive Plan [Note 17]		3,894		7,218
Other accrued liabilities		126,996		146,981
Total	$	210,097	$	270,243

9. Asset Retirement Obligation

Harvest's asset retirement obligations result from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $1,203.8 million which will be incurred between 2009 and 2058. The majority of the costs will be incurred between 2015 and 2040. A credit-adjusted risk-free discount rate of 8% - 10% and inflation rate of approximately 2% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

		December 31, 2008		December 31, 2007
Balance, beginning of year	$	213,529	$	202,480
Incurred on acquisition of a private corporation		1,900		1,629
Incurred on acquisition of Grand		-		4,416
Liabilities incurred		4,371		9,553
Revision of estimates		49,395		(6,088)
Net liabilities acquired (settled) through acquisition (disposition)		910		(3,708)
Liabilities settled		(11,418)		(13,090)
Accretion expense		18,631		18,337
Balance, end of year	$	277,318	$	213,529

Harvest has undiscounted asset retirement obligations of approximately $14.9 million relating to the refining and marketing assets. The fair value of this obligation cannot be reasonably determined because the assets currently have an indeterminate life.

10. Bank Loan

Harvest and a syndicate of lenders established a $750 million Three Year Extendible Credit Facility on February 3, 2006 (the "Credit Facility") and on March 31, 2006, completed a secondary syndication and increased the facility to $900 million. Concurrent with the purchase of North Atlantic on October 19, 2006, the facility was further increased to $1.4 billion. During 2007, Harvest and its lenders amended the Credit Facility to increase the aggregate commitment from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010. At December 31, 2008, Harvest had $1,226.2 million drawn of the $1.6 billion available under the Credit Facility ($1,279.5 million drawn at December 31, 2007).

The Credit Facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. The most restrictive covenants of Harvest's credit facility include an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge, a limitation to carrying on business in countries that are not members of the

Organization of Economic Co-operation and Development and a limitation on the payment of distributions to Unitholders in certain circumstances such as an event of default. The Credit Facility requires standby fees on undrawn amounts and interest on amounts borrowed at varying rates depending on Harvest's ratio of secured debt (excluding the 7⅞% Senior Notes and Convertible Debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). In addition to the availability under this facility being limited by the Borrowing Base Covenant of the 7⅞% Senior Notes described (as described in Note 11), availability is subject to the following quarterly financial covenants:

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

For the year ended December 31, 2008, Harvest's average interest rate on advances under the Credit Facility was 4.12% (2007 – 5.28%) and nil (2007 – 6.08%) for Canadian and U.S advances, respectively.

11. 7⅞% Senior Notes

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of 7⅞% Senior Notes for cash proceeds of $311,951,000. The 7⅞% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year, mature on October 15, 2011 and are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries. Prior to maturity, redemptions are permitted as follows:

- After October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

The 7⅞% Senior Notes contains a change of control covenant that requires Harvest Operations Corp. to commence an offer to re-purchase the 7⅞% Senior Notes at a price of 101% of the principal amount plus accrued interest within 30 days of a change of control event, as defined in the indenture. There are also covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1. Notwithstanding the interest coverage ratio limitation, the incurrence of additional indebtedness under the Credit Facilities may be limited by the Borrowing Base Covenant (as described below) and certain other specific circumstances.

The covenants of the 7⅞% Senior Notes also restrict Harvest's incurrence of secured indebtedness to an amount less than 65% of the present value of the future net revenues from its proven petroleum and natural gas reserves discounted at an annual rate of 10% (the "Borrowing Base Covenant"). At December 31, 2008, the Borrowing Base Covenant restricts secured indebtedness to Cdn$1.91 billion (at December 31, 2007 - Cdn$1.86 billion).

In addition, the covenants of the 7⅞% Senior Notes restrict Harvest's ability to pay distributions to Unitholders (net of distributions settled with the delivery of Trust Units) during a quarter to 80% of the prior quarter's cash flow from operating activities before settlement of asset retirement obligations and changes in non-cash working capital if Harvest's interest coverage ratio as described in the agreement is greater than 2.5 to 1.0 and its consolidated leverage ratio is lower than 3.0 to 1.0. Notwithstanding, distributions are permitted provided that from the date of issuance of the 7⅞% Senior Notes, the aggregate distributions do not exceed an amount equal to $40 million plus 100% of the net cash proceeds from the sale of Trust Units plus 80% of the cumulative cash flow from operating activities less distributions paid which as at December 31, 2008, amounted to a carry-forward of approximately Cdn$1.5 billion (Cdn$1.5 billion as at December 31, 2007).

The fair value of the 7⅞% Senior Notes at December 31, 2008 was US$231.4 million (2007 - $232.6 million).

12. Convertible Debentures

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

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective redemption dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time.

Harvest may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The covenants of the Convertible Debentures restrict Harvest's issuance of additional convertible debentures if the principal amount of all of its issued and outstanding convertible debentures immediately after the issuance of such additional convertible debentures exceeds 25% of the Total Market Capitalization, as defined. Total Market Capitalization is defined as the total principal amount of all issued and outstanding convertible debentures plus the amount obtained by multiplying the number of issued and outstanding Trust Units by the current value of the Trust Units. As at December 31, 2008, Harvest's Total Market Capitalization was approximately Cdn$2.6 billion (Cdn$3.8 billion as at December 31, 2007).

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

Series	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
9% Debentures Due 2009	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debentures Due 2009	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debentures Due 2010	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
6.40% Debentures Due 2012(1)	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debentures Due 2013(1)	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debentures Due 2014(1)	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12
7.5% Debentures Due 2015(1)	$ 27.40	May 31, 2015	Jun. 1/11-May 31/12	Jun. 1/12-May 31/13

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

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

	December 31, 2008			December 31, 2007		
	Face Value	**Carrying Amount(1)**	**Fair Value**	Face Value	Carrying Amount(1)	Fair Value
9% Debentures Due 2009	**$ 944**	**$ 940**	**$ 984**	$ 976	$ 962	$ 1,806
8% Debentures Due 2009	**1,588**	**1,573**	**1,540**	1,728	1,692	2,022
6.5% Debentures Due 2010	**37,062**	**35,387**	**29,650**	37,062	34,653	35,950
10.5% Debentures Due 2008	**-**	**-**	**-**	24,258	24,273	24,258
6.40% Debentures Due 2012	**174,626**	**169,455**	**75,089**	174,626	168,325	148,432
7.25% Debentures Due 2013	**379,256**	**358,533**	**166,835**	379,256	355,145	344,895
7.25% Debentures Due 2014	**73,222**	**67,549**	**36,611**	73,222	66,718	65,892
7.5% Debentures Due 2015	**250,000**	**194,322**	**107,500**	-	-	-
	$ 916,698	**$ 827,759**	**$ 418,209**	$ 691,128	$ 651,768	$ 623,255

(1) Excluding the equity component.

On January 31, 2008, the 10.5% Debenture matured and Harvest elected to settle its obligation by issuing 1,166,593 Trust Units rather than settling in cash.

On April 25, 2008, Harvest issued $250 million principal amount of 7.5% Convertible Debentures for total net proceeds from the issue of $239.5 million. These debentures mature on May 31, 2015 and have a conversion price of $27.40.

13. Normal Course Issuer Bid

On October 20, 2008, the Toronto Stock Exchange approved our Normal Course Issuer Bid to purchase for cancellation, subject to daily limits, up to 10% of the outstanding Trust Units and Convertible Debentures not held by insiders on the open market at the prevailing market prices at the time of such purchase. To date, there have been no such purchases.

14. Unitholders' Capital

(a) Authorized

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

(b) Number of Units Issued

	Year ended December 31	
	2008	2007
Outstanding, beginning of year	**148,291,170**	122,096,172
Issued for cash		
February 1, 2007	**-**	6,146,750
June 1, 2007	**-**	7,302,500
Convertible debenture conversions		
9% Debentures Due 2009	**2,310**	18,047
8% Debentures Due 2009	**8,710**	31,790
6.5% Debentures Due 2010	**-**	27,967
10.5% Debentures Due 2008	**344**	81,478
6.40% Debentures Due 2012	**-**	2,542
7.25% Debentures Due 2013	**-**	7,574
7.25% Debentures Due 2014	**-**	5,753,310
Redemption of convertible debentures		
10.5% Debentures Due 2008	**1,166,593**	-
Distribution reinvestment plan issuance	**7,655,414**	6,809,987
Exercise of unit appreciation rights and other	**76,160**	13,053
Outstanding, end of year	**157,200,701**	148,291,170

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

(c) Per Trust Unit Information

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

Net income adjustments	**December 31, 2008**	December 31, 2007
Net (loss) income, basic	**$ 212,019**	$ (25,676)
Interest on Convertible Debentures	**95**	-
Net income, diluted(1)	**$ 212,114**	$ (25,676)

Weighted average Trust Units adjustments	**December 31, 2008**	December 31, 2007
Number of Units		
Weighted average Trust Units outstanding, basic	**152,836,717**	138,440,869
Effect of Convertible Debentures	**69,155**	-
Effect of Employee Unit Incentive Plans	**200,789**	-
Weighted average Trust Units outstanding, diluted(2)	**153,106,661**	138,440,869

(1) Net income, diluted excludes the impact of the conversions of certain of the Convertible Debentures of $69.4 million for the year ended December 31, 2008 (2007 - $59.2 million), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the year ended December 31, 2008 does not include the unit impact of 25,915,000 for certain of the Convertible Debentures (2007 – 23,636,000) and nil (2007 – 682,000) for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

15. Contributed Surplus

Contributed surplus of $6.4 million has been recorded during the year ended December 31, 2008 due to the maturity of the 10.5% Debentures and the resulting expiration of the conversion option which was previously recorded in equity component of convertible debentures.

16. Capital Structure

Harvest's primary objective in its management of capital resources is to ensure sufficient financial flexibility to access capital to fund its financial obligations as well as future growth. Harvest considers its capital structure to comprise its credit facilities, 7⅞% Senior Notes, Convertible Debentures and unitholders' equity.

Harvest monitors its capital structure using the following non-GAAP financial ratios: bank debt to Twelve Month Trailing Earnings Before Interest, Taxes, Depreciation and Amortization and non-cash amounts ("EBITDA"), secured debt to net present value of our proved petroleum and natural gas reverses discounted at 10% and total debt to total debt plus unitholders' equity. Total debt includes borrowings under credit facilities plus our 7⅞% Senior Notes and principal amount of Convertible Debentures and unitholders' equity is adjusted to remove the equity component of convertible debentures.

Harvest's capital management strategy with regards to our bank debt is to maintain a bank debt to EBITDA ratio between 1.0 and 2.5 times. This ratio is calculated as follows:

		December 31, 2008		December 31, 2007
Cash provided by operating activities	$	655,887	$	641,313
Settlement of asset retirement obligations		11,418		13,090
Change in non-cash working capital		9,897		17,384
Interest paid		132,473		145,742
Large Corporations Tax and other taxes paid		(81)		(974)
Total EBITDA	$	809,594	$	816,555
Bank debt	$	1,226,228	$	1,279,501
Bank debt to EBITDA		1.51		1.57

With respect to its secured debt, Harvest's strategy is to target its secured debt to less than 65% of the net present value of its proved petroleum and natural gas reserves discounted at 10% (as determined on an annual basis) by at least $200 million.

		December 31, 2008		December 31, 2007
Proved petroleum and natural gas reserves (Net Present Value discounted at 10%)	$	2,941,452	$	2,865,200
65% of Proved petroleum and natural gas reserves	$	1,911,944	$	1,862,380
Secured debt (borrowings under Credit Facilities)	$	1,226,228	$	1,279,501

Harvest targets its total debt to total debt plus unitholders' equity to be a ratio between 0.25 and 0.55 times calculated as follows:

		December 31, 2008		December 31, 2007
Bank debt	$	1,226,228	$	1,279,501
7⅞% Senior Notes (1)		304,500		247,825
Principal amount of convertible debentures		916,698		691,128
Total Debt		2,447,426		2,218,454
Unitholders' equity (less equity component of convertible debentures)		2,559,229		2,445,837
Total debt plus unitholders' equity	$	5,006,655	$	4,664,291
Total debt to total debt plus unitholders' equity		0.49		0.48

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

Harvest's capital structure is limited by a covenant in its Convertible Debenture Indenture which currently restricts the issuance of additional convertible debentures. In addition, although Harvest's Trust Unit Indenture provides for the issuance of an unlimited number of Trust Units, the "normal growth guidelines" contained in Bill C-52 issued by the Government of Canada limits the future issuance of Convertible Debentures and Trust Units at December 31, 2008 to approximately $2.4 billion (2007 - $2.8 billion) with any unused normal growth available for use prior to 2011. Included in this amount is approximately $590 million (2007 - $590 million) that the Trust may issue to replace debt held on October 31, 2006.

At December 31, 2008, all covenants related to the bank loan (Note 10), Senior Notes (Note 11) and Convertible Debentures (Note 12) were met.

Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting its objectives as outlined above. Accordingly, Harvest may adjust its capital spending programs, adjust the amount of distributions paid to Unitholders, issue new Trust Units, Convertible Debentures or Senior Notes or repay existing debt. Harvest's capital management targets have remained unchanged during the year ended December 31, 2008.

17. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

Harvest is authorized to grant non-transferable unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding Trust Units and the number of Trust Units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the Trust Units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the Trust Units subsequent to the date of grant of the respective right, provided that Harvest's net operating cash flow (on an annualized basis) exceeds 10% of Harvest's recorded cost of property, plant and equipment 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 property, plant and equipment. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in a lump sum cash payment after the rights have been exercised.

Upon the exercise of unit appreciation rights the holder has the sole discretion to elect to receive cash or units. As a result, Harvest recognizes a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represents the difference between the market value of the Trust Units and the exercise price of the vested unit rights outstanding under the plan. As such, an obligation of $0.3 million (2007 - $1.4 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 8,037,446 (2007 – 3,823,683) Trust Unit Rights outstanding under the plan at December 31, 2008. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

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

	Year ended December 31, 2008		Year ended December 31, 2007	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of year	**3,823,683**	**$ 30.74**	3,788,125	$ 30.81
Granted	**5,244,102**	**15.68**	576,383	29.03
Exercised	**(68,675)**	**25.67**	(92,775)	21.88
Forfeited	**(961,644)**	**28.80**	(448,050)	31.10
Outstanding before exercise price reductions	**8,037,466**	**21.19**	3,823,683	30.74
Exercise price reductions	**-**	**(4.45)**	-	(6.11)
Outstanding, end of year	**8,037,466**	**16.74**	3,823,683	$ 24.63
Exercisable before exercise price reductions	**85,200**	**$ 22.60**	145,950	$ 23.08
Exercise price reductions	**-**	**(15.49)**	-	(12.17)
Exercisable, end of year	**85,200**	**$ 7.11**	145,950	$ 10.91

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2008.

		Outstanding			**Exercisable**	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At December 31, 2008**	**Weighted Average Exercise Price net of price reductions**(1)	**Remaining Contractual Life** (1)	**At December 31, 2008**	**Weighted Average Exercise Price net of price reductions**(1)
$ 10.39-$12.51	$ 9.49-$12.21	3,185,230	$ 10.38	5.0	-	$ -
$ 14.99-$18.90	$ 0.01-$17.73	50,600	10.93	3.2	18,750	0.29
$ 19.29-$25.37	$ 4.87-$23.48	1,894,053	19.96	4.1	66,450	9.03
$ 26.09-$31.96	$ 15.23-$25.55	1,527,033	18.73	3.0	-	-
$ 32.01-$37.56	$ 19.13-$28.79	1,380,550	24.99	2.3	-	-
$ 10.39-$37.56	$ 0.01-$28.79	8,037,466	$ 16.74	3.9	85,200	$ 7.11

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

Unit Award Incentive Plan ("Unit Award Plan")

The Unit Award Plan authorizes Harvest to grant awards of Trust Units to directors, officers, employees and consultants of Harvest and its affiliates to an aggregate of a rolling maximum of 0.5% of the outstanding Trust Units and the number of Trust Units issuable upon the exercise of any outstanding exchangeable shares. Subject to the Board of Directors' discretion, awards vest annually over a two to four year period and, upon vesting, entitle the holder to elect 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. Harvest recognizes a liability on its consolidated balance sheet associated with the awards granted under the plan. This obligation represents the fair value of the vested Trust Units granted under the Unit Award Plan. As such, an obligation of $3.6 million (2007 - $5.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 659,137 (2007 – 348,248) Unit Awards outstanding under the plan at December 31, 2008. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date.

Number	December 31, 2008	December 31, 2007
Outstanding, beginning of year	**348,248**	306,699
Granted	**390,274**	56,132
Adjusted for distributions	**75,310**	48,280
Exercised	**(121,776)**	(37,072)
Forfeitures	**(32,919)**	(25,791)
Outstanding, end of year	**659,137**	348,248
Exercisable, end of year	**238,817**	168,401

Harvest has recognized a compensation recovery of $0.7 million (2007 – $2.7 million expense), including a non cash compensation recovery of $1.7 million (2007 – $0.6 million expense), for the year ended December 31, 2008, related to the Trust Unit Rights Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

18. Income Taxes

The future income tax provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the Trust and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in future income tax expense.

In the Second Quarter of 2007, the Canadian government enacted legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. In the Fourth Quarter of 2007, the tax rate for trust distributions was reduced to 29.5% for 2011 and to 28% for 2012 and subsequent years. The new tax is not expected to apply to Harvest until 2011, as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. This portion of the Trust's future income tax liability represents its tax-effected portion of December 31, 2008 temporary differences that it estimates will exist on January 1, 2011, pursuant to the current legislation and Harvest's current structure.

Concurrent with the tax rate reductions referred to above, further reductions in Federal corporate income tax rates were enacted. Under the legislation, Federal corporate rates will decline until 2012, resulting in an effective tax rate for the Trust's corporate entities of approximately 25%, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

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

	Year ended December 31			
		2008		2007
Income before taxes	**$**	**320,498**	$	39,152
Combined Canadian Federal and Provincial statutory income tax rate		**29.85%**		32.70%
Computed income tax expense at statutory rates		**95,669**		12,803
Income earned by flow through entities		**(109,335)**		(179,750)
Expected tax expense (recovery) in corporate entities		**(13,666)**		(166,947)
Increased expense (recovery) resulting from the following:				
Temporary differences acquired in excess of fair value limitation		**944**		-
Initial recognition of trust temporary differences		**-**		271,705
Benefit of future tax deductions previously unrecognized		**-**		(72,073)
Difference between current and expected tax rates		**113,655**		44,547
Non-taxable portion of capital (gain) loss		**8,216**		(20,515)
Change in estimates of future temporary differences		**(1,231)**		8,860
Non-deductible expenses		**642**		225
Future income tax expense		**108,560**		65,802

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

	Year ended December 31			
		2008		2007
Net book value of petroleum and natural gas assets in excess of tax pools	**$**	**498,725**	$	333,466
Net book value of intangible assets in excess of tax pools		**16,640**		13,998
Asset retirement obligation		**(73,899)**		(56,066)
Net unrealized losses related to risk management contracts and currency exchange positions – current		**7,124**		(38,642)
Net unrealized losses related to risk management contracts and currency exchange positions – long-term		**1,177**		304
Non-capital loss carry forwards for tax purposes		**(241,660)**		(161,706)
Deferral of taxable income in partnership		**554**		1,492
Future employee retirement costs		**(3,135)**		(3,607)
Working capital and other items		**(1,528)**		(2,599)
Future income tax liability (asset), net	**$**	**203,998**	$	86,640

The expiry dates on the consolidated non-capital losses are as follows:

Year of Expiry		
2009	**$**	**12,667**
2013		**9,768**
2014		**40,110**
2025		**97,300**
2026		**40,958**
2027		**455,729**
2028		**342,423**
Consolidated non-capital losses	**$**	**998,955**

See Commitments, Contingencies and Guarantees [Note 22(f)].

19. Employee Future Benefit Plans

Defined Benefit Plans

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

	December 31, 2008		December 31, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Discount rate	**7.25%**	**7.25 %**	5.0%	5.0 %
Expected long-term rate of return on plan assets	**7.0%**	**-**	7.0%	-
Rate of compensation increase	**3.5%**	**-**	3.5%	-
Employee contribution of pensionable income	**6.0%**	**-**	6.0%	-
Annual rate of increase in covered health care benefits	**-**	**10%**	-	11%
Expected average remaining service lifetime (years)	**11.7**	**10.7**	11.7	10.8

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

	December 31, 2008	December 31, 2007
Bonds/fixed income securities	**36%**	32%
Equity securities	**64%**	68%

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

The defined benefit pension plans were subject to an actuarial valuation on December 31, 2008 and the next valuation report is due no later than December 31, 2011. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2008.

	December 31, 2008		December 31, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of year	**$ 49,082**	**$ 6,653**	$ 43,101	$ 6,027
Current service costs	**3,355**	**370**	3,043	369
Interest	**2,673**	**346**	2,357	316
Actuarial losses (gains)	**(13,086)**	**(1,795)**	1,409	162
Benefits paid	**(1,372)**	**(276)**	(828)	(221)
Employee benefit obligation, end of year	**40,652**	**5,298**	49,082	6,653
Fair value of plan assets, beginning of year	**38,903**	**-**	36,576	-
Actual return on plan assets	**(7,587)**	**-**	(1,682)	-
Employer contributions	**3,485**	**199**	3,428	221
Employee contributions	**1,703**	**77**	1,409	-
Benefits paid	**(1,372)**	**(276)**	(828)	(221)
Fair value of plan assets, end of year	**35,132**	**-**	38,903	-
Funded status	**(5,520)**	**(5,298)**	(10,179)	(6,653)
Unamortized balances:				
Net actuarial losses	**267**	**-**	4,664	-
Carrying amount	**$ (5,253)**	**$ (5,298)**	$ (5,515)	$ (6,653)

	December, 31, 2008		December 31, 2007	
Summary:				
Pension plans	**$**	**5,253**	$	5,515
Other benefit plans		**5,298**		6,653
Carrying amount	**$**	**10,551**	$	12,168

Estimated pension and other benefit payments to plan participants which reflect expected future service, expected to be paid from 2009 to 2018, are as follows:

	Pension Plans		Other Benefit Plans	
2009	$	1,394	$	333
2010		1,640		468
2011		1,875		561
2012		2,143		686
2013		2,457		828
2014 to 2018		19,547		6,790
Total	$	29,056	$	9,666

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

	Year ended December 31, 2008				Year ended December 31, 2007			
	Pension Plans		**Other Benefit Plans**		Pension Plans		Other Benefit Plans	
Current service cost	**$**	**3,355**	**$**	**370**	$	3,043	$	369
Interest costs		**2,673**		**346**		2,357		316
Expected return on assets		**(2,806)**		**-**		(2,657)		-
Amortization of net actuarial losses		**-**		**(1,872)**		-		101
Net benefit plan expense	**$**	**3,222**	**$**	**(1,156)**	$	2,743	$	786

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2008:

	1% Increase		1% Decrease	
Impact on post-retirement benefit expense	$	1	$	(1)
Impact on projected benefit obligation		13		(20)

20. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, Convertible Debentures and the 7⅞% Senior Notes. The carrying value and fair value of these financial instruments at December 31, 2008 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the year ended December 31, 2008:

	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	$ 173,341	$ 173,341	$ -	$ 329[(2)]	$ -
Assets Held for Trading					
Net fair value of risk management contracts	35,852	35,852	(14,861)[(3)]	-	-
Other Liabilities					
Accounts payable	210,097	210,097	-	-	-
Cash distribution payable	47,160	47,160	-	-	-
Bank loan	1,226,228	1,226,228	-	(51,855)[(4)]	(2,699)[(4)]
7⅞% Senior Notes	298,210[(1)]	231,420	-	(22,662)[(5)]	-
Convertible Debentures	$ 827,759	$ 418,209	$ -	$ (69,454)[(5)]	$ -

(1) The face value of the 7⅞% Senior Notes at December 31, 2008 is $304.5 million (U.S. $250 million).

(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.

(3) Included in risk management contracts - realized and unrealized gains (losses) in the statement of income and comprehensive income.

(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in amortization of deferred finance charges in the statement of cash flows.

(5) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.

The fair values of the Convertible Debentures and the 7⅞% Senior Notes are based on quoted market prices as at December 31, 2008. The risk management contracts are recorded on the balance sheet at their fair value; accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but as there are no transaction costs associated with our bank debt and the financing costs are included in intangible assets, there is no difference between the carrying value and the fair value. Due to the short term nature of accounts receivable, accounts payable, cash distribution payable and the bank loan, their carrying values approximate their fair values.

(a) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk relating to our debt.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in our upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, Harvest requests a guarantee from the parent company that does have a credit rating. If this is not possible, Harvest performs an internal credit review based on the purchaser's past financial performance. The credit risk associated with joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash prior to incurring significant capital costs on their behalf. Additionally, most agreements have a provision enabling Harvest to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to offset amounts owing from the partner that is in default. Generally, the only instances of impairment are when a purchaser or partner is facing bankruptcy or extreme financial distress.

Risk Management Contract Counterparties

Harvest is also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and limiting those counterparties to lenders in our syndicated credit facilities; we have no history of impairment with these counterparties.

Downstream Accounts Receivable

The Supply and Offtake Agreement entered into in conjunction with the purchase of the downstream operations exposed Harvest to the credit risk of Vitol Refining S.A. ("Vitol") as all feedstock purchases and the majority of product sales are made with Vitol under this agreement. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poor's Rating Services. If the credit rating falls below this line, additional security is required to be supplied to Harvest. This credit risk is also mitigated by the amounts owing to Vitol for feedstock purchases that are offset against amounts receivable from Vitol for product sales with the balance being net settled. Harvest is in a net payable position with Vitol at December 31, 2008 and accordingly the outstanding balance is included in current trade accounts payable in the liability liquidity table below.

Harvest's policy is to manage its credit risk by dealing with only financially sound customers, based on an evaluation of the customer's financial condition. At December 31, 2008, Harvest had an accounts receivable balance with one customer of $5.1 million resulting from the sale of refined product, representing approximately 8% of total downstream accounts receivable. This customer is an integrated multinational energy company with an AA public credit rating.

Our maximum exposure to credit risk relating to the above classes of financial assets at December 31, 2008 is the carrying value of accounts receivable. The table below provides an analysis of our current financial assets and the age of our past due but not impaired financial assets by type of credit risk.

	Current AR	Overdue AR			
		< 30 days	> 30 days, < 60 days	> 60 days, < 90 days	> 90 days
Upstream Accounts Receivable	$ 79,112	$ 1,260	$ 2,498	$ 1,256	$ 20,908
Risk Management Contract Counterparties	825	-	-	-	-
Downstream Accounts Receivable	59,982	3,094	800	510	3,096
Total	**$ 139,919**	**$ 4,354**	**$ 3,298**	**$ 1,766**	**$ 24,004**

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to our borrowings under our credit facilities and 7⅞% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations, complying with covenants and managing our cash flow by entering into price risk management contracts. Additionally, when we enter into price risk management contracts we select counterparties that are also lenders in our syndicated credit facility thereby using the security provided in our credit agreement eliminating the requirement for margin calls and the pledging of collateral.

The following table provides an analysis of our financial liability maturities based on the remaining terms of our liabilities as at December 31, 2008 and includes the related interest charges:

	<1 year	>1 year <3 years	>4 years <5 years	>5 years	Total
Trade accounts payable and accrued liabilities	$ 188,941	$ -	$ -	$ -	$ 188,941
Distributions payable	47,160	-	-	-	47,160
Bank loan and interest	28,632	1,235,563	-	-	1,264,195
Convertible debentures interest(1)	65,269	127,864	105,386	27,300	325,819
7⅞% Senior Notes and interest	23,979	347,334	-	-	371,313
Pension contributions	6,900	14,217	14,791	7,618	43,526
Asset retirement obligations	14,214	30,790	26,958	1,131,823	1,203,785
Total	**$ 375,095**	**$1,755,768**	**$ 147,135**	**$1,166,741**	**$3,444,739**

(1) Convertible Debentures are typically converted into Trust Units prior to maturity or are redeemed for Trust Units at maturity by Harvest; therefore, only the interest portion is represented in the table above. At the Trust's option, the interest on Convertible Debentures may also be settled in Trust Units.

(iii.) Market Risks and Sensitivity Analysis

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

We have performed sensitivity analysis on the three types of market risks identified, assuming that the volatility of the risks over the next quarter will be similar to that experienced in the past year. Harvest has determined that a reasonably possible price or rate variance over the next reporting period for a given risk variable can be estimated by calculating two standard deviations for each three month period in the last year for the relevant daily price/rate settings and using an average of the standard deviation as a reasonable estimate of the expected variance. This variance is then applied to the relevant period end rate or price to determine a reasonable percentage increase and decrease in the risk variable which can then be applied to the outstanding risk exposure at period end. Using 12 months of data, we factor in the seasonality of our business and the price volatility therein.

Interest rate risk

Harvest is exposed to interest rate risk on its bank borrowings as interest rates are determined in relation to floating market rates plus an incremental charge based on our secured debt to EBITDA. Harvest's Convertible Debentures and 7⅞% Senior Notes have fixed interest rates and therefore do not have any additional interest rate risk. Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

For the year ended December 31, 2008, interest charges on bank loans aggregated to $49.6 million (2007 - $43.8 million), reflecting an effective interest rate of 4.12% (2007 – 5.28%).

At December 31, 2008, if interest rates had decreased by 70% with all other variables held constant, after-tax net income for the year would have been $12.8 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 70%, with all other variables held constant, the after-tax net income would have been $12.8 million lower.

Currency exchange rate risk

Harvest is exposed to the risk of changes in the U.S. dollar exchange rate on its U.S. dollar denominated revenues as well as Canadian dollar revenues that are based on a U.S. dollar commodity price. In addition, Harvest's 7⅞% Senior Notes are denominated in U.S. dollars (U.S.$250 million) and interest on these notes is payable semi-annually in U.S. dollars and accordingly the principal and any interest payable at the balance sheet date are also subject to currency exchange rate risk. Harvest is also exposed to currency exchange rate risk on its net investment in our downstream operations which is a self sustaining subsidiary that uses a U.S. dollar functional currency. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales receipts.

At December 31, 2008, if the U.S. dollar strengthened or weakened by 8% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

	Impact on Net Income	
U.S. Dollar Exchange Rate - 8% increase	$	(24,249)
U.S. Dollar Exchange Rate - 8% decrease	$	24,249

As mentioned above, Harvest's downstream operations operates with a U.S. dollar functional currency which gives rise to currency exchange rate risk on North Atlantic Refining LP's Canadian dollar denominated monetary assets and liabilities, such as Canadian dollar bank accounts and accounts receivable and payable, as follows:

	Impact on Net Income	
Canadian Dollar Exchange Rate - 8% increase	$	(20,503)
Canadian Dollar Exchange Rate - 8% decrease	$	20,503

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its crude oil, natural gas and refined product sales price exposure and power costs. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value reported in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as changes will result in a gain or loss that we will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at December 31, 2008, net income would be impacted as follows:

		Impact on NI	
Contract	**% Change**	**Due to % increase**	**Due to % decrease**
Heating Oil NYMEX	**65%**	**$ (50,678)**	**$ -**
#6 (1%) HFO Platts	**75%**	**(13,457)**	**-**
Total		**$ (64,135)**	**$ -**

(b) Fair Values

At December 31, 2008, the net fair value reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $35.9 million (2007 - $149.7 million deficiency), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $36.1 million, fair value deficiency of risk management contracts (current liabilities) $0.2 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2008:

Quantity	Type of Contract	Term	Average Price	Fair value
Refined Product Price Risk Management				
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)[a] [c]	$ 26,808
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)[b]	9,279
				$ 36,087
Natural Gas Price Risk Management				
251 GJ/d	Fixed price – natural gas contract	Jan. 09 – Dec. 09	Cdn$3.48[d]	$ (235)
Total net fair value of risk management contracts				**$ 35,852**

(a) If the market price is below the floor price of $72.59, price received is market price plus $13.93; if the market price is between the floor price of $72.59 and $86.52, the price received is $86.52; if the market price is between $86.52 and the ceiling of $98.73, the price received is market price; if the market price is over the ceiling of $98.73, price received is $98.73.

(b) If the market price is below the floor of $49.75, price received is market price plus $7.63; if the market price is between the floor price of $49.75 and $57.38, the price received is $57.38; if the market price is between $57.38 and the ceiling of $65.89, the price received is market price; if the market price is over the ceiling of $65.89, price received is $65.89.

(c) Heating oil contracts are contracted in U.S. dollars per U.S. gallon and are presented in this table in U.S. dollars per barrel for comparative purposes (1 barrel equals 42 U.S. gallons).

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

For the year ended December 31, 2008, the total unrealized gain recognized in the consolidated statement of income and comprehensive income was $185.9 million (2007 - a loss of $147.8 million), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

21. Segment Information

Harvest operates in Canada and has two reportable operating segments, Upstream and Downstream. Harvest's upstream operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids, while its downstream operations include the purchase of crude oil, the refining of crude oil, the sale of the refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

Results of Continuing Operations	Downstream[1]		Upstream[1]		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenue[2]	**$ 4,194,595**	$ 3,098,556	**$ 1,543,214**	$ 1,184,457	**$ 5,737,809**	$ 4,283,013
Royalties	**-**	-	**(248,445)**	(213,413)	**(248,445)**	(213,413)
Less:						
Purchased products for resale and processing	**3,850,507**	2,667,714	**-**	-	**3,850,507**	2,667,714
Operating[3]	**236,259**	229,290	**300,890**	300,918	**537,149**	530,208
Transportation and marketing	**20,753**	34,970	**13,490**	11,946	**34,243**	46,916
General and administrative	**1,875**	1,713	**32,868**	34,615	**34,743**	36,328
Depletion, depreciation, amortization and accretion	**71,076**	72,599	**448,735**	454,142	**519,811**	526,741
	$ 14,125	$ 92,270	**$ 498,786**	$ 169,423	**512,911**	261,693
Realized net losses on risk management contracts					**(200,782)**	(26,291)
Unrealized net gains (losses) on risk management contracts					**185,921**	(147,781)
Interest and other financing charges on short term debt					**(295)**	(5,584)
Interest and other financing charges on long term debt					**(146,375)**	(152,201)
Currency exchange gain (loss)					**(30,882)**	109,316
Large corporations tax recovery and other tax					**81**	974
Future income tax					**(108,560)**	(65,802)
Net (loss) income					**$ 212,019**	$ (25,676)
Total Assets[4]	**$ 1,775,688**	$ 1,482,904	**$ 3,933,632**	$ 3,952,337	**$ 5,745,407**	$ 5,451,683
Capital Expenditures						
Development and other activity	**$ 56,162**	$ 44,111	**$ 271,312**	$ 300,674	**$ 327,474**	$ 344,785
Business acquisitions	**-**	-	**36,756**	170,782	**36,756**	170,782
Property acquisitions	**-**	-	**138,493**	27,943	**138,493**	27,943
Property dispositions	**-**	-	**(46,476)**	(60,569)	**(46,476)**	(60,569)
Total expenditures	**$ 56,162**	$ 44,111	**$ 400,085**	$ 438,830	**$ 456,247**	$ 482,941
Property, plant and equipment						
Cost	**$ 1,493,039**	$ 1,164,310	**$ 4,710,725**	$ 4,247,819	**$ 6,203,764**	$ 5,412,129
Less: Accumulated depletion, depreciation, amortization and accretion	**(162,810)**	(72,277)	**(1,572,449)**	(1,142,345)	**(1,735,259)**	(1,214,622)
Net book value	**$ 1,330,229**	$ 1,092,033	**$ 3,138,276**	$ 3,105,474	**$ 4,468,505**	$ 4,197,507
Goodwill						
Beginning of year	**$ 175,984**	$ 209,930	**$ 676,794**	$ 656,248	**$ 852,778**	$ 866,178
Addition (reduction) to goodwill	**40,246**	(33,946)	**817**	20,546	**41,063**	(13,400)
End of year	**$ 216,230**	$ 175,984	**$ 677,611**	$ 676,794	**$ 893,841**	$ 852,778

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies.

(2) Of the total downstream revenue for the year ended December 31, 2008, two customers represent sales of $2,818.1 million and $592.0 million respectively (2007 - $2,651.5 million and nil). No other single customer within either division represents greater than 10% of Harvest's total revenue.

(3) Downstream operating expenses for the period ended December 31, 2008 include $5.6 million of turnaround and catalyst costs (2007 - $34.5 million).

(4) Total Assets on a consolidated basis includes $36.1 million (2007 - $16.4 million) relating to the fair value of risk management contracts.

(5) There is no intersegment activity.

22. Commitments, Contingencies and Guarantees

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

The following are the significant commitments and contingencies at December 31, 2008:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement, which continues on a monthly basis with a mutual six months termination notice period, provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, at December 31, 2008, North Atlantic had commitments totaling approximately $319.7 million (2007 - $843.6 million) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) North Atlantic has an agreement with Newsul Enterprises Inc. ("Newsul") whereby North Atlantic committed to provide Newsul with its inventory and production of sulphur to February 12, 2018.

Newsul has named North Atlantic in a claim in the amount of US$2.7 million and has requested the services of an arbitration board to make a determination on the claim. The claim is for additional costs and lost revenues related to alleged contaminated sulphur delivered by North Atlantic. An accrual of $0.5 million has been established based on North Atlantic's estimate of their liability, but since the eventual outcome of the arbitration hearing is undeterminable, there exists an exposure to loss in excess of the amount accrued.

(c) North Atlantic has an environmental agreement with the Province of Newfoundland and Labrador, Canada, committing to programs that reduce the environmental impact of the refinery over time. Initiatives include a schedule of activities to be undertaken with regard to improvements in areas such as emissions, waste water treatment, terrestrial effects, and other matters. In accordance with the agreement, certain projects have been completed and others have been scheduled. Costs relating to certain activities scheduled to be undertaken over the next two years are estimated to be approximately $3.3 million and are included in the table below; costs can not yet be estimated for the remaining projects.

(d) North Atlantic has been named a defendant in The State of New Hampshire versus Amerada Hess Corp. et al, one of more than 100 methyl tertiary butyl ether ("MTBE") U.S. product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated lawsuits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the consolidated financial statements in respect of this matter. Harvest is indemnified by Vitol Group B.V. in respect of this contingent liability.

(e) Petro-Canada, a former owner of the North Atlantic refinery, holds certain contractual rights in relation to production at the refinery, namely:

i. a right to share, subject to a maximum limit, in the profits of the sale of any refined product, refined at the refinery, sold in Canada, exclusive of the province of Newfoundland and Labrador;

ii. a right of first refusal to any refinery and/or terminaling capacity in excess of North Atlantic's requirements;

iii. a right to participate in any venture to produce petrochemicals at the refinery; and

iv. the rights in paragraphs (i) and (ii) above continue for a period of 25 years from December 1, 1986, while the rights in paragraph (iii) continue until amended by the parties.

(f) *Canada Revenue Agency Assessment*

In January 2009, Canada Revenue Agency issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted Harvest Energy Trust's taxable income to include their net profits interest royalty income on an accrual basis whereas the tax returns had reported this revenue on a cash basis. A Notice of Objection has been filed with CRA requesting the adjustments to an accrual basis be reversed. The Harvest Energy Trust 2005 tax return has also been prepared on a cash basis for royalty income with no taxes payable and, if reassessed by CRA on a similar basis, there would have been approximately $40 million of taxes owing. The Harvest Energy Trust 2006 tax return has been prepared on an accrual basis including incremental payments required to align the prior year's cash basis of reporting with no taxes payable. Management along with our legal advisors believe the CRA has not properly applied the provisions of the Income Tax Act (Canada) that entitle income from a royalty to be included in taxable income on a cash basis and that the dispute will be resolved with no taxes payable by Harvest Energy Trust.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2008:

Payments Due by Period	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Debt repayments(1)	-	1,226,228	304,500	-	-	-	**1,530,728**
Debt interest payments(2)	117,881	98,447	81,586	60,838	44,549	27,299	**430,600**
Capital commitments(3)	36,537	-	-	-	-	-	**36,537**
Operating leases(4)	7,868	7,005	6,069	2,274	566	566	**24,348**
Pension contributions(5)	6,900	7,038	7,179	7,322	7,469	7,618	**43,526**
Transportation agreements(6)	2,744	2,266	936	544	189	-	**6,679**
Feedstock commitments(7)	319,746	-	-	-	-	-	**319,746**
Contractual obligations	**491,676**	**1,340,984**	**400,270**	**70,978**	**52,773**	**35,483**	**2,392,164**

(1) Assumes that the outstanding Convertible Debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.

(2) Interest determined on bank loan balance and rate effective at year end and by using the year end U.S. dollar exchange rate for the Senior Notes. At the Trust's option the interest on Convertible Debentures can be settled in Trust Units.

(3) Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.

(4) Relating to building and automobile leases.

(5) Relating to expected contributions for employee benefit plans [see Note 19].

(6) Relating to oil and natural gas pipeline transportation agreements.

(7) Relating to crude oil feedstock purchases and related transportation costs [see Note 22(a) above].

23. Reconciliation of the Consolidated Financial Statements to United States Generally Accepted Accounting Principles

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

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

	Year Ended December 31	
	2008	2007
Net income (loss) under Canadian GAAP	**$ 212,019**	$ (25,676)
Adjustments		
Write-down of property, plant and equipment[(a)]	**(1,725,000)**	-
Depletion, depreciation, amortization and accretion[(b)]	**38,614**	78,180
Non-cash interest expense on debentures[(d)]	**10,688**	6,371
Non-cash interest expense on Senior Notes[(f)]	**1,397**	842
Amortization of deferred financing charges[(d)]	**(4,715)**	(3,471)
Currency exchange gain on Senior Notes[(f)]	**589**	1,720
Currency exchange gain on unit distribution[(g)]	**11,543**	10,045
Non-cash general and administrative expenses[(c)]	**(844)**	(443)
Future income tax recovery[(a)]	**112,372**	91,626
Net income (loss) under U.S. GAAP	**(1,343,337)**	159,194
Other comprehensive income		
Net change in cumulative translation adjustment[(g)]	**273,149**	(253,677)
Employee future benefits – actuarial gain (loss)[(h)]	**4,395**	(4,339)
Comprehensive income (loss)	**$ (1,065,793)**	$ (98,822)
Basic		
Net income (loss) per Trust Unit under U.S. GAAP	**$ (8.79)**	$ 1.15
Diluted		
Net income (loss) per Trust Unit under U.S. GAAP	**$ (8.79)**	$ 1.14
Statement of Accumulated Income		
Balance, beginning of year – U.S. GAAP	**564,390**	33,880
Net income (loss) – U.S. GAAP	**(1,343,337)**	159,194
Change in redemption value of Trust Units	**1,595,899**	371,316
Balance, end of year – U.S. GAAP	**816,952**	564,390
Accumulated other comprehensive income (loss)		
Balance, beginning of year – U.S. GAAP	**(210,430)**	47,586
Other comprehensive income	**277,544**	(258,016)
Balance, end of year – U.S. GAAP	**67,114**	(210,430)

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

	December 31, 2008		December 31, 2007	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Property, plant and equipment [(a) (b)]	$ 4,468,505	$ 2,255,407	$ 4,197,506	$ 3,670,688
Deferred charges [(d) (f)]	-	28,740	-	23,390
Non current benefit plan assets [(h)]	-	466	-	393
Future income tax [(a)]	-	-	-	4,986
Liabilities				
Accounts payable and accrued liabilities [(c)]	210,097	209,474	270,240	268,669
Current portion of convertible debentures [(d)]	2,513	2,532	24,273	24,210
Current other benefit plan liability [(h)]	-	223	-	170
7 7/8%Senior notes [(f)]	298,210	303,453	241,148	246,710
Non current portion of convertible debentures [(d)]	825,246	918,197	627,495	671,818
Non current benefit plan liability [(h)]	10,551	11,062	12,168	17,054
Future income tax [(a)]	203,998	-	86,640	-
Temporary equity [(e)]	-	1,562,806	-	2,997,136
Unitholders' Equity				
Unitholders' capital [(e)]	3,897,653	-	3,736,080	-
Equity component of convertible debentures [(d)]	84,100	-	39,537	-
Contributed surplus	6,433	-	-	-
Additional paid-in capital [(d)]	-	9,913	-	9,913
Accumulated income [(g)]	458,884	816,952	246,865	564,390
Accumulated other comprehensive income [(h)(g)]	87,933	67,114	(196,759)	(210,430)

(a) Under Canadian GAAP, Harvest performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, determined using estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate.

Under U.S. GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP impairment test are those in effect at year end. As at December 31, 2008, the application of the ceiling test under U.S. GAAP resulted in a write down of $1,725.0 million. There was no impairment under U.S. GAAP at December 31, 2007.

Under Canadian GAAP as at December 31, 2008, Harvest's carrying value of its net assets exceed its tax bases and accordingly results in recording a future income tax liability. Adjustments under U.S. GAAP result in a large future income tax recovery and elimination of the future income tax liability, as the ceiling test write down significantly lowered Harvest's property, plant, and equipment carrying value under U.S. GAAP and thus decreased the corresponding temporary differences for future tax purposes.

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

Under U.S. GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs as of the date the estimate of reserves is made. In both the current and prior year there were differences in the depletable base and in proved reserves under U.S. GAAP and Canadian GAAP and as a result the difference is realized in the depletion expense.

(c) Under Canadian GAAP, the Trust determines compensation expense and the resulting obligation related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2(h). Under U.S. GAAP, Harvest follows SFAS 123(R) "Share Based Payments" using the modified prospective approach. Under FAS 123(R), expenses and obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting and are revalued at each period end. As a result, general and administrative expense is higher under U.S. GAAP by $0.8 million for the year ended December 31, 2008 (2007 – $0.4 million) with a corresponding increase in accounts payable and accrued liabilities. As at December 31, 2008 the accounts payable and accrued liabilities is lower under U.S. GAAP by $0.6 million (December 31, 2007 – $1.6 million) due to the cumulative effect of this difference.

To the extent compensation costs relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses.

(d) Under Canadian GAAP, Harvest's Convertible Debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs related to the debentures are netted against each respective debt and equity component. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component and the amortization of the issue costs is recorded in the consolidated statements of income with a corresponding credit to the Convertible Debenture liability balance to accrete that balance to the full principal due on maturity.

Under U.S. GAAP, the Convertible Debentures are classified as debt in their entirety, and issue costs are recorded as deferred charges. To the extent that a portion of the issue costs are netted against the respective debt and equity components of the Convertible Debentures under Canadian GAAP there is a difference in the capitalization and amortization of the related deferred charges under U.S. GAAP. The non-cash interest expense recorded under Canadian GAAP is not be recorded under U.S. GAAP.

In addition, Convertible Debentures that are assumed in a business combination are recorded at their fair value at the date of the acquisition as part of the cost of the acquired enterprise. Under U.S. GAAP, if the conversion feature is in-the-money at the acquisition date (a beneficial conversion feature), the feature should be recognized and measured by allocating a portion of the proceeds equal to the intrinsic value of that feature to additional paid-in capital. Where the debenture has a stated redemption date, the corresponding value is recognized as a discount on the convertible debenture balance and accreted from the date of acquisition to the redemption date.

(e) Under Harvest's 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 redemption value of the Trust Units is determined with respect to the trading value of the Trust Units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to accumulated income.

(f) With the adoption of Financial Instruments under Canadian GAAP effective January 1, 2007, issue costs are applied against the 7⅞% Senior Notes balance and accreted into income using the effective interest method. Under U.S. GAAP, these amounts are capitalized as a deferred charge and expensed into income using the effective interest method. There is also a currency exchange impact as the deferred charges and the debt balance of the Senior Notes, which is different under U.S. GAAP, are denominated in U.S. dollars.

(g) With the adoption of the new accounting standards for financial instruments under Canadian GAAP effective January 1, 2007, the cumulative translation adjustment generated upon translating the financial statements of Harvest's downstream operations denominated in a foreign currency previously recognized as a separate component of equity is now recognized in comprehensive income consistent with the treatment under U.S. GAAP. Additionally, under U.S. GAAP, partnership distributions are required to be translated at the historic foreign currency exchange rate in place at the time of initial paid-in capital and any translation gains or losses are recorded in other comprehensive income. Under Canadian GAAP, it is permissible to translate foreign currency denominated partnership distributions at the historic exchange rate that has been proportionately adjusted for the subsequent periods when income has been earned. The effects of the translation are reflected in net income.

(h) At December 31, 2006 the Trust adopted U.S. GAAP SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). Under SFAS 158, the over-funded or under-funded status of our defined benefit postretirement plan are recognized on the balance sheet as an asset or liability and changes in the funded status are recognized through comprehensive income. As a result, for the year ended December 31, 2008 employee future benefits are lower by $4.4 million (2007 – higher by $4.3 million) and a $4.4 million gain was included in other comprehensive income (2007 – loss of $4.3 million included in accumulated other comprehensive income on adoption of SFAS 158). Canadian GAAP currently does not require the Trust to recognize the funding status of the plan on its balance sheet.

New Financial Accounting Pronouncements

(a) In December 2007, FASB issued Statement 141(R), "Business Combinations", which replaces SFAS 141. The standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. SFAS No. 141(R) is applied prospectively to business combinations for which the acquisition date is on or after December 15, 2008. Harvest did not record any business combinations between the effective date and the year ended December 31, 2008. This standard will impact business combinations entered into after December 15, 2008.

(b) In March 2008, FASB issued Statement 161, "Disclosures about Derivative Instruments and Hedging Activities". This statement requires enhanced disclosures about derivative and hedging activity including how and why an entity uses derivative instruments and the derivative instruments effect on an entity's financial position, financial performance, and cash flows. This standard is effective for fiscal years beginning after November 15, 2008. The adoption of this standard will not have a material impact on the consolidated financial statements.

(c) In May 2008, FASB issued FASB Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)". An issuer of a convertible debt instrument within the scope of the staff position is required to separate the instrument into a liability-classified component and an equity-classified component. The staff position is effective for the fiscal year beginning after December 15, 2008. Harvest is currently assessing the impact of the staff position and expects that the guidance will bring U.S. GAAP in line with Canadian GAAP.

(d) In December 2008, the U.S. Securities and Exchange Commission promulgated that effective for fiscal 2009, the year-end proved reserve volumes are to be calculated using a twelve month average price as compared to the current standard which requires prices on the last day of the fiscal year.

24. Subsequent Events

Subsequent to December 31, 2008, Harvest declared a distribution of $0.05 per unit for Unitholders of record on March 23, 2009.

Between January 1, 2009 and February 28, 2009, an additional $292.3 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 22].

25. Related Party Transactions

During the year ended December 31, 2008, Vitol purchased $320.9 million (2007 - $354.8 million) of crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. On December 21, 2008, the director disposed the interest in the company and as such, subsequent to this date, this company no longer represents a related party.

26. Comparatives

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

CORPORATE INFORMATION

DIRECTORS

M. Bruce Chernoff, Chairman (3)
Dale Blue (1)
David Boone (2)
John Brussa (3)
William Friley (3)
Verne Johnson (2)
Hector McFadyen (1)
John Zahary (2)

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

OFFICERS & SENIOR MANAGEMENT

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

Robert Fotheringham, C.A.
Chief Financial Officer

Rob Morgan, P.Eng.
Chief Operating Officer, Upstream

Brad Aldrich
Chief Operating Officer, Downstream

Gary Boukall, P. Geol.
Vice President, Geosciences

Les Hogan
Vice President, Land

Phil Reist, C.A.
Vice President, Controller

Jim Sheasby, P.Eng.
Vice President, Engineering

Neil Sinclair
Vice President, Operations

Dean Beacon
Treasurer

David Rain, C.A.
Corporate Secretary

F. Steven Saunders, C.A.
Director of Taxation and Assistant Corporate Secretary

TRUST UNIT LISTING

Toronto Stock Exchange: HTE.UN
New York Stock Exchange: HTE

Convertible Debenture Listings:

TSX Ticker	Coupon	Conversion	Price Maturity
HTE.DB	9%	$13.85	May 31, 2009
HTE.DB.A	8%	$16.07	September 30, 2009
HTE.DB.B	6.5%	$31.00	December 31, 2010
HTE.DB.D	6.40%	$46.00	October 31, 2012
HTE.DB.E	7.25%	$32.20	September 30, 2013
HTE.DB.F	7.25%	$27.25	February 28, 2014
HTE.DB.G	7.50%	$27.40	May 31, 2015

REGISTRAR AND TRANSFER AGENT

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Calgary, Alberta , Canada T2P 1T1
Telephone: (403) 233-2801

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KPMG LLP

LEGAL COUNSEL

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

RESERVES EVALUATORS

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GLJ Petroleum Consultants Ltd.

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