Harvest OPERATIONS CORP.

Q2 2010

Harvest Operations Corp.

Second Quarter Report

for the three and six month periods ending June 30, 2010

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for three and six month periods ended June 30, 2010.

	Three Months Ended	Six Months Ended
FINANCIAL *($000s except where noted)*	**June 30, 2010**	**June 30, 2010**
Revenue, net [(1)]	**1,024,896**	**1,594,658**
Cash From Operating Activities	**122,335**	**200,469**
Net Income (Loss)[(2)]	**18,203**	**(21,036)**
Bank debt	**182,421**	**182,421**
7⅞% Senior debt	**224,744**	**224,744**
Convertible Debentures[(3)]	**770,780**	**770,780**
Total financial debt[(3)]	**1,177,945**	**1,177,945**
Total Assets	**4,758,472**	**4,758,472**
UPSTREAM OPERATIONS		
Total daily sales volumes (BOE/day)	**49,597**	**49,886**
Operating Netback ($/boe)	**$29.68**	**$32.95**
Capital expenditures	**52,314**	**165,843**
Business and property acquisitions, net	**(726)**	**30,236**
Abandonment and reclamation expenditures	**2,367**	**8,017**
DOWNSTREAM OPERATIONS		
Average daily throughput (bbl/d)	**94,833**	**68,073**
Average Refining Margin (US$/bbl)	**8.56**	**5.86**
Cash capital expenditures	**8,459**	**17,142**

(1) Revenues are net of royalties.

(2) Net Income (Loss) includes a future income tax recovery of $15.1 million and $20.0 million for the three and six months ended June 30, 2010 respectively and an unrealized net gain from risk management activities of $2.2 million and $2.3 million for the three and six months ended June 30, 2010.

(3) Includes current portion of Convertible debentures.

PRESIDENT'S MESSAGE

The second quarter of 2010 marks the first reporting period for Harvest Operations Corp. after an internal reorganization pursuant to which, Harvest Energy Trust and Harvest Operations Corp. were wound up into its sole shareholder, KNOC Canada Ltd., to continue as one corporation under the name Harvest Operations Corp. ("Harvest"). As a growth-oriented, integrated, oil and gas company our direction continues to support Harvest's sustainability through its oil-weighted asset base, significant undeveloped opportunities and the strong technical abilities of our management and employees.

The second quarter saw strong performance of our upstream exploration and production business. Our focus on oil production led to strong financial results when many other producers with a greater focus on natural gas are struggling with low natural gas prices. In the downstream, the second quarter saw much stronger performance than the previous quarter when results were affected by an operational upset and poor refining margins. Corporately, Harvest continued to be active as we grow a solid platform for growth in the Canadian oil industry.

The Cash from Operating Activities was $122.3 million during the quarter. Increased capital spending and improvements in our balance sheet have provided Harvest the operating flexibility to develop opportunities inherent in its asset base.

Upstream

Harvest's production volumes over the second quarter averaged 49,597boe/d. Although unusually wet weather and extended third-party turnarounds had an impact on production volume, our year-to-date performance is as expected and on budget. Second quarter production reflects totaled (bpd).

Investment activity in the second quarter totaled $52.3 million. Harvest drilled 13 gross wells with a success rate of 100%. Investment activity was focused on tying in wells drilled earlier in the first quarter.

Our oil-weighted asset base continues to provide ongoing development opportunities utilizing the latest drilling and completion technology. Harvest is focused on development of high remaining oil in place resource plays throughout our asset base including Cardium and Montney oil in west central Alberta, Viking oil in western Saskatchewan and Slave Point oil and gas in northern Alberta. These development opportunities complement our enhanced oil recovery opportunities in medium and heavy oil pools which together will create a growing production platform with reasonable decline rates that provides sustainability for the future.

Upstream Cash contribution was $122.3 million.

Downstream

North Atlantic, Harvest's downstream refining and marketing business, reported much stronger results than the previous quarter. Average throughput for the quarter was 94,833 bbl/d, an increase over the last quarter due to the completion of maintenance activities during the first quarter.

Refined product mix in the second quarter was weighted to 42% on distillates, 33% to gasoline and 25% to heavy fuel oil. Cash contribution was $28.7 million, as average refining margins were US$8.56/bbl. Refining is a cyclical business that we believe will make a more significant contribution to our cash flow in better markets.

North Atlantic continues to progress the Debottleneck Project. The project consists of 23 individual projects that in combination will enhance the crude capacity by 13%, increase distillate yield to 51% from 43%, and improve the energy efficiency of the refinery by 17%. The Debottleneck Project is expected to continue development through the next year and a half. Capital spent in the quarter amounted to $8.5 million and $17.1 million for the first half of 2010.

Corporate

During the quarter, Harvest successfully renewed our banking credit agreement. Harvest's banking facility was renewed with a $500 million three year revolving extendible credit facility. The credit facility has been significantly reduced as Harvest has less reliance on bank debt as a source of financing due to the equity issues completed early in 2010 and the elimination of the dividend in late 2009. The credit facility also includes an accordion feature whereby Harvest can increase our lending capacity to $1 billion without lender consent. In addition, Harvest's corporate ratings have been upgraded to BB- by Standard and Poor's ("S&P") and Ba2 by Moody's Investor Services.

As mentioned, corporate reorganization was completed in the second quarter with Harvest Energy Trust and Harvest Operations Corp. being wound up into KNOC Canada Ltd., to continue as one corporation under the name Harvest Operations Corp.

Harvest also continues to bolster the technical strength of the organization with a focus on further enhancing the technical capability of the organization. The opportunity for Harvest, with the existing asset base and organization as well as the support to grow, is significant as Harvest looks to provide growth in the years ahead.

On August 6th, 2010, Harvest signed a purchase and sale agreement to purchase certain petroleum and natural gas assets in exchange for $150 million in cash. The purchase of these properties is subject to due diligence and regulatory approval. The acquisition is expected to close by the fourth quarter and will have an effective date of May 1, 2010; upon completion of this purchase, the production from these properties will be included in Harvest's results. These assets have average daily production of 2,300 boe/d and are expected to add 500 boe/d to Harvest's 2010 average daily production.

Harvest continues to be active looking at acquisition and development opportunities that will provide growth for Harvest. Acquisitions will be financed in a manner that maintains a strong balance sheet.

Harvest has consistently maintained a disciplined approach in health, safety and environmental issues and remains committed to operating in a socially responsible manner. Harvest regularly conducts emergency response training, and performs safety and environmental audits of our operating facilities.

In closing, Harvest thanks all of our stakeholders for your support of and interest in our organization.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Operations Corp. should be read in conjunction with the unaudited interim consolidated financial statements of Harvest Operations Corp. for the three and six months ended June 30, 2010. The information and opinions concerning our future outlook are based on information available at August 6, 2010.

On December 22, 2009, KNOC Canada Ltd. ("KNOC Canada"), a wholly owned subsidiary of Korea National Oil Corporation ("KNOC"), purchased all of the issued and outstanding trust units of Harvest Energy Trust (the "Trust) and applied December 31, 2009 as the deemed acquisition date. The acquisition of all the issued and outstanding trust units of the Trust resulted in a change of control in which KNOC Canada became the sole unitholder of the Trust.

On May 1, 2010, an internal reorganization was completed pursuant to which the Trust was dissolved and the Trust's wholly owned subsidiary and manager of the Trust, Harvest Operations Corp., was amalgamated into KNOC Canada to continue as one corporation under the name Harvest Operations Corp ("Harvest" or the "Company"). The carrying values of Harvest's assets and liabilities were determined from the existing carrying values of KNOC Canada's assets and liabilities and therefore reflect the fair values established through the purchase.

KNOC Canada was incorporated on October 9, 2009 and did not have any results from operations or cash flows in the period from October 9, 2009 to the deemed acquisition date of December 31, 2009 aside from capital injections from Korea National Oil Corporation to finance the purchase of the Trust. As KNOC Canada acquired the Trust on the deemed acquisition date of December 31, 2009 the Company's financial statements for the interim period ended June 30, 2010 do not include prior year comparative information. Unaudited pro forma consolidated results of operations have been included in this MD&A to reflect the impact of the acquisition of the Trust, had the acquisition occurred on January 1, 2009.

In this MD&A, reference to "Harvest", "Company", "we", "us" or "our" refers to Harvest Operations Corp. 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 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 and Cash From Operations are also non-GAAP measures and are commonly used for comparative purposes in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations. This information may not be comparable to similar measures by other issuers.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and six months ended June 30, 2010 and the accompanying notes thereto. In the interest of providing our investors 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, 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.

REVIEW OF OVERALL PERFORMANCE

Consolidated cash flow from operating activities was $122.3 million and $200.5 million for the three and six months ended June 30, 2010, representing and increase of $44.1 million over the first quarter of 2010. This increase is primarily due to an increase in contribution from our Downstream operations of $66 million offset by a decrease in contribution from our Upstream operations of $28.8 million.

In January 2010, the Trust received a capital injection from KNOC Canada totaling $465.7 million which was used to fund the repayment of $240.2 million of bank debt, $42.3 million of senior notes and $156.4 million of convertible debentures. As at June 30, 2010, our bank borrowings totaled $182.4 million with $317.6 million of undrawn credit lines available.

Upstream Operations

Upstream operations contributed $122.3 million of cash in the second quarter of 2010 compared with the first quarter contribution of $151.2 million. This decrease is predominantly due to lower commodity prices for oil and natural gas. Second quarter 2010 sales volumes were down marginally by 581 boe/d compared to the first quarter 2010, with the main decreases in natural gas and natural gas liquids as a result of third party plant processing constraints arising from power outages and turnarounds. Second quarter 2010 operating costs totaled $68.3 million, an increase of $4.1 million as compared to $64.3 million incurred in the first quarter of 2010. The increase in operating costs during the second quarter was primarily due to the $5.6 million increase in power and fuel costs, before realized gains from electricity risk management contracts, which resulted from the 97% increase in the average Alberta Power Pool electricity price. Second quarter upstream capital spending of $52.3 million includes the drilling of 13 (net 10.8) wells with a success ratio of 100%.

Downstream Operations

Downstream operations contributed $28.7 million of cash in the second quarter reflecting an average refining margin of US$8.56/bbl. The negative cash flow of $8.6 million for the six months ended June 30, 2010 is a consequence of the unplanned shutdown in the first three months of the year due to a fire in January in the Isomax and surrounding units and the resulting repairs. The average daily throughput for the three and six months ended June 30, 2010 was 94,833 bbl/d and 68,073 bbl/d; the throughput is lower than the capacity of 115,000 bbl/d as a result of the unplanned shutdown in the first three months of the year due to the fire in January; production units resumed operations early in the second quarter following the completion of repairs. Operating costs were $24.5 million in the second quarter of 2010 and were $2.84/bbl of throughput and $49.7 million for the six months ended June 30, 2010 and were $4.03/bbl of throughput. The higher average operating cost per throughput barrel for the six months ended June 30 reflects the impact of the higher maintenance costs and lower throughput in the first quarter. Likewise, purchased energy costs were $3.13/bbl of throughput for the second quarter as compared to $3.45/bbl of throughput for the six months ended June 30, 2010, again reflecting the lower throughput volumes in the first quarter of 2010. Capital expenditures totaled $8.4 million during the second quarter (YTD June 30, 2010- $17.1 million) including $3.7 million related to debottlenecking projects (YTD June 30, 2010- $9.6 million).

UPSTREAM OPERATIONS

Summary of Financial and Operating Results

	Three Months Ended June 30			Six Months Ended June 30		
(in $000s except where noted)	2010	2009 (Pro Forma [2])	Change	2010	2009 (Pro Forma [2])	Change
Revenues	**245,566**	222,115	11%	**517,297**	405,035	28%
Royalties	**(41,200)**	(28,199)	46%	**(82,956)**	(52,728)	57%
Net revenues	**204,366**	193,916	5%	**434,341**	352,307	23%
Operating	**68,328**	61,317	11%	**132,581**	136,652	(3%)
General and administrative	**11,726**	8,874	32%	**24,143**	16,268	48%
Transportation and marketing	**2,068**	3,584	(42%)	**4,275**	6,516	(34%)
Depreciation, depletion and accretion	**110,379**	119,904	(8%)	**221,603**	240,544	(8%)
Earnings (Loss) From Operations[1]	**11,865**	237	4,906%	**51,739**	(47,673)	209%
Capital asset additions (excluding acquisitions)	**52,314**	33,391	57%	**165,843**	142,101	17%
Property and business acquisitions (dispositions), net	**(726)**	(61,403)	99%	**30,236**	(60,728)	150%
Abandonment and reclamation expenditures	**2,367**	1,548	53%	**8,017**	5,014	60%
OPERATING						
Daily sales volumes						
Light / medium oil (bbl/d)	**24,874**	24,316	2%	**24,681**	24,275	2%
Heavy oil (bbl/d)	**9,090**	10,365	(12%)	**9,170**	10,751	(15%)
Natural gas liquids (bbl/d)	**2,334**	2,675	(13%)	**2,574**	2,756	(7%)
Natural gas (mcf/d)	**79,797**	92,335	(14%)	**80,769**	93,870	(14%)
Total	**49,597**	52,745	(6%)	**49,886**	53,427	(7%)

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

(2) The 2009 comparative financial statement values are based on the "proforma" financials of Harvest Operations Corp.; see Note 1 to the June 30, 2010 Consolidated Financial Statements.

Commodity Price Environment

	June 30, 2010	
Benchmarks	Three Months Ended	Six Months Ended
West Texas Intermediate crude oil (US$/bbl)	78.03	78.37
Edmonton light crude oil ($/bbl)	75.14	77.71
Bow River blend crude oil ($/bbl)	66.56	70.05
AECO natural gas daily ($ per mcf)	3.89	4.42
Canadian / U.S. dollar exchange rate	0.973	0.967

The average WTI benchmark price remained essentially flat in the first half of 2010. The average Edmonton light crude oil price (“Edmonton Par”) decreased as a result of third party refinery outages that occurred during the second quarter which resulted in an oversupply of light crude market volumes. The average AECO daily natural gas price for the three months ending June 30, 2010 was lower due to decreased demand resulting from increased storage levels, decreased economic activity and milder than normal weather during the heating season.

	2010	
Differential Benchmarks	Q2	Q1
Bow River Blend differential to Edmonton Par	**$ 8.58**	$ 6.72
Bow River Blend differential as a % of Edmonton Par	**11.0%**	8.4%

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.

Realized Commodity Prices[1]

The following table summarizes our average realized price by product for the three and six months ended June 30, 2010:

	June 30, 2010	
	Three Months Ended	Six Months Ended
Light to medium oil ($/bbl)	68.78	71.53
Heavy oil ($/bbl)	56.51	61.26
Natural gas liquids ($/bbl)	60.68	60.25
Natural gas ($/mcf)	4.17	4.65
Average Realized price ($/boe)	54.41	57.29

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

The decrease in the average realized prices for oil and gas for the three months ended June 30, 2010 are consistent with the decreases in the benchmark prices and the increase in the Bow River Blend differential.

Sales Volumes

The average daily sales volumes by product were as follows:

	June 30, 2010			
	Three Months Ended		Six Months Ended	
	Volume	Weighting	Volume	Weighting
Light / medium oil (bbl/d) [1]	24,874	50%	24,681	50%
Heavy oil (bbl/d)	9,090	18%	9,170	18%
Natural gas liquids (bbl/d)	2,334	5%	2,574	5%
Total liquids (bbl/d)	36,298	73%	36,425	73%
Natural gas (mcf/d)	79,797	27%	80,769	27%
Total oil equivalent (boe/d)	49,597	100%	49,886	100%

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

Average light/medium oil sales were increased during the three months ended June 30, 2010 reflecting new well sales at Hay, Loon Lake and Evi as well as sales from the acquisition of Redwater in March 2010. The increase at Hay was negatively impacted by power and pipeline outages. Our heavy oil sale increases are from new well sales at Lloyd offset by natural production declines, wet weather and a minor turnaround at Hayter East. Average natural gas sales decreased as a result of third party plant processing constraints arising from power outages and turnarounds impacting sales volumes primarily at Chedderville and Crossfield.

Revenues

	June 30, 2010	
($000s)	Three Months Ended	Six Months Ended
Light / medium oil sales	$ 155,678	$ 319,535
Heavy oil sales	46,747	101,678
Natural gas sales	30,253	68,018
Natural gas liquids sales and other	12,888	28,066
Total sales revenue	245,566	517,297
Royalties	(41,200)	(82,956)
Net Revenues	$ 204,366	$ 434,341

Our revenue is impacted by changes to sales volumes, commodity prices and currency exchange rates.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices. For the second quarter of 2010, royalties as a percentage of gross revenue were 16.8% and aggregated to $41.2 million.

Operating Expenses

	June 30, 2010			
	Three Months Ended		Six Months Ended	
($000s)	Total	Per boe	Total	Per boe
Power and fuel	$ 18,671	$ 4.13	$ 31,716	$ 3.51
Well servicing	11,328	2.51	24,245	2.69
Repairs and maintenance	10,199	2.26	20,838	2.31
Lease rentals and property tax	7,713	1.71	15,829	1.75
Processing and other fees	3,064	0.68	6,979	0.77
Labour - internal	5,484	1.22	11,738	1.30
Labour - contract	3,897	0.86	7,917	0.88
Chemicals	4,056	0.90	7,857	0.87
Trucking	2,578	0.57	4,683	0.52
Other	1,338	0.30	779	0.08
Total operating expenses	$ 68,328	$ 15.14	$ 132,581	$ 14.68
Transportation and marketing expense	$ 2,068	$ 0.46	$ 4,275	$ 0.47

Average per boe operating expenses have increased during the three months ended June 30, 2010 due to increasing power and fuel costs. The increase in the power and fuel costs is mainly due to the increase in the Alberta Power Pool electricity price which rose to an average $80.56/MWh during the three months ended June 30, 2010.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 27% of our total operating costs during the three months ended June 30, 2010. Harvest electricity usage in Alberta is exposed to market prices and to mitigate our exposure to electric power price fluctuations, we had electric power price risk management contracts in place. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	June 30, 2010	
($ per boe)	Three Months Ended	Six Months Ended
Electric power and fuel costs	$ 4.13	$ 3.51
Realized gains on electricity risk management contracts	(0.27)	(0.02)
Net electric power and fuel costs	3.86	3.49
Alberta Power Pool electricity price ($ per MWh)	$ 80.56	$ 60.72

Transportation and marketing expense relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and our cost of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our production volumes while the cost per boe typically remains relatively constant.

Operating Netback

	June 30, 2010	
($ per boe)	Three Months Ended	Six Months Ended
Revenues	$ 54.41	$ 57.29
Royalties	(9.13)	(9.19)
Operating expense	(15.14)	(14.68)
Transportation expense	(0.46)	(0.47)
Operating netback [(1)]	$ 29.68	$ 32.95

[(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. The average operating netback for the three months ended June 30, 2010 has decreased due to lower realized commodity prices and higher operating costs.

General and Administrative ("G&A") Expense

($000s except per boe)	June 30, 2010 Three Months Ended	June 30, 2010 Six Months Ended
Total G&A	$ 11,726	$ 24,143
G&A per boe ($/boe)	2.60	2.67

For the three months ended June 30, 2010, G&A expense decreased primarily due to an insurance premium refund of $0.3 million and a rent credit adjustment of $0.2 million. Generally, approximately 80% of our G&A expenses are related to salaries and other employee related costs.

Depletion, Depreciation, Amortization and Accretion Expense ("DDDA&A")

($000s except per boe)	June 30, 2010 Three Months Ended	June 30, 2010 Six Months Ended
Depletion and depreciation	$ 95,193	$ 191,054
Depletion of capitalized asset retirement costs	8,927	18,033
Accretion on asset retirement obligation	6,259	12,516
Total depletion, depreciation and accretion	$ 110,379	$ 221,603
Per boe ($/boe)	$ 24.46	$ 24.54

Our overall DDA&A expense for the three months ended June 30, 2010 was relatively unchanged from the first quarter of 2010 largely as production volumes remained constant throughout the first half of the year.

Capital Expenditures

($000s)	June 30, 2010 Three Months Ended	June 30, 2010 Six Months Ended
Land and undeveloped lease rentals	$ 10,495	$ 10,665
Geological and geophysical	2,879	11,429
Drilling and completion	19,748	92,687
Well equipment, pipelines and facilities	16,225	45,730
Capitalized G&A expenses	2,835	5,011
Furniture, leaseholds and office equipment	132	321
Total development capital expenditures excluding acquisitions	$ 52,314	$ 165,843

Capital expenditures are down during the second quarter of 2010 as a result of drilling 13 gross wells (10.8 net) compared to drilling 80 gross wells (65.9 net) in the first quarter of 2010. The majority of the 2010 second quarter drilling activity consisted of three gross (3.0 net) wells at Loydminister Heavy Oil ($2.6 million), three gross (2.5 net) wells at SE Saskatchewan ($2.8 million), one gross (0.5 net) well at SE Alberta ($1.7 million), one gross (1.0 net) well at Crossfield ($4.9 million), two gross (1.3 net) wells at Rimbey/Markerville ($2.2 million) and two gross (1.5 net) wells at Red Earth ($5.5 million).

During the second quarter of 2010 Harvest acquired lands at Red Earth ($6.2 million) and West Central Alberta ($3.9 million). These lands were acquired for future development and exploration purposes.

In the first half of 2010, Harvest had a 100% success rate for all wells drilled. The following summarizes Harvest's participation in gross and net wells drilled during the three and six month ending June 30:

	June 30, 2010			
	Three Months Ended		Six Months Ended	
Area	Gross(1)	Net	Gross(2)	Net
Hay River	0.0	0.0	8.0	8.0
SE Alberta	1.0	0.5	7.0	3.6
Rimbey/Markerville	2.0	1.3	9.0	4.6
SE Saskatchewan	3.0	2.5	10.0	9.5
Red Earth	2.0	1.5	18.0	14.7
Suffield	0.0	0.0	5.0	5.0
Lloydminster Heavy Oil	3.0	3.0	23.0	21.0
Crossfield	1.0	1.0	3.0	2.9
Kindersley	0.0	0.0	6.0	4.7
Other Areas	1.0	1.0	4.0	2.7
Total wells	13.0	10.8	93.0	76.7

(1) Excludes 3 additional wells that we have royalties interest in.
(2) Excludes 4 additional wells that we have royalties interest in.

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 $4.0 million during the second quarter of 2010 as a result of accretion expense of $6.3 million and new liabilities recorded of $0.1 million, offset by $2.4 million of asset retirement liabilities settled.

DOWNSTREAM OPERATIONS

Summary of Financial and Operational Results

	Three Months Ended June 30			Six Months Ended June 30		
(in $000's except where noted below)	**2010**	2009 (Pro Forma[5])	Change	**2010**	2009 (Pro Forma[5])	Change
Revenues	**820,530**	369,081	122%	**1,160,317**	941,785	23%
Purchased feedstock for processing and products purchased for resale [(4)]	**731,778**	322,855	127%	**1,062,351**	704,692	51%
Gross margin[(1)]	**88,752**	46,226	92%	**97,966**	237,093	(59%)
Costs and expenses						
Operating	**30,278**	26,974	12%	**60,037**	50,940	18%
Purchased energy	**27,040**	11,161	142%	**42,470**	27,768	53%
Marketing	**2,364**	3,122	(24%)	**3,315**	6,101	(46%)
General and administrative	**441**	520	(15%)	**882**	875	1%
Depreciation and amortization	**20,179**	22,771	(11%)	**40,624**	47,096	(14%)
Earnings (Loss) From Operations[(1)]	**8,450**	(18,322)	146%	**(49,362)**	104,313	(147%)
Capital asset additions	**8,459**	19,929	(58%)	**17,142**	26,833	(36%)
Feedstock volume (bbl/day)[(2)]	**94,833**	52,808	80%	**68,073**	78,410	(13%)
Yield (000's barrels)						
Gasoline and related products	**2,949**	1,372	115%	**3,833**	4,693	(18%)
Ultra low sulphur diesel and jet fuel	**3,548**	1,830	94%	**4,629**	5,324	(13%)
High sulphur fuel oil	**2,312**	1,183	95%	**3,562**	3,553	-
Total	**8,809**	4,385	101%	**12,024**	13,570	(11%)
Average refining gross margin (US$/bbl)[(3)]	**8.56**	6.50	32%	**5.86**	12.51	(53%)

(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 gross margin is calculated based on per barrel of feedstock throughput.
(4) Purchased feedstock for processing and products purchased for resale includes inventory write-downs, net of reversals, of $2.2 million and $3.3 million for the three and six months ended June 30, 2010, respectively.
(5) The 2009 comparative financial statement values are based on the "pro-forma" financials of the Downstream operations of Harvest Operations Corp.; see Note 1 to the June 30, 2010 Consolidated Financial Statements

Overview of Downstream Operations

Our Downstream operations are composed of a 115,000 bpd 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 composed of branded and unbranded retail and wholesale distribution and sales of gasoline, diesel, jet and other transportation fuels, as well as home heating fuels and the revenues from our marine services businesses.

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 and other feedstocks purchased as well as the yield of refined products from various feedstocks. We continuously evaluate the market and relative refinery values of several different crude oils and vacuum gas oils ("VGO") to determine the optimal feedstock mix. We analyze the refining margin for each refined product as well as our sales revenue relative to refined product benchmark prices 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 for reporting.

In 2010, we purchased substantially all of our refinery feedstock and sold our distillates, gasoline products and high sulphur fuel oil ("HSFO"), 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 ("SOA"). Further details on the SOA are included under "Liquidity and Capital Resources".

The SOA 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 the 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.

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:

	June 30, 2010	
	Three Months Ended	**Six Months Ended**
WTI crude oil (US$/bbl)	78.03	78.37
Brent crude oil (US$/bbl)	79.51	78.40
Basrah Official Sales Price Discount (US$/bbl)	(1.58)	(2.90)
RBOB gasoline (US$/bbl/gallon)	91.07/2.17	89.63/2.13
Heating Oil (US$/bbl/gallon)	88.55/2.11	87.27/2.08
High Sulphur Fuel Oil (US$/bbl)	69.25	69.99
Canadian / U.S. dollar exchange rate	0.973	0.967

The RBOB Gasoline crack spread averaged US$13.04/bbl in the second quarter of 2010 and US$11.26/bbl for the six months ended June 30, 2010. For the three and six months ended June 30, the Heating Oil crack spread averaged US$10.52/bbl and US$8.90/bbl, respectively. The HSFO benchmark price averaged US$8.78/bbl less than WTI in the second quarter of 2010 and US$8.38/bbl less than WTI in the six months ended June 30, 2010.

During the three months ended June 30, 2010, the Canadian/U.S. dollar exchange rate remained strong. The strengthening of the Canadian dollar in 2010 has slightly decreased the contribution from our Downstream operations as substantially all of its gross margin, cost of purchased energy and marketing expense are denominated in U.S. dollars.

Summary of Gross Margin

The following table summarizes our Downstream gross margin for the three and six months ended June 30, 2010 segregated between refining activities and petroleum marketing and other related businesses.

	June 30, 2010					
	Three Months Ended			**Six Months Ended**		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Sales revenue(1)	791,287	150,003	820,530	1,102,327	266,436	1,160,317
Cost of feedstock for processing and products for resale(1)	715,385	137,153	731,778	1,027,708	243,089	1,062,351
Gross margin(2)	75,902	12,850	88,752	74,619	23,347	97,966
Average refining gross margin (US$/bbl)	8.56			5.86		

(1) Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $120.8 million and $208.5 million for the three and six months ended June 30, 2010, respectively, 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.

For the three months ended June 30, 2010, our refining gross margin of $75.9 million reflects the return to normal operations after an unplanned shutdown in the first quarter as a consequence of a fire. An insurance claim will be submitted to the Company's insurers relating to the cost of the business interruption loss incurred in the First Quarter due to the unplanned shutdown. The contribution from the marketing operations is fairly consistent from month to month but may be impacted by seasonal demand and other factors. The unplanned shutdown of the refinery units in early January of 2010 had a negative impact on the revenue from the marine operations during the first three months of 2010, however, revenues improved in the second quarter with the start-up of the refinery units in early April.

Refinery Sales Revenue

A comparison of our refinery yield, product pricing and revenue for the three and six months ended June 30, 2010 is presented below:

	June 30, 2010					
	Three Months Ended			Six Months Ended		
	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	275,023	3,025	88.46/2.10	360,387	3,972	87.74/2.09
Distillates	351,691	3,838	89.16/2.12	463,998	5,053	88.80/2.11
High sulphur fuel oil	164,573	2,331	68.70	277,942	3,861	69.61
	791,287	9,194	83.74	1,102,327	12,886	82.72
Inventory adjustment		(385)			(862)	
Total production		8,809			12,024	
Yield (as a % of Feedstock) (2)		102%			98%	

(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.

For the three months ended June 30, 2010, our refinery yield was comprised of 34% gasoline products, 40% distillates and 26% HSFO and for the six months ended June 30, 2010 our yield was comprised of 32%, 38% and 30% for the same products respectively. The change in product yields is a consequence of the start-up of production units and the return to normal operations following the completion of repairs for an unplanned shutdown in early January in the first quarter.

In the second quarter of 2010, our average refined product sales price was US$83.74/bbl, a premium of US$5.71/bbl over WTI. For the six months ended June 30, 2010 our average refined product sales price was US$82.72/bbl, a premium of US$4.35/bbl over WTI.

During the second quarter of 2010, the average sales price of our gasoline products of US$88.46/bbl was a US$10.43/bbl premium to the average WTI price as compared to the RBOB benchmark crack spread of US$13.04/bbl. The US$2.61/bbl differential between our gasoline products crack spread and the benchmark crack spread is a consequence of transportation costs and timing of sales under the SOA.

For the six months ended June 30, 2010 our average sales price for gasoline products of US$87.74 was a US$9.37/bbl premium to the average WTI price as compared to the RBOB benchmark crack spread of US$11.26/bbl. This US$1.89/bbl differential between our gasoline products crack spread and the benchmark crack spread is a consequence of transportation costs, the timing of sales under the SOA and limited sales during the first quarter.

During the second quarter of 2010, the average sales price for our distillate products of US$89.16/bbl was a US$11.13/bbl premium to the average WTI price as compared to a US$10.52/bbl premium for the Heating Oil benchmark price over WTI. The US$0.61/bbl differential between our distillate products crack spread and the benchmark Heating Oil crack spread reflects the higher quality distillate products produced and sold by our refinery as compared to the quality of the Heating Oil benchmark pricing. The distillate premium realized by our refinery is also impacted by transportation costs and the timing of sales under the SOA.

During the six months ended June 30, 2010 the average sales price for our distillate products of US$88.80/bbl was a US$10.43/bbl premium to the average WTI price as compared to a US$8.90 premium for the Heating Oil benchmark price over WTI. The US$1.53/bbl differential between our distillate products crack spread and the Heating Oil benchmark crack spread reflects the higher quality distillate products produced and sold by our refinery as compared to the quality of the Heating Oil benchmark pricing and the timing of sales under the SOA, offset by transportation costs. In addition, sales of distillate products were limited in the first quarter as a result of the unplanned shutdown of the refinery units.

During the second quarter of 2010, the average sales price of our HSFO of US$68.70/bbl was a US$9.33/bbl discount to the average WTI price as compared to an US$8.78/bbl discount for the HSFO benchmark pricing from WTI. The higher HSFO discounts realized by the refinery for the second quarter are a result of transportation costs and timing of sales under the SOA.

For the six months ended June 30, 2010 the average sales price of our HSFO of US$69.61/bbl was a US$8.76/bbl discount to WTI as compared to the HSFO benchmark pricing discount of US$8.38/bbl. The higher HSFO discounts realized by the refinery for the six months ended June 30 are a result of transportation costs, timing of sales under the SOA and limited sales of HSFO in the first quarter as a consequence of the fire in January.

Refinery Feedstock

The volatility of WTI prices from month to month makes it difficult to compare the financial impact of specific crude types when our consumption of crude types varies from month to month and costs are aggregated over the quarter. Further, our refinery competes for international waterborne crude oil and VGO's and the WTI benchmark price reflects a land-locked North American price with limited access to the international markets.

The cost of our feedstock reflects numerous factors beyond WTI prices, 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 operational hedging of the WTI component of our feedstock costs through the SOA, the ten day delay in pricing pursuant to the SOA and for Iraqi crude oil purchased, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. The OSP discount is set on a monthly basis and announced for North American deliveries. Prior to April of 2010, the OSP discount was set relative to WTI, however, in April of 2010, the Oil Marketing Company of the Republic of Iraq changed the OSP basis from WTI to Argus Sour Crude Index ('ASCI") which represents the daily value of US Gulf Coast medium sour crude based on physical spot market transactions.

A further complication to the comparison of the financial impact of our feedstock costs to the benchmark pricing is the operational impact of the fire on the Isomax and surrounding units in January of 2010. As a consequence of the fire, the affected units were shutdown for repairs for approximately ten weeks. As well, remaining production units were shutdown at the end of January as a result of unfavorable economics. Operations resumed in early April 2010 and second quarter results reflect fairly normal refinery operations.

A comparison of crude oil and VGO feedstock processed for the three and six months ended June 30, 2010 is presented below:

	June 30, 2010					
	Three Months Ended			Six Months Ended		
	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	490,136	6,539	72.93	669,592	8,788	73.68
Russian	92,971	1,368	66.13	205,554	2,726	72.92
Venezuelan	15,897	194	79.73	20,381	256	76.99
Crude Oil Feedstock	599,004	8,101	71.95	895,527	11,770	73.57
Vacuum Gas Oil	43,209	529	79.48	45,070	551	79.10
	642,213	8,630	72.41	940,597	12,321	73.82
Net inventory adjustment [(2)]	21,398			17,483		
Additives and blendstocks	49,541			66,314		
Inventory write-down (recovery) [(3)]	2,233			3,314		
	715,385			1,027,708		

(1) Cost of feedstock includes all costs of transporting the crude oil to the 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.

Throughput in the second quarter of 2010 was 94,833 bbl/d and for the six months ended June 30, 2010 throughput averaged 68,073 bbl/d. Average daily throughput in 2010 is less than the nameplate capacity of 115,000 bbl/d for our refinery as a result of the unplanned shutdown of the refinery units in January month. Operations resumed in the second quarter following the start-up of the production units in early April. Daily average throughput continued to be slightly lower than capacity during the second quarter as a result of ongoing maintenance.

As is normal business practice, the WTI component of our feedstock cost is operationally hedged under the SOA with Vitol. When we commit to crude oil purchases, Vitol sells a forward WTI price contract for the next contract month, which results in price fluctuations subsequent to our purchase commitment being offset by the price volatility of the forward price curve. If the timing between processing the crude oil and the expiration of the forward contract are not aligned, the volume of the forward contract relating to unprocessed crude oil is rolled to the next contract month. This practice results in better matching of our refined product sales prices with our cost of feedstock. The persistent contango shape of the NYMEX WTI futures results in operational hedging gains from the rolling forward of these price contracts, which reduce our feedstock costs in the month the feedstock is processed. During the three and six months ended June 30, 2010, this operational hedging resulted in reductions to the cost of our feedstock of US$15.3 million and US$18.4 million, respectively.

The cost of our crude oil feedstock averaged US$71.95/bbl during the second quarter of 2010 representing a US$6.08/bbl discount to WTI. The US$6.08/bbl discount is comprised of a US$3.10/bbl quality discount, plus a US$1.73/bbl operational hedging gain and a US$1.25/bbl credit relating to timing under the SOA with Vitol. The cost of our crude oil feedstock averaged US$73.57/bbl for the six months ended June 30, 2010 representing a US$4.80/bbl discount to WTI. The US$4.80/bbl discount is comprised of a US$2.43/bbl quality discount, plus a US$1.42 operational hedging gain and a US$0.95/bbl credit relating to timing under the SOA with Vitol.

The average cost of purchased VGO during the second quarter of 2010 was US$79.48/bbl representing a premium of US$1.45/bbl relative to the WTI. The premium paid in the second quarter of 2010 is comprised of a US$5.53/bbl pricing premium relative to WTI offset by a US$1.66/bbl credit relating to timing under the SOA with Vitol and a US$2.42/bbl operational hedging gain. The average cost of purchased VGO for the six months ended June 30, 2010 was US$79.10/bbl representing a premium of US$0.73/bbl relative to the WTI. The premium paid is comprised of a US$5.18/bbl pricing premium relative to WTI offset by a US$2.87/bbl operational hedging gain and a US$1.58/bbl credit relating to timing under the SOA with Vitol.

Included in the additives and blendstocks for the three and six months ended June 30, 2010 is the cost of products purchased for further refining into finished products and products purchased for resale to the local market.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the three and six months ended June 30, 2010:

	June 30, 2010					
	Three Months Ended			Six Months Ended		
(000's of Cdn dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Operating costs	24,509	5,769	30,278	49,653	10,384	60,037
Purchased energy	27,040	-	27,040	42,470	-	42,470
	51,549	5,769	57,318	92,123	10,384	102,507

During the three and six months ended June 30, 2010, refining operating costs were $2.84/bbl and $4.03/bbl of throughput, respectively. The higher operating costs per barrel for the six months period includes the higher maintenance costs related to the fire repairs combined with a reduction in throughput. Included in the marketing division operating expenses for the second quarter are additional maintenance costs incurred for the marine operations.

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 three months ended June 30, 2010 was $3.13/bbl of throughput and for the six months ended June 30, 2010 our purchased energy was $3.45/bbl of throughput. In the second quarter of 2010, we purchased approximately 343,000 barrels of fuel oil at an average price of US$69.76/bbl. Likewise in the six months ended June 30, 2010 we purchased approximately 520,000 barrels at an average price of US$72.09/bbl.

Marketing Expense and Other

During the three months ended June 30, 2010, marketing expense was comprised of $0.3 million of marketing fees (six months ended June 30, 2010 - $0.3 million), based on $0.02/bbl to acquire feedstock and $2.1 million (six months ended June 30, 2010 - $3.0 million) of TVM charges both pursuant to the terms of the SOA. The higher TVM charge in the second quarter is mainly the result of increased purchased feedstock volume. As at June 30, 2010, Harvest had commitments totaling approximately $502.5 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the three and six months ended June 30, 2010 totaled $8.4 million and $17.1 million, respectively, relating to various capital improvement projects including $3.7 million of expenditures in the second quarter for the debottlenecking projects and $9.6 million of expenditures related to the debottlenecking projects for the six months ended June 30.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the three and six months ended June 30, 2010:

	June 30, 2010					
	Three Months Ended			Six Months Ended		
(000's of Cdn dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Tangible assets	19,340	839	20,179	38,913	1,711	40,624

The process units are amortized over an average useful life of 20 to 30 years.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Harvest employs an integrated approach to cash flow risk management strategies whereby 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 2010 cash flow at risk is comprised of approximately 32,000 bbls/d of refined product price exposure, 57,000 bbls/d of refined product crack spread exposure and 68,000 mcf/d of net western Canadian natural gas price exposure.

The details of our commodity price contracts outstanding at June 30, 2010 are included in the notes to our consolidated financial statements which are also filed on SEDAR at www.sedar.com.

For the three months ended June 30, 2010, Harvest had electricity price swap contracts in place for 25.0 MWh from January to December 2010 at an average price of $59.22 per MWh as well as electricity price swap contracts for 5.0 MWh from January to December 2011 at an average price of $45.85 per MWh. Our electricity price contracts realized gains of $1.2 million and $0.2 million for the three and six months ended June 30, 2010, respectively.

As at June 30, 2010, the mark-to-market value on our electric power contracts aggregated to $0.3 million.

Interest Expense

	June 30, 2010	
($000s)	Three Months Ended	Six Months Ended
Interest on short term debt		
Bank loan	$ -	$ 1,370
Convertible debentures	312	93
Senior notes	-	30
Total interest on short term debt	312	1,493
Interest on long term debt		
Bank loan	1,524	1,524
Convertible debentures	12,504	26,214
Senior notes	3,950	8,326
Total interest expense on long term debt	$ 17,978	$ 36,064
Total interest expense	$ 18,290	$ 37,557

Total Interest expense for three and six months ended June 30, 2010 including the amortization of related financing costs was $18.3 million and $37.6 million, respectively.

Interest expense on our bank loan for the three months ended June 30, 2010 reflects amended terms on our revolving credit facility that was amended on April 30, 2010 whereby the floating rate increased from 70 basis points over bankers' acceptances for Canadian dollar borrowings to 200 basis points. The Revolving Credit Facility was required to be amended as the KNOC Canada acquisition triggered the "change of control" provision. During the three months ended June 30, 2010, interest charges on bank loans reflected an average interest rate of 1.95%. The increased floating rate in the three months ended June 30, 2010 was offset against a lower balance outstanding throughout the second quarter as a result of the $465.7 million equity issuance to KNOC Canada in January 2010 that was partially used to pay down the Bank Loan.

During the first quarter of 2010, the KNOC Canada acquisition triggered the "change of control" provisions included within the convertible debentures and the 7⅞% senior notes indentures which required the Company to make an offer to purchase these instruments for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest. By March 4, 2010 all of the redemption offers had expired and $156.4 million principal amount of convertible debentures and US$40.4 milion principal amount of 7⅞% senior notes were redeemed; see the Liquidity and Capital Resources section below for further details related to the redemptions. This reduction of outstanding principal amount has led to a decrease in interest expense on the convertible debentures and senior notes for the three months ended June 30, 2010.

The bank loan, convertible debentures and 7⅞% senior notes are recorded at amortized cost and as such interest is calculated using the effective interest method. Therefore, total interest includes non-cash interest income of $3.8 million and $4.7 million for the three and six months ended June 30, 2010 relating to the amortization of the premium on the convertible debentures and 7⅞% senior notes and the fees incurred on the credit facility.

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 $5.6 million and $5.2 million for the three and six months ended June 30, 2010 respectively, have resulted from the settlement of U.S. dollar denominated transactions. At June 30, 2010 the Canadian dollar has weakened compared to March 31, 2010 and December 31, 2009 resulting in an unrealized foreign exchange gain of $3.0 million and loss of $3.4 million for the three and six months ended June 30, 2010.

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 the three and six months ended June 30, 2010, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $46.9 million and $20.0 million net cumulative translation gain 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

As KNOC Canada acquired the Trust on the deemed acquisition date of December 31, 2009, the opening future income tax liability is calculated as part of the purchase price allocation recorded at that date. The opening future income tax liability of $211.2 million represents a tax liability driven by the excess book over tax value of net assets. For six months ended June 30, 2010, we have recorded a future income tax reduction of $20.0 million to reflect the changes in the temporary differences. At the end of the six months ended June 30 2010, Harvest had a net future income tax liability on the balance sheet of $191.1 million comprised of a $89.0 million future income tax liability for the downstream corporate entities and a future income tax liability of $102.1 million for the upstream entities.

Income Tax 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. Harvest has filed a Notice of Objection with the CRA and filed a Notice of Appeal with the Tax Court. The CRA and Harvest have now attended the examinations for discovery in early April 2010; the undertakings, which are mutual requests for additional information, have been completed on both sides.

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. As at June 30, 2010, we also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

	Maturity				
($000s)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(1)	$ 1,163,328	$ 23,810	$ 329,900	$ 573,019	$ 236,599
Interest on long-term debt(1)	234,308	38,771	128,242	60,003	7,292
Operating and premise leases	32,264	3,769	14,630	12,419	1,446
Purchase commitments(2)	36,099	34,282	1,817	-	-
Asset retirement obligations(3)	1,211,209	16,186	28,189	26,335	1,140,499
Transportation (4)	6,202	2,903	3,094	205	-
Pension contributions(5)	24,564	2,800	8,448	8,789	4,527
Feedstock commitments	502,471	502,471	-	-	-
Total	$ 3,210,445	$ 624,992	$ 514,320	$ 680,770	$ 1,390,363

(1) Assumes constant foreign exchange rate.
(2) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(3) Represents the undiscounted obligation by period.
(4) Relates to firm transportation commitment on the Nova pipeline.
(5) 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. Refer to Note 18 of the unaudited interim June 30, 2010 financial statements for commitments related to subsequent acquisitions.

Off Balance Sheet Arrangement

As of June 30, 2010, we have no off balance sheet arrangements in place.

LIQUIDITY AND CAPITAL RESOURCES

Harvest is an integrated company 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 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 incremental debt and capital injections from KNOC. Should incremental debt not be available to us through debt capital markets, our ability to make the necessary expenditures to maintain or expand our assets may be impaired. 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 the latter part of 2009 and into the first quarter of 2010 we had seen an improvement in the price of oil and in the liquidity of the debt capital markets. During the second quarter of 2010, the global economic recovery has somewhat stabilized which resulted in a decrease in oil prices. In the first quarter, the state of the bank credit markets had also improved, supporting the renewal of our revolving credit facility at the end of April. In addition both Standard and Poor's Ratings Services ("S&P") and Moody's Investors Service upgraded our corporate ratings to "BB-" and "Ba2", respectively, and the 7⅞% senior notes rating to "BB- and "Ba1", respectively. 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, as further discussed below, it is anticipated that we will have enough liquidity to fund future operations and forecasted capital expenditures.

During the three and six months ended June 30, 2010, cash flow from operating activities was $122.3 million and $200.5 million, respectively. Cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures totaled $127.7 million and $217.6 million for the three and six months ended June 30, 2010 respectively. In January 2010, the Trust received a capital injection from KNOC Canada totaling $465.7 million which was used to fund the repayment of $240.2 million of bank debt, $42.3 million of senior notes and $156.4 million of convertible debentures. We required an additional $60.0 million and $213.2 million for capital expenditures and net asset acquisition activity for the three and six months ended June 30, 2010, respectively. As at June 30, 2010, our bank borrowings totaled $182.4 million with $317.6 million of undrawn credit lines available.

The following table summarizes our capital structure as at June 30, 2010 and December 31, 2009 as well as provides the key financial ratios contained in our revolving credit facility. For a complete description of our revolving credit facility, 7⅞% senior notes and convertible debentures, see Notes 8, 9 and 10, respectively, to our interim consolidated financial statements for the period ended June 30, 2010 filed on SEDAR at www.sedar.com.

SUMMARY OF CAPITALIZATION		
(in millions)	**June 30, 2010**	December 31, 2009
Revolving credit facility	**$ 182.4**	$ 428.0
7⅞% senior notes due 2011 (US$209.6 million) [(1)]	**223.1**	262.8
Convertible debentures, at principal amount	**757.8**	914.2
Total Debt	**1,163.3**	1,605.0
Shareholder's Equity		
288,836,653 issued at June 30, 2010	**2,887.3**	
242,268,801 issued at December 31, 2009		2,422.7
TOTAL CAPITALIZATION	**$ 4,050.6**	$ 4,027.7

FINANCIAL RATIOS		
Secured Debt to Annualized EBITDA (2)	**0.4**	0.7
Total Debt to Annualized EBITDA (2) (3)	**2.3**	2.7
Secured Debt to Total Capitalization	**5%**	11%
Senior Debt to Total Capitalization	**29%**	40%

(1) Face value converted at the period end exchange rate.
(2) Annualized Earnings Before Interest, Taxes, Depreciation and Amortization based on twelve month rolling average.
(3) "Total Debt" includes the convertible debentures in 2010 due to the economic elimination of the conversion feature subsequent to the acquisition of Harvest Energy Trust by KNOC Canada.

KNOC Canada's acquisition of Harvest Energy Trust triggered the "change of control" provisions included within the convertible debentures and the 7⅞% senior notes indentures, as well as within our $1.6 billion extendible revolving credit facility. These change of control provisions resulted in the renewal of our credit facility on May 1, 2010 and the redemption of some of our convertible debentures and 7⅞% senior notes in the first quarter.

Credit Facility

As a result of this change of control provision, at the end of 2009 an amended extendible revolving credit facility ("the Facility") agreement was reached with eight of the original fourteen lenders, maturing April 30, 2010 for a new commitment level of $600 million. On April 30, 2010 the Facility agreement was amended and extended for three years, maturing April 30, 2013 and the capacity was reduced from $600 million to $500 million. All invited lenders with the exception of one approved the amended and extended Facility, reducing the number of lenders from eight to seven. We continue to pay a floating interest rate, which is determined by a grid based on our secured debt (excluding 7⅞% senior notes and convertible debentures) to earnings before interest, taxes, depletion, amortizations and other non-cash items ("EBITDA"). The minimum rate charged in the grid is 200 bps over bankers' acceptance rates as long as our secured debt to EBITDA ratio remains below or equal to one; we expect to remain below this threshold for the immediate future. Under the new capacity limit of $500 million, we had unutilized borrowing capacity of $317.6 million based on our drawn amount as at June 30, 2010 of $182.4 million. We have the option to increase the capacity limit from $500 million to $1.0 billion, without lender consent, by utilizing the accordion feature and securing additional capacity from an existing or new lender(s). The financial covenants remain the same as in the past and are listed as:

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

Convertible Debentures

The "change of control" provision included within the convertible debentures' indetnures required Harvest to make an offer to purchase 100% of the outstanding convertible debentures for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest. Harvest made these offers on January 20, 2010 and by March 4th all of the offers had expired and the following redemptions were made:

- 6.5% Debentures due 2010 – $13.3 million principal amount tendered leaving a principal balance of $23.8 million outstanding
- 6.4% Debenture due 2012 – $67.8 million principal amount tendered leaving a principal balance of $106.8 million outstanding
- 7.25% Debentures due 2013 – $48.7 million principal amount tendered leaving a principal balance of $330.5 million outstanding
- 7.25% Debentures due 2014 – $13.2 million principal amount tendered leaving a principal balance of $60.1 million outstanding
- 7.5% Debentures due 2015 – $13.4 million principal amount tendered leaving a principal balance of $236.6 million outstanding

As a result of the KNOC Canada acquisition, the debentures are no longer convertible into Units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. As every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option.

7⅞% Senior Notes

In October 2004, the Trust issued US$250 million of principal amount 7⅞% senior notes and $209.6 million remain outstanding at June 30, 2010. These 7⅞% senior notes are unsecured, require semi-annual payments of interest and mature on October 15, 2011.

Similar to the convertible debentures, our 7⅞% senior notes indenture Change of Control provision required Harvest to make an offer to purchase 100% of the outstanding 7⅞% senior notes for cash consideration of 101% of the principal amount plus any accrued and unpaid interest. Harvest made this offer on January 20, 2010 and on February 16, 2010 the offer expired and US$40,434,000 principal amount was tendered, leaving a principal balance of US$209,566,000 outstanding. Harvest may call the remaining 7⅞% senior notes for redemption at a price of 101.969% of the principal amount plus any accrued and unpaid interest to the redemption date and effective October 15, 2010 and thereafter, at a price of 100% of the principal amount plus any accrued and unpaid interest to the redemption date.

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 December 31, 2009, 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. This covenant is recalculated on an annual basis, therefore, as at June 30, 2010 the calculation at December 31, 2009 remains in effect.

Supply and Offtake Agreement

Concurrent with the acquisition of North Atlantic Refining Limited Partnership ("North Atlantic") by Harvest in 2006, North Atlantic entered into a supply and offtake agreement (the "SOA") with Vitol Refining S.A. ("Vitol"), and this agreement was amended and extended October 12, 2009; effective November 1, 2009. The SOA provides that the ownership of substantially all crude oil and other feed stocks and refined product inventories at the refinery be retained by Vitol and that Vitol be granted the exclusive right and obligation to provide crude oil feedstock and other feed stocks for delivery to the refinery as well as the exclusive right and obligation to purchase virtually all refined products produced by the refinery for export. The SOA also provides that Vitol will receive a time value of money amount (the "TVM") reflecting the cost of financing the working capital associated with the purchase of crude oil and other feed stocks and sale of refined products, as the SOA requires that Vitol retain ownership of the crude oil and other feed stocks until delivered through the inlet flange to the refinery as well as immediately take title to the refined products as they are delivered by the refinery through the inlet flange to designated storage tanks. Further, the SOA provides North Atlantic with the opportunity to share the incremental profits and losses resulting from the sale of products beyond the U.S. east coast markets.

Pursuant to the SOA, we, in consultation with Vitol, request a certain slate of crude oil and other feed stocks and Vitol is obligated to provide the feed stocks in accordance with the request. The SOA includes a feedstock transfer pricing formula that aggregates the pricing for the feed stocks purchased as correlated to published future contract settlement prices, the cost of transportation from the source of supply to the refinery and the settlement cost or proceeds for related operational price risk management contracts plus a marketing fee. The purpose of these operational price risk management contracts is to convert the fixed price of crude oil and other feedstock purchases to floating prices for the period from the purchase date through to the date the refined products are sold to North Atlantic to allow "matching" of feedstock purchases to refined product sales, thereby mitigating the gross margin risk between the time feed stocks are purchased and the time refined products are sold.

The SOA requires that Vitol purchase and lift all refined products produced by the refinery, except for certain excluded refined products to be marketed by North Atlantic in the local Newfoundland market, and provides a product purchase pricing formula that aggregates a price based on the current Boston and New York City markets less the costs of transportation, insurance, port fees, inspection charges and similar costs incurred by Vitol, plus the TVM component.

The SOA is effective until November 1, 2011 and may be terminated by either party at any time thereafter by providing notice of termination no later than six months prior to the desired termination date or if the refinery is sold in an arm's length transaction, upon 30 days notice prior to the desired termination date. Further, the SOA may be terminated upon the continuation for more than 180 days of a delay in performance due to force majeure but prior to the recommencing of performance. Upon termination of the entire agreement or the right and obligation to provide feed stocks, North Atlantic will be required to purchase the related feed stocks and refined product inventories, respectively, at the prevailing market prices.

Vitol is an indirect wholly-owned subsidiary of the Vitol Group, a privately owned worldwide marketer of crude oil providing oil trading and marketing services to upstream producers through to downstream retailers of petroleum products. The Vitol Group is one of the largest independent gasoline traders in the world. With headquarters in Rotterdam, the Netherlands and Geneva Switzerland, with trading entities in Houston, London, Bahrain and Singapore the Vitol Group has 24 hour coverage of all the world's oil markets. In the crude oil sector, the Vitol Group has developed a worldwide reputation as a reliable business partner.

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. The amendments made in 2009 to the SOA increased the amount of working capital financing available, reduced the cost of financing inventory and other working capital, and increased the prices realized for product sales. Pursuant to the SOA, we estimate that Vitol held inventories of VGO and crude oil feedstock (both delivered and in-transit) valued at approximately $502.5 million at June 30, 2010 (as compared to $582.1 million at December 31, 2009), which would have otherwise been assets of Harvest.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our second quarter of 2010 relative to the preceding quarter:

	2010	
($000's)	**Q2**	Q1
Revenue, net of royalties	**$ 1,024,896**	$ 569,762
Net income (loss)	**18,203**	(39,240)
Cash from operating activities	**122,333**	78,134
Total long term debt	**1,177,945**	1,174,375
Total assets	**$ 4,758,472**	$ 4,765,580

Revenues are comprised of revenues net of royalties from our Upstream operations as well as sales of refined products from our Downstream operations. First quarter revenues were lower than second quarter revenues primarily due to the fire in the refinery that occurred in early January 2010 that resulted in the shutdown of production units for approximately eight weeks to conduct repairs. Second quarter Downstream revenues were $820.5 million compared to $339.8 million in the first quarter. Upstream revenues in the second quarter were $245.6 million compared to $271.7 million in the first quarter predominantly due to lower commodity prices for oil and natural gas.

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 goodwill impairment impact net income from period to period. For these reasons, our net income (loss) may not necessarily reflect the same trends as net revenues or cash from operating activities, nor is it expected to. Net Income of $18.2 million in the second quarter compared to a net loss of $39.2 million in the first quarter is related to the increase in revenue contributed from our Downstream operations for the reasons as discussed above.

Changes in cash from operating activities are 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. During the second quarter cash from Upstream operating activities was lower due to lower commodity prices and the higher operating costs due to the increased cost of electricity. Downstream cash flow from operations increased in the second quarter as the production units resumed operations following the completion of repairs for the January fire. The first quarter of 2010 was impacted by reductions in refinery throughput resulting from the unplanned downtime as a consequence of the fire in January 2010, partially offset by an increase in realized prices in the Upstream segment.

Total debt and total assets over the two reported quarters have remained relatively stable. The stability in total assets reflects minimal acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges.

OUTLOOK

The evolution of Harvest to a growth oriented, integrated, oil and gas company continued in the second quarter. Harvest has assembled an enviable asset base with growth opportunity that it is looking to complement with additional assets in the years ahead. A strong balance sheet, solid and increasing technical capability, and support for growth from KNOC will position Harvest well.

Subsequent to June 30, 2010, we successfully closed on the acquisition of the BlackGold oil sands project from KNOC for approximately $374 million of equity. We also signed a purchase and sale agreement to purchase certain petroleum and natural gas assets for $150 million. Further details of these subsequent events are discussed in Note 18 of the June 30, 2010 interim financial statements. With the inclusion of these subsequent event acquisitions, we anticipate that our upstream production will average approximately 36,300 bbls/d of liquids and 81,000 mcf/d of natural gas with operating costs approximately $14.00/boe. Upstream capital spending plans for 2010 are increased to $415 million which includes anticipated spending for the BlackGold project which will be financed through capital injections from KNOC. We will continue to evaluate opportunities to acquire producing oil and/or natural gas properties as well as offer selected properties for divestment to increase or maintain our productive capabilities.

In our downstream business, we currently anticipate spending approximately $120 million on capital projects, including $80 million for the discretionary Debottleneck Projects. The Debottleneck Projects are a suite of investments planned for the next couple years that will increase throughput, improve reliability, enhance margins and reduce operating costs. The shutdown of the platformer, hydrocracking, distillate hydrotreating units previously planned for 2010 have been deferred to 2011, so there will be no turnaround or catalyst expenditures in 2010. Full year throughput is projected to average 90,000 bpd of feedstock with a refined product yield of 45% distillates, 30% gasoline and 25% HSFO. We also project that operating costs and purchased energy costs will aggregate to $6.25 per bbl.

Currently the economic environment is mixed for Harvest with strong crude oil and natural gas liquids prices and improving refining margins offset by weaker natural gas prices. We anticipate that we will continue to see a volatile commodity price environment in 2010. With an oil-weighted upstream business and assuming that crude oil prices remain strong, Harvest should reflect strong cash flow in 2010 relative to 2009.

While we do not forecast commodity prices nor refining margins, we may enter into commodity price risk management contracts from time-to-time to mitigate some portion of our price volatility with the objective of stabilizing our cash flow from operating activities. The following table reflects the sensitivity of our 2010 cash flow from operating activities over the remaining six months of the year to changes in the following benchmark prices:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 80.00	$ 5.00	$ 23 mm
CAD/USD exchange rate	$ 0.95	$ 0.05	$ 26 mm
AECO daily natural gas price	$ 4.00	$ 1.00	$ 13 mm
Refinery crack spread (US$/bbl)	$ 9.00	$ 1.00	$ 21 mm
Upstream operating expenses (per boe)	$ 14.00	$ 1.00	$ 10 mm

Overall, we expect that based on current commodity price expectations, our 2010 cash from operating activities will be sufficient to fund our planned capital expenditures and continue to reduce bank debt.

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 are settled and when these activities are recognized for accounting purposes. 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.

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 the six months ended June 30, 2010.

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 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 and early adoption allowed. 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. Harvest is currently assessing the impact of this standard on our financial position and future results.

International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board (“AcSB”) announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards (“IFRS”) commencing January 1, 2011, including comparatives for 2010 and an opening balance sheet at January 1, 2010 showing the changes from Canadian GAAP to IFRS.

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 to ensure we meet the IFRS transition requirements for 2011. The IFRS project team has developed an IFRS Transition Plan that consists of four key phases:

IFRS Conversion Project Phase

Phase 1 – Diagnostic Phase

- Assessment of key differences between Canadian GAAP and IFRS, planning, assessment, implementation and training.

Phase 2 – Planning Phase

- Development of a project plan that includes assignment of roles and responsibilities, timeline and budget.

Phase 3 – Assessment Phase

- Detailed comparison of the IFRS and Canadian standards to identify all applicable differences, IFRS 1 First Time Adoption to IFRS exemptions and exemptions and expected changes to the relative IFRS standards.
- Impact assessment on accounting policies; information technology and data systems; business processes and data requirements; internal control over financial reporting, disclosure controls and procedures; financial reporting expertise and business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements.

Phase 4 – Implementation Phase

- Preparing transitional opening IFRS financial statements; implementing accounting policy changes; implementing and test data, process, system and control changes; training

IFRS Project Status

The diagnostic and planning phases of the project have been completed and Harvest has completed the detailed analysis of the differences for most elements of our financial statements and is currently working with representatives from various operational areas in the Company to finalize the selection of accounting policies and assess the impact of the differences on the data requirements, business processes, financial systems and internal controls. Harvest has commenced training of key employees through this process as well. Korea is on the same IFRS conversion schedule as Canada and as a result the IFRS accounting policies that were initially selected were reassessed to ensure that they align with KNOC's accounting policy choices.

Management is in the process of finalizing its chosen IFRS accounting policies and as such is unable to quantify the impact of adopting IFRS on its financial statements at this time.

Potential Impacts of IFRS Adoption

Significant differences that have been identified between Canadian GAAP and IFRS that will impact Harvest are: accounting for capital assets including exploration costs, depletion and depreciation, impairment testing, asset retirement obligations, employee benefits as well as an increased level of disclosure requirements. These differences have been identified based on the current IFRS standards issued and expected to be in effect on the date of transition. Current IFRS standards may be modified, and as a result, the impact may be different than Harvest's current expectations; as such, Harvest cannot guarantee that the following information will not change as the date of transition approaches. Harvest will continue to communicate information in relation to its conversion process as it becomes available.

First Time Adoption of IFRS

IFRS 1, "First Time Adoption of International Financial Reporting Standards" ("IFRS 1") prescribes requirements for preparing IFRS-compliant financial statements in the first reporting period after the changeover date. IFRS 1 requires retrospective application of IFRS as if they were always in effect. IFRS 1 also provides entities adopting IFRS for the first time with a number of mandatory exceptions and optional exemptions from retrospective application of IFRS to ease the transition to IFRS in the transition year. Management is assessing the exemptions available under IFRS 1 and will implement those determined to be most appropriate for Harvest. At present, Harvest believes it will apply the IFRS 1 exemptions associated with business combinations and arrangements containing a lease.

Property, Plant and Equipment ("PP&E")

IFRS requires costs recognized as PP&E to be allocated to the significant parts of the asset and to depreciate each significant component separately which is different from Harvest's current depreciation and depletion calculations under Canadian GAAP. The adoption of IFRS will increase the number of components to be amortized separately for both the upstream and downstream segments which could impact the amount of amortization expense recognized.

Exploration and Evaluation Expenditures ("E&E")

Oil and gas companies are required to account for exploration and evaluation expenditures in accordance with IFRS 6 "Exploration for and Evaluation of Mineral Resources". This standard addresses the recognition, measurement, presentation and disclosure requirements for costs incurred in the exploration phase. IFRS requires the identification and presentation of exploration and evaluation ("E&E") expenditures to be separated from those expenditures incurred on developed and producing properties. E&E expenditures are transferred to PP&E when technical feasibility and commercial viability has been proved. An impairment test is required to be performed on E&E expenditures when they are transferred to PP&E. Harvest will re-classify all E&E expenditures that are currently included in the PP&E balance and will consist of the book value of E&E land costs, and related drilling costs and seismic costs. E&E assets will not be depleted and will be assessed for impairment when indicators suggest the possibility of impairment.

Impairment of Assets

Under IFRS, impairment of PP&E will be calculated at a more granular level than what is currently required under Canadian GAAP as impairment will be calculated at the cash generating unit level. In addition, IAS 36 "Impairment of Assets" uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of value in use and fair value less costs to sell. Under IAS 36 impairment losses previously recognized may be reversed where circumstances change.

Asset Retirement Obligation ("ARO")

Under IFRS, the decommissioning liability is required to be remeasured at each reporting date using the current liability specific discount rate requiring retroactive adjustment to the estimated liability, whereas under Canadian GAAP, ARO adjustments are made on a prospective basis.

Employee Benefits

Under IFRS and Canadian GAAP, acturial gains and losses arising from defined benefit plans can be recognized into earnings through various appropriate methods, however, Canadain GAAP does not permit acturial gains and losses to be recognized directly in equity whereas IAS 19 "Employee Benefits" provides an additional accounting policy option to recognize acturial gains and losses directly in other comprehensive income in the period in which they occur.

Deferred Income Taxes

Due to the recent withdrawal of the exposure draft on IAS 12 "Income Taxes" in November 2009, Harvest is currently evaluating the differences between the current version of IAS 12 and the relevant Canadian GAAP standards.

Internal controls over financial reporting ("ICFR") and disclosure

As the IFRS accounting policies are finalized, an assessment will be made to determine changes required for ICFR. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements. Harvest has established internal controls associated with the IFRS transition which include approvals at various stages of the project and the involvement of its auditors and other external advisors.

Throughout the transition process, Harvest will be assessing stakeholders' information requirements and will ensure that adequate and timely information is provided so all stakeholders are informed of the transition progress.

IT systems

The conversion to IFRS will have an impact on the company's IT system requirements. Harvest is currently completing its IT systems impact assessment and it is expected that modifications will include the requirement to track PP&E costs and E&E costs separately as well as the tracking of costs at a more granular level of detail for IFRS reporting. It is expected that current accounting systems and processes will accommodate the modifications required for IFRS reporting.

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. Harvest has a risk management committee that meets on a regular basis to assess and manage operational and business risks. We intend to continue executing our business plan to create value.

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.
- 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 severe 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.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs.
- Our crude oil sales and refining margins are denominated in US dollars while we incur costs in Canadian dollars which results in a currency exchange exposure.
- Changes in tax and other laws my affect shareholders. Income tax laws, other laws or government incentive programs relating to the oil and gas industry, may in the future be changed or interpreted in a manner that affects Harvest or its stakeholders.
- Although the Corporation monitors the credit worthiness of third parties it contracts with through a formal risk management policy, there can be no assurance that the Corporation will not experience a loss for non-performance by any counterparty with whom it has a commercial relationship. Such events may result in material adverse consequences on the business of the Corporation.

CHANGES IN REGULATORY ENVIRONMENT

Alberta

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 the 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.

On March 3, 2009, the Government of Alberta announced a new three-point stimulus plan, and extended the plan to two years on June 25, 2009. The drilling royalty credit for new conventional oil and natural gas wells is a two-year program effective for wells spud on or after April 1, 2009, and will provide a $200 per-metre-drilled royalty credit, with the maximum credit determined on a sliding scale based on the individual company's total Alberta-based 2008 Crown oil and gas production. The royalty rate cap is also effective April 1, 2009 for new conventional oil and natural gas wells and will provide a maximum 5% royalty rate for the first 12 months of production, to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas per well, to all new wells that begin producing conventional oil or natural gas between April 1, 2009 and March 31, 2011. The third point is an abandonment and reclamation fund which will provide $30 million to be invested by the Orphan Well Association to abandon and reclaim old well sites where there is no legally responsible or financially able party available.

On May 27, 2010, in connection with its competitiveness review, the Province amended the maximum royalty rates and royalty curves applicable to the New Royalty Framework and amended the new well incentive program that applied to wells commencing production of conventional oil or natural gas on or after April 1, 2009 that was scheduled to expire on March 31, 2011 so that the program was permanent. The incentive provides for a maximum 5% royalty rate for the first 18 to 48 months of production, to a maximum of 50,000 to 100,000 barrels of oil equivalent depending on the depth of the well. The Province will review this program in 2014 and committed to provide three years notice prior to eliminating it.

Saskatchewan

Crown natural gas royalty rates are sensitive to the individual productivity of each well. The rates are applied to the respective portions of each classification of gas ("fourth tier gas", "third tier gas", "new gas" and "old gas") produced from a well.

Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price ("PGP") established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in $/103m3) received by producers during the month for the sale of all gas subject to royalty. Crown royalty of the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis. The operator must elect to use either the PGP or the Operator Average Gas Price ("OGP") for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($/103m3) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month.

Crown royalty rates for conventional oil are sensitive to the individual productivity of each well and the type of oil produced from the well. Each month, royalty rates are adjusted based on the level of the reference price established by the Province for each type of oil. For Crown royalty purposes, crude oil is classified as "heavy oil", "southwest designed oil" or "non-heavy oil other than southwest designated oil". There are separate reference prices established for each type of oil which represent the average wellhead price (in $/m3) received by producers during the month for sales of that oil type in Saskatchewan.

The Crown royalty share of production volume is calculated on each individual well using the applicable royalty rate to the volume of oil produced from the well each month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month. A separate cost sensitive royalty structure applies to incremental production from enhanced oil recovery projects, which incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

Saskatchewan has introduced a new orphan oil and gas well and facility program, solely funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

British Columbia

The British Columbia natural gas royalty regime is price-sensitive, using a "select price" as a parameter in the royalty rate formula. When the reference price, being the greater of the producer price or the Crown set posted minimum price ("PMP"), is below the select price, the royalty rate is fixed. The rate increases as prices increase above the select price. The Government of British Columbia determines the producer prices by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. If this price is below the PMP, the PMP will be the price of the gas for royalty purposes.

Natural gas is classified as either "conservation gas" or "non-conservation gas". There are three royalty categories applicable to non-conservation gas, which are dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas. However, the royalty rate may be reduced for low productivity wells.

The royalty regime for oil is dependent on age and production. Oil is classified as "old", "new" or "third tier" and a separate formula is used to determine the royalty rate depending on the classification. The rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil to reflect the increased cost of exploration and extraction. There is no minimum royalty rate for oil.

In May 2008, the Government of British Columbia introduced the Net Profit Royalty Program to stimulate development of high risk and high cost natural gas and oil resources in British Columbia that are not economic under other royalty programs. The program allows for the calculation of royalties based on the net profits of a particular project and is governed under the Net Profit Royalty Regulation, which came into effect in May 2008.

On August 6, 2009, the Province of British Columbia announced an Oil and Gas Stimulus package providing for:

- A one-year, two per cent royalty rate for all natural gas wells drilled in a 10 month window (September 2009 - June 2010).
- An increase of 15 per cent in the existing royalty deductions for natural gas deep drilling.
- Qualification of horizontal wells drilled between 1,900 and 2,300 metres into the Deep Royalty Credit Program.

An additional $50 million was allocated in the fall of 2009 for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

Environmental Regulation

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

As part of the corporate reorganization and dissolution of the Trust on May 1, 2010, the newly reorganized company, Harvest Operations Corp. will continue to assume the disclosure controls and procedures of the Trust. Under the supervision of the Chief Executive Officer and Chief Financial Officer, the Trust had evaluated the effectiveness of its disclosure controls and procedures as of December 31, 2009 as defined under the rules adopted by the Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer had concluded that as of December 31, 2009, the disclosure controls and procedures were effective to ensure that information required to be disclosed by the Trust 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 management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

During the six months ended June 30, 2010, there were no changes in our disclosure controls and procedures that have materially affected, or are reasonably likely to materially affect, our disclosure controls and procedures.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining internal control over the Company’s financial reporting. As part of the corporate reorganization and dissolution of the Trust on May 1, 2010, the newly reorganized company, Harvest Operations Corp. will continue to assume the internal controls and processes of the Trust. The Company’s internal controls are 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 of the Trust, with the participation of its Chief Executive Officer and Chief Financial Officer, had evaluated the effectiveness of its internal control over financial reporting as of December 31, 2009. 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 had concluded that as of December 31, 2009, the design and operation of internal controls were effective.

During the six months ended June 30, 2010, 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, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(thousands of Canadian dollars)	**June 30, 2010**	December 31, 2009
Assets		
Current assets		
Cash	$ **5,162**	$ -
Accounts receivable and other	**194,928**	180,839
Prepaid expenses and deposits	**13,004**	15,551
Inventories *[Note 4]*	**69,341**	86,819
Fair value of risk management contract *[Note 15]*	**257**	-
	282,692	283,209
Property, plant and equipment *[Note 5]*	**4,070,837**	4,090,653
Goodwill *[Note 1]*	**404,943**	404,943
	$ **4,758,472**	$ 4,778,805
Liabilities and Shareholder's Equity		
Current liabilities		
Bank loan *[Note 8]*	$ **-**	$ 428,017
Accounts payable and accrued liabilities *[Note 6]*	**196,715**	216,563
Current portion of convertible debentures *[Note 10]*	**23,974**	182,806
Current portion of $7^{7/8}$% senior notes *[Note 9]*	**-**	42,921
Fair value deficiency of risk management contracts *[Note 15]*	**-**	2,052
	220,689	872,359
Bank loan *[Note 8]*	**182,421**	-
$7^{7/8}$% senior notes *[Note 9]*	**224,744**	222,456
Convertible debentures *[Note 10]*	**746,806**	748,261
Asset retirement obligation *[Note 7& 6]*	**287,440**	284,042
Employee future benefits *[Note 14]*	**17,583**	17,453
Deferred credit	**363**	358
Future income tax *[Note 13]*	**191,139**	211,188
	1,871,185	2,356,117
Shareholder's equity		
Shareholder's capital *[Note 11]*	**2,888,367**	2,422,688
Retained earnings (deficit)	**(21,036)**	-
Accumulated other comprehensive income	**19,956**	-
	2,887,287	2,422,688
	$ **4,758,472**	$ 4,778,805

Commitments and contingencies *[Note 17]*
Subsequent events *[Note 18]*
See accompanying notes to these consolidated financial statements.

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

(thousands of Canadian dollars)	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Revenue		
Petroleum, natural gas, and refined product sales	$ 1,066,096	$ 1,677,614
Royalty expense	(41,200)	(82,956)
	1,024,896	1,594,658
Expenses		
Purchased products for processing and resale	731,778	1,062,351
Operating	125,646	235,088
Transportation and marketing	4,432	7,590
General and administrative	12,167	25,025
Realized gains on risk management contract *[Note 15]*	(1,200)	(187)
Unrealized gains on risk management contract *[Note 15]*	(2,200)	(2,309)
Interest and other financing charges on short term debt, net	312	1,493
Interest and other financing charges on long term debt	17,978	36,064
Depletion, depreciation, amortization and accretion	130,558	262,227
Currency exchange loss	2,548	8,619
Large corporations tax (recovery) and other taxes	(242)	(218)
Future income tax (reduction)	(15,084)	(20,049)
	1,006,693	1,615,694
Net income (loss) for the period	18,203	(21,036)
Other comprehensive income		
Cumulative translation adjustment	46,902	19,956
Comprehensive loss for the period	$ 65,105	$ (1,080)

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGE IN SHAREHOLDER'S EQUITY (UNAUDITED)

As at June 30, 2010*(thousands of Canadian dollars)*

	Shareholder's Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income
At December 31, 2009	**$ 2,422,688**	**$ -**	**$ -**
Issued for cash			
January 29, 2010	465,679	-	-
Currency translation adjustment	-	-	19,956
Net loss	-	(21,036)	-
At June 30, 2010	**$ 2,888,367**	**$ (21,036)**	**$ 19,956**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Cash provided by (used in)		
Operating Activities		
Net loss for the period	$ 18,203	$ (21,036)
Items not requiring cash		
Depletion, depreciation, amortization and accretion	130,558	262,227
Unrealized currency exchange (gain) loss	(3,026)	3,425
Non-cash interest expense and amortization of finance charges	(919)	(4,733)
Unrealized gains on risk management contracts	(2,200)	(2,309)
Future income tax (reduction)	(15,084)	(20,049)
Employee benefit obligation	78	130
Other non-cash items	104	(9)
Settlement of asset retirement obligations *[Note 7]*	(2,367)	(8,017)
Change in non-cash working capital	(3,012)	(9,160)
	122,335	200,469
Financing Activities		
Issue of common shares, net of issue costs	-	465,679
Bank repayments, net	(5,557)	(245,717)
Redemptions of senior notes	-	(42,262)
Redemptions of convertible debentures	-	(156,363)
Change in non-cash working capital	(3,454)	(2,841)
	(9,011)	18,496
Investing Activities		
Additions to property, plant and equipment	(60,773)	(182,985)
Property dispositions (acquisitions), net	726	(30,236)
Change in non-cash working capital	(52,610)	(5,306)
	(112,657)	(218,527)
Change in cash and cash equivalents	$ 667	$ 438
Effect of exchange rate changes on cash	4,495	4,724
Cash and cash equivalents, beginning of period	-	-
Cash and cash equivalents, end of period	$ 5,162	$ 5,162
Interest paid	$ 14,991	$ 28,714
Large corporation tax and other tax (received) paid, net	$ (242)	$ (218)

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Period ended June 30, 2010
(tabular amounts in thousands of Canadian dollars)

1. Nature of Operations and Structure of the Company

(a) Nature of Operations

Harvest Operations Corp. is an integrated energy company with petroleum and natural gas operations focused on the operation and further development of assets in western Canada ("upstream operations") and 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").

(b) Structure of the Company

On December 22, 2009, KNOC Canada Ltd. ("KNOC Canada"), a wholly owned subsidiary of Korea National Oil Corporation ("KNOC"), purchased all of the issued and outstanding trust units of Harvest Energy Trust (the "Trust) for $10.00 per unit and applied December 31, 2009 as the deemed acquisition date. The acquisition of all the issued and outstanding trust units of the Trust resulted in a change of control in which KNOC Canada became the sole equity owner of the Trust.

The aggregate consideration for the acquisition of the Trust consists of the following:

Consideration for the acquisition:	Amount
Cash paid to Trust unitholders	$ 1,822,688
Repayment of debt	600,000
	$ 2,422,688

This acquisition was accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at fair value with the excess of the consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the consideration to the fair value of the Trust's assets and liabilities:

	Amount
Property, plant and equipment	$ 4,090,653
Inventories	86,819
Goodwill	404,943
Net working capital (deficiency)	(20,531)
Total debt	(1,624,461)
Asset retirement obligations	(284,042)
Future income tax liability	(211,188)
Funding deficiency of pension and other benefit plans	(17,453)
Fair value of risk management contract	(2,052)
	$ 2,422,688

On May 1, 2010, an internal reorganization was completed pursuant to which the Trust was dissolved and the Trust's wholly owned subsidiary and manager of the Trust, Harvest Operations Corp., was amalgamated with KNOC Canada to continue as one corporation under the name Harvest Operations Corp ("Harvest" or the "Company"). The recorded amounts of Harvest's assets and liabilities were determined from the existing carrying values of KNOC Canada's assets and liabilities.

KNOC Canada was incorporated on October 9, 2009 and did not have any results from operations or cash flows in the period from October 9, 2009 to the deemed acquisition date of December 31, 2009 aside from capital injections from Korea National Oil Corporation to finance the purchase of the Trust. As KNOC Canada acquired the Trust on the deemed acquisition date of December 31, 2009, there is no comparative consolidated statement of income (loss) and comprehensive income (loss), statement of changes in shareholder's equity, or statement of cash flows for the period ended June 30, 2009.

The following unaudited pro forma consolidated results of operations have been prepared as if the acquisition of the Trust and the subsequent reorganization occurred on January 1, 2009:

	Three Months Ended June 30, 2009			
(thousands of Canadian dollars)	Harvest Energy Trust	Pro Forma Adjustments	Notes	Pro Forma Harvest Operations Corp.
Revenue				
Petroleum, natural gas, and refined product sales	$ 591,196			$ 591,196
Royalty expense	(28,199)			(28,199)
	562,997			562,997
Expenses				
Purchased products for processing and resale	322,855	-		322,855
Operating	142,737	(43,286)	(g)	99,451
Transportation and marketing	6,706	-		6,706
General and administrative	9,394	-		9,394
Realized gains on risk management contract	(19,430)	-		(19,430)
Unrealized net losses on risk management contract	14,999	-		14,999
Interest and other financing charges on short term debt, net	2,475	(2,475)	(b)(c)	-
Interest and other financing charges on long term debt	26,984	(8,220)	(b)(c)	18,764
Depletion, depreciation, amortization and accretion	136,695	5,980	(a)	142,675
Goodwill impairment	206,465	(206,465)	(e)	-
Currency exchange gains	(8,990)	-		(8,990)
Large corporations tax (recovery) and other taxes	(35)	-		(35)
Future income tax (reduction)	(12,079)	8,482	(g)	(3,597)
	828,776	(245,984)		582,792
Net loss for the period	(265,779)			(19,795)
Other comprehensive income				
Cumulative translation adjustment	(120,922)	14,363	(h)	(106,559)
Comprehensive loss for the period	$ (386,701)			$ (126,354)

	Six Months Ended June 30, 2009			
(thousands of Canadian dollars)	Harvest Energy Trust	Pro Forma Adjustments	Notes	Pro Forma Harvest Operations Corp.
Revenue				
Petroleum, natural gas, and refined product sales	$ 1,346,820			$ 1,346,820
Royalty expense	(52,728)			(52,728)
	1,294,092			1,294,092
Expenses				
Purchased products for processing and resale	704,692	-		704,692
Operating	262,847	(47,488)	(f)	215,359
Transportation and marketing	12,617	-		12,617
General and administrative	17,143			17,143
KNOC acquisition costs	-	18,393	(d)	18,393
Realized gains on risk management contract	(44,972)	-		(44,972)
Unrealized net losses on risk management contract	25,190	-		25,190
Interest and other financing charges on short term debt, net	2,535	(2,535)	(b)(c)	-
Interest and other financing charges on long term debt	59,576	(19,108)	(b)(c)	40,468
Depletion, depreciation, amortization and accretion	275,891	11,748	(a)	287,639
Goodwill impairment	206,465	(206,465)	(e)	-
Currency exchange gains	(8,892)	-		(8,892)
Large corporations tax (recovery) and other tax	(16)	-		(16)
Future income tax (reduction)	(10,069)	22,222	(g)	12,153
	1,503,007	(223,233)		1,279,774
Net income (loss) for the period	(208,915)			14,318
Other comprehensive income				
Cumulative translation adjustment	(71,104)	1,217	(h)	(69,887)
Comprehensive loss for the period	$ (280,019)			$ (55,569)

The following are summaries of the significant pro forma adjustments:

a) Additional depletion, depreciation, amortization and accretion based on the fair value adjustments to property, plant, and equipment.
b) Adjustment of the interest and other financing charges to reflect the estimated carrying cost of the debt assumed on acquisition.
c) The terms of the credit facility were amended on December 22, 2009 and again on April 30, 2010. Pro forma adjustments were made to adjust interest expense to apply the revised terms from the beginning of January 1, 2009.
d) Adjustment to reflect acquisition related costs that were incurred in the fourth quarter 2009 as if they occurred in the first quarter 2009.
e) Reversal of goodwill impairment expense recorded by the Trust.
f) Operating expense was adjusted to reflect KNOC Canada’s capitalization policy on turnaround and catalyst costs.
g) Taxes have also been adjusted for the effect of the items discussed.
h) Cumulative translation adjustment has been adjusted for the effect of the items discussed.

2. Significant Accounting Policies

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (“Canadian GAAP”).

(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, income taxes and amounts used in the impairment tests for 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 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. Major capital maintenance projects are capitalized but general 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.

Present value of 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 evaluation.

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 – 35 years
Structures	15 – 20 years
Catalysts	2 – 8 years
Tugs	25 years
Vehicles	2 – 7 years
Office and computer equipment	3 – 5 years

General maintenance and repair costs, including major maintenance activities, are expensed as incurred. Major replacements and capital maintenance projects such as turnaround costs are capitalized. 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.

(g) Capitalized interest

Interest on major development projects are capitalized until the project is complete using the weighted-average interest rate on all of Harvest's borrowings. Capitalized interest cannot exceed the actual interest incurred.

(h) Goodwill

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.

(i) 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.

(j) Income Taxes

Harvest follows the asset and 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 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.

(k) Employee Future Benefits

Harvest's Downstream operations maintains a defined benefit plan and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses.

(i) Defined Contribution Plan

Under the defined contribution plan, Harvest's annual contribution of each participating employee's pensionable earnings is as follows:

Employee category	**June 30, 2010**	December 31, 2009
Permanent	**5.0%**	5.0%
Part-time	**2.5%**	2.5%

The cost associated with the defined contribution plan is expensed as incurred.

(ii) Defined Benefit Plans

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 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.

(l) 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.

(m) Financial Instruments

Harvest classifies cash and price risk management contracts as held-for-trading and measures these instruments at fair value each reporting period. The remainders of Harvest's financial instruments are measured at amortized cost.

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.

3. New Accounting Policies

Future Accounting Changes

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA Handbook Section 1582 ''Business Combinations'' is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 ''Consolidated Financial Statements'' and 1602 ''Non-Controlling Interests''. These standards will require non-controlling interests to be presented as part of Shareholder's Equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted; Harvest has not elected to early adopt these standards. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("ASB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end. Harvest will begin reporting under IFRS as of January 1, 2011, but given the current stage of the Company's IFRS project the full impact of adopting IFRS on Harvest's financial position and future results can not be determined.

4. Inventories

		June 30, 2010		December 31, 2009
Petroleum products				
Upstream – pipeline fill	$	**1,590**	$	1,183
Downstream		**63,138**		81,240
		64,728		82,423
Parts and supplies		**4,613**		4,396
Total inventories	$	**69,341**	$	86,819

For the three and six month periods ended June 30, 2010, Harvest recognized inventory impairments of $2.2 million and $3.3 million, respectively in its downstream operations. Such write-down and recoveries amounts are included as costs in "Purchased products for processing and resale" in the consolidated statements of income (loss).

5. Property, Plant and Equipment

	June 30, 2010			December 31, 2009		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 3,187,974**	**$ 1,145,792**	**$ 4,333,766**	$ 2,976,911	$ 1,113,742	$ 4,090,653
Accumulated depletion and depreciation	**(221,163)**	**(41,766)**	**(262,929)**	-	-	-
Net book value	**$ 2,966,811**	**$ 1,104,026**	**$ 4,070,837**	$ 2,976,911	$ 1,113,742	$ 4,090,653

General and administrative costs of $2.8 million and $5.0 million have been capitalized during the three and six month periods ended June 30, 2010.

All costs, except those associated with major spare parts inventory and assets under construction, are subject to depletion and depreciation at June 30, 2010 including future development costs of $394 million. Downstream major parts inventory of $6.7 million and Downstream assets under construction of $42.5 million were excluded from the asset base subject to depreciation at June 30, 2010.

6. Accounts Payable and Accrued Liabilities

		June 30, 2010		December 31, 2009
Trade accounts payable	$	**58,727**	$	71,309
Accrued interest		**13,688**		16,530
Other accrued liabilities		**109,106**		117,538
Current portion of asset retirement obligation		**15,194**		11,186
Total	$	**196,715**	$	216,563

7. 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 $1,211 million which will be incurred between 2010 and 2060. 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:

		June 30, 2010		December 31, 2009
Balance, beginning of year	$	**295,228**	$	277,318
Incurred on business acquisition of a private corporation		**-**		1,411
Liabilities incurred		**830**		1,351
Revision of estimates		**-**		7,219
Net liabilities acquired (settled) through acquisition (disposition)		**2,077**		(2,538)
Liabilities settled		**(8,017)**		(14,270)
Accretion expense		**12,516**		24,737
Balance, end of year[(1)]	$	**302,634**	$	295,228

(1) Current portion of the asset retirement obligation is included in accounts payable and accrued liabilities [Note 6]

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.

8. Bank Loan

At the time of the purchase of the Trust by KNOC Canada on December 22, 2009, the Trust had renegotiated a temporary credit facility of $600 million with the maturity date of April 30, 2010. On April 30, 2010, Harvest entered into an amended and extended credit facility maturing April 30, 2013 and the facility was reduced from $600 million to $500 million. Harvest continues to pay a floating interest rate, which is determined by a grid based on the Company's secured debt (excluding 7 7/8% senior notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash items ("EBITDA"). The minimum rate charged in the grid is 200 bps over bankers' acceptance rates as long as Harvest's secured debt to EBITDA ratio remains below or equal to one. At June 30, 2010, Harvest had $182.4 million drawn from the $500 million available under the credit facility ($428.0 million drawn from the $600 million available at December 31, 2009).

The credit facility is secured by first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the downstream operation's refinery assets. 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 shareholders 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 EBITDA. In addition to the availability under this facility being limited by the Borrowing Base Covenant of the 7⅞% senior notes described in Note 9, availability is subject to the following quarterly financial covenants:

	Covenant	As at June 30, 2010
Secured debt to EBITDA	3.0 to 1.0 or less	0.36
Total debt to EBITDA	3.5 to 1.0 or less	2.28
Secured debt to Capitalization	50% or less	5%
Total debt to Capitalization	55% or less	29%

For the three and six month ended June 30, 2010, interest charges on bank loans aggregated to $1.1 million and $1.7 million, reflecting an effective interest rate of 1.95% and 1.51%.

9. 7⅞% senior notes

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of the former Trust, 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, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

The 7⅞% senior notes indenture contains a change of control provision that required Harvest Operations Corp. to commence an offer to repurchase 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. On December 22, 2009, concurrent with the acquisition of 100% of the Trust by KNOC Canada, the change of control provision was triggered and on January 20, 2010 Harvest Operations Corp. made an offer, which expired on February 16, 2010, to purchase 100 7⅞% senior notes for cash consideration of 101% of the principal amount thereof plus the accrued and unpaid. As a result of the offering, US$40.4 million principal amount was redeemed.

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 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, 2009, the borrowing base covenant restricts secured indebtedness to Cdn$1.87 billion.

In addition, the covenants of the senior notes restrict the amount of dividends Harvest can pay to shareholders; no dividends have been paid during the sixth month period ended June 30, 2010.

10. Convertible debentures

Harvest has five 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.

As a result of the Trust's acquisition, the debentures are no longer convertible into units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. Because every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option.

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.

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

Series	Conversion price / share	Maturity	First redemption period	Second redemption period
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:

	June 30, 2010			December 31, 2009		
	Face Value	**Carrying Amount**	**Fair Value**	Face Value	Carrying Amount	Fair Value
6.5% Debentures Due 2010	**23,810**	**23,974**	**24,120**	37,062	37,562	37,562
6.40% Debentures Due 2012	**106,796**	**107,734**	**108,013**	174,626	176,460	176,460
7.25% Debentures Due 2013	**330,548**	**335,503**	**333,853**	379,256	385,703	385,703
7.25% Debentures Due 2014	**60,050**	**60,964**	**60,951**	73,222	74,467	74,467
7.5% Debentures Due 2015	**236,599**	**242,605**	**240,739**	250,000	256,875	256,875
	$ 757,803	**$770,780**	**$767,676**	$914,166	$931,067	$931,067

The "change of control" provision included within the convertible debentures' indentures required Harvest to make an offer to purchase 100% of the outstanding convertible debentures for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest. Harvest made these offers on January 20, 2010 and by March 4th all of the offers had expired. The following redemptions were made:

- 6.5% Debentures due 2010 – $13.3 million principal amount tendered leaving a principal balance of $23.8 million outstanding
- 6.4% Debenture due 2012 – $67.8 million principal amount tendered leaving a principal balance of $106.8 million outstanding
- 7.25% Debentures due 2013 – $48.7 million principal amount tendered leaving a principal balance of $330.5 million outstanding
- 7.25% Debentures due 2014 – $13.2 million principal amount tendered leaving a principal balance of $60.1 million outstanding
- 7.5% Debentures due 2015 – $13.4 million principal amount tendered leaving a principal balance of $236.6 million outstanding

11. Shareholder's Capital

(a) Authorized

The authorized capital consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series.

(b) Number of Common Shares Issued

Outstanding at October 8, 2009	-
Common shares issued to KNOC at $10.00 per share to fund Trust acquisition	242,268,801
Outstanding at December 31, 2009	242,268,801
Common shares issued to KNOC at $10.00 per share to fund debt repayment	46,567,852
Outstanding at June 30, 2010	288,836,653

12. Capital Structure

Harvest considers its capital structure to be its credit facilities, senior notes, convertible debentures and shareholder's equity.

		June 30, 2010		December 31, 2009
Bank debt	$	**182,421**	$	428,017
$7^{7/8}$% senior notes (US$209.6 million) (1)		**223,104**		262,750
Principal amount of convertible debentures		**757,803**		914,166
Total Debt		**1,163,328**		1,604,933
Shareholder's equity		**2,887,287**		2,422,688
Total capitalization	$	**4,050,615**	$	4,027,621

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

Harvest's primary objective in its management of capital resources is to have access to capital to fund its financial obligations as well as future growth. Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting these objectives. Accordingly, Harvest may adjust its capital spending programs, issue equity, issue new debt or repay existing debt.

Harvest evaluates its capital structure using the following non-GAAP financial ratios: bank debt to twelve month trailing EBITDA; secured debt to net present value of the Company's proved petroleum and natural gas reverses discounted at 10%; and total debt to total debt plus shareholder's equity. These ratios are also included in the externally imposed capital requirements per the Company's credit facility, senior notes and convertible debentures; Harvest was in compliance with all debt covenants at June 30, 2010.

13. Income Taxes

The future income tax ("FIT") provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the legal entities of Harvest and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in FIT expense (recovery).

As KNOC Canada acquired the Trust on the deemed acquisition date of December 31, 2009, the opening FIT liability is calculated as part of the purchase price allocation recorded at that date. The opening FIT liability of $211.2 million represents a tax liability based on the excess book over tax value of net assets and the related tax impact is calculated at corporate tax rates applicable to the relevant province.

At the end of the six months ended June 30 2010, Harvest had a net FIT liability on the balance sheet of $191.1 million comprised of a $89.0 million FIT liability for the downstream corporate entities and $102.1 million FIT liability for the upstream entities.

FIT liability (asset)	
Opening FIT Liability, January 1, 2010 (from PPA)	211,188
Ending FIT Liability, June 30, 2010	191,139
	(20,049)
Consists of:	
FIT recovery for period ended June 30, 2010	(20,049)
Total	(20,049)

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:

		For the six months ended June 30, 2010
Income (loss) before taxes	$	**(41,303)**
Combined Canadian Federal and Provincial statutory income tax rate		**28.25%**
Computed income tax expense (recovery) at statutory rates		**(11,668)**
Increased expense (recovery) resulting from the following:		
Difference between current and expected tax rates		**(9,196)**
Non-taxable portion of capital (gain) loss		**57**
Non-deductible expenses		**758**
FIT expense (recovery)		**(20,049)**

The components of the FIT (asset)/liability are as follows:

	June 30, 2010	December 31, 2009
Net book value of petroleum and natural gas assets in excess of tax pools	**$ 523,021**	$ 560,169
Net book value of intangible assets	**(5,442)**	14,474
Asset retirement obligation	**(78,019)**	(75,784)
Net unrealized losses related to risk management contracts and currency exchange positions – current	**(815)**	(3,248)
Net unrealized losses related to risk management contracts and currency exchange positions – long-term	**5,432**	6,681
Non-capital loss carry forwards for tax purposes	**(250,590)**	(289,647)
Deferral of taxable income in partnership	**1,200**	681
Future employee retirement costs	**(3,656)**	(2,094)
Working capital and other items	**8**	(44)
FIT liability (asset), net	**$ 191,139**	$ 211,188

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

Year of Expiry	
2013	$ 9,768
2014	40,411
2023	366
2024	902
2025	97,444
2026	40,698
2027	457,336
2028	353,884
2029	107,605
Consolidated non-capital losses	$ 1,108,414

14. 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 are as follows:

	June 30, 2010		December 31, 2009	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Discount rate	**5.5%**	**5.5%**	5.5%	5.5%
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	**-**	**8%**	-	9%
Expected average remaining service lifetime (years)	**12.0**	**10.3**	12.2	10.5

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

	Percentage of Plan Assets	
Asset Category	**June 30, 2010**	**December 31, 2009**
Bonds/fixed income securities	**31%**	31%
Equity securities	**69%**	69%

Total cash payments for employee future benefits, consisting of cash contributed by Harvest to the pension plans and other benefit plans was $1.3 million for the period ended June 30, 2010.

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, 2009, and the next valuation report is due no later than December 31, 2010. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2009.

	June 30, 2010	
	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of period	$56,476	$7,047
Current service costs	1,094	146
Interest	1,633	198
Actuarial (gains)/losses	780	68
Benefits paid	(833)	(191)
Employee benefit obligation, end of period	59,150	7,268
Fair value of plan assets, beginning of period	46,070	-
Actual return (loss) on plan assets	1,648	-
Employer contributions	1,170	123
Employee contributions	780	68
Benefits paid	(833)	(191)
Fair value of plan assets, end of period	48,835	-
Funded status and carrying amount	$(10,315)	$(7,268)

	June 30, 2010	December 31, 2009
Summary:		
Pension plans	**$10,315**	$10,406
Other benefit plans	**7,268**	7,047
	$17,583	$17,453

Expected remaining contributions in 2010 are approximately $2.7 million for the pension plans and $0.1 million for the other benefit plan.

Estimated pension and other benefit payments to plan participants which reflect expected future service, expected to be paid from 2010 to 2019, are as follows:

	Pension Plans	**Other Benefit Plans**
2010	**$ 833**	**$ 191**
2011	**1,926**	**543**
2012	**2,145**	**655**
2013	**2,419**	**786**
2014	**2,887**	**943**
2015 to 2019	**21,663**	**7,303**
Total	**$ 31,873**	**$ 10,421**

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

	June 30, 2010			
	Three Months Ended		Six Months Ended	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Current service cost	$547	$73	$1,094	$146
Interest costs	816	99	1,633	198
Expected return on assets	(824)	-	(1,648)	-
Amortization of net actuarial gains	-	-	-	-
Net benefit plan expense	$539	$172	$1,079	$344

A 1% change in the expected health care cost trend rate would have the following annual impacts as at June 30, 2010:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 1	$ (2)
Impact on projected benefit obligation	16	(25)

15. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, deposits, accounts payable and accrued liabilities, bank loan, risk management contracts, convertible debentures and the 7⅞% senior notes. The carrying value and fair value of these financial instruments at June 30, 2010 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the year ended June 30, 2010:

	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	$ 194,928	$ 194,928	$ -	$ 55 [2]	$ -
Assets Held for Trading					
Net fair value of risk management contracts	257	257	(2,496) [3]	-	-
Other Liabilities					
Accounts payable[6]	181,532	181,532	-	-	-
Bank loan	182,421	185,604	-	(2,894)[4]	-
$7^{7/8}$% Senior Notes	224,744 [1]	224,777	-	(8,356) [5]	-
Convertible Debentures	$ 770,780	$ 767,676	$ -	$ (26,307) [5]	$ -

(1) The face value of the 7⅞% Senior Notes at June 30, 2010 is $223.1 million (U.S. $209.6 million).
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included realized and unrealized gains on risk management contracts 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 non-cash interest expense relating to the accretion of transaction costs that are netted against this liability is included in non-cash interest 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/income relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities is included in non-cash interest in the statement of cash flows.
(6) Excludes current portion of asset retirement obligation.

(a) Fair Values

The fair values of the convertible debentures and the 7⅞% senior notes are based on quoted market prices as at June 30, 2010. 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; the carrying value of bank loan includes $3.2 million of deferred financing charges at June 30, 2010. Due to the short term nature of accounts receivable, deposits, accounts payable, their carrying values approximate their fair values.

Harvest's financial assets and liabilities recorded at fair value have been classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Harvest's cash and risk management contracts have been assessed on the fair value hierarchy described above; cash is classified as Level 1 and risk management contracts as Level 2.

(b) Risk Management Contracts

At June 30, 2010, the fair value asset reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $0.3 million (December 31, 2009 – fair value deficiency of $2.1 million).

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at June 30, 2010:

Electricity Price Risk Management				
Quantity	Type of Contract	Term	Average Price	Fair value
25 MWh	Electricity price swap contracts	Jan. 10 – Dec. 10	Cdn $59.22	$ (8)
5 MWh	Electricity price swap contracts	Jan. 11 – Dec. 11	Cdn $45.85	$ 265
Total				$ 257

For the three and six months ended June 30, 2010, the total unrealized gain recognized in the consolidated statement of income and comprehensive income on the change in fair value of risk management contracts was $2.2 million and $2.3 million. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

(c) 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 the Company's debt.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in Harvest's 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 exposed to credit risk from the counterparties to its risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties limited to lenders in its syndicated credit facilities; Harvest has no history of losses with these counterparties.

Downstream Accounts Receivable

The supply and offtake agreement exposes 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. Pursuant to the agreement, Vitol is required to 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 June 30, 2010 accordingly the outstanding balance is included in current trade accounts payable in the liability liquidity table.

Harvest's maximum exposure to credit risk relating to the above classes of financial assets at June 30, 2010 is the carrying value of accounts receivable. The table below provides an analysis of Harvest's current financial assets and the age of its past due but not impaired financial assets by type of credit risk.

		Overdue AR			
	Current AR	≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream Accounts Receivable	$ 109,078	$ 1,150	$ 289	$ 230	$ 12,231[1]
Risk Management Contract Counterparties	-	-	-	-	-
Downstream Accounts Receivable	67,054	3,523	509	246	618
Total	$ 176,132	$ 4,673	$ 798	$ 476	$ 12,849

[1] Includes a $4.0 million allowance for doubtful accounts.

(ii.) Liquidity Risk

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

The following table provides an analysis of Harvest's financial liability maturities based on the remaining terms of its liabilities as at June 30, 2010 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	$ 167,844	$ -	$ -	$ -	$ 167,844
Settlement of risk management contract	(257)	-	-	-	(257)
Bank loan and interest	2,467	9,789	184,030	-	196,286
Convertible debentures and interest	51,257	211,435	448,992	243,891	955,575
7⅞% senior notes and interest	8,857	236,919	-	-	245,776
Pension contributions	2,800	8,448	8,789	4,527	24,564
Asset retirement obligations	16,186	28,189	26,335	1,140,499	1,211,209
Total	$ 249,154	$ 494,780	$ 668,146	$1,388,917	$2,800,997

(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.

Harvest has 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 six months of data, Harvest factors in the seasonality of the 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 the Company's 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.

At June 30, 2010, if interest rates had decreased by 200% with all other variables held constant, after-tax net income for the year would have been $0.3 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 200%, with all other variables held constant, the after-tax net income would have been $1.1 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.$209.6 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 its 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 June 30, 2010, 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	$ (17,741)
U.S. Dollar Exchange Rate - 8% decrease	$ 17,741

Harvest's downstream operations operates with a U.S. dollar functional currency which gives rise to currency exchange rate risk on the Company'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	$ (2,841)
Canadian Dollar Exchange Rate - 8% decrease	$ 2,841

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its 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 power price. Variances in expected future prices expose Harvest to commodity price risk as changes will result in a gain or loss that Harvest will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts. Harvest uses power hedge contracts as an effective method of reducing its cash power expense.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at June 30, 2010, net income would be impacted as follows:

	Impact on Net Income
Forward price of power - 57% increase	$ 5,500
Forward price of power - 48% decrease	$ (4,448)

16. 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.

	Three Month Ended June 30, 2010			Six Month Ended June 30, 2010		
	Downstream	Upstream	Total	Downstream	Upstream	Total
Revenue(2)	$ 820,530	$ 245,566	$1,066,096	$1,160,317	$ 517,297	$ 1,677,614
Royalties	-	(41,200)	(41,200)	-	(82,956)	(82,956)
Less:						
Purchased products for resale and processing	731,778	-	731,778	1,062,351	-	1,062,351
Operating	57,318	68,328	125,646	102,507	132,581	235,088
Transportation and marketing	2,364	2,068	4,432	3,315	4,275	7,590
General and administrative	441	11,726	12,167	882	24,143	25,025
Depletion, depreciation, amortization and accretion	20,179	110,379	130,558	40,624	221,603	262,227
	$ 8,450	$ 11,865	$ 20,315	$ (49,362)	$ 51,739	$ 2,377
Realized gains on risk management contracts			1,200			187
Unrealized net losses on risk management contracts			2,200			2,309
Interest and other financing charges on short term debt, net			(312)			(1,493)
Interest and other financing charges on long term debt			(17,978)			(36,064)
Currency exchange gain (loss)			(2,548)			(8,619)
Large corporations tax recovery (expense) and other tax			242			218
Future income tax reduction			15,084			20,049
Net Income (loss)			$ 18,203			$ (21,036)
Total Assets(3)	$ 1,253,553	$ 3,504,919	$ 4,758,472	$ 1,253,553	$ 3,504,919	$ 4,758,472
Capital Expenditures						
Development and other activity	$ 8,459	$ 52,314	$ 60,773	$ 17,142	$ 65,843	$ 182,985
Property acquisitions (dispositions), net	-	(726)	(726)	-	30,236	30,236
Total expenditures	$ 8,459	$ 51,588	$ 60,047	$ 17,142	$ 196,079	$ 213,221
Property, plant and equipment						
Cost	$ 1,145,792	$ 3,187,974	$ 4,333,766	$ 1,145,792	$ 3,187,974	$ 4,333,766
Accumulated depletion, depreciation, and amortization	(41,766)	(221,163)	(262,929)	(41,766)	(221,163)	(262,929)
Net book value	$ 1,104,026	$ 2,966,811	$ 4,070,837	$ 1,104,026	$ 2,966,811	$ 4,070,837
Goodwill						
Beginning of period	$ -	$ 404,943	$ 404,943	$ -	$ 404,943	$ 404,943
Addition (reduction) to goodwill	-	-	-	-	-	-
Impairment of goodwill	-	-	-	-	-	-
End of period	$ -	$ 404,943	$ 404,943	$ -	$ 404,943	$ 404,943

(1) Accounting policies for segments are the same as those described in Note 2 above.
(2) Of the total downstream revenue, two customers represent sales of $655.4 million and $0.1 million for the three months ended June 30, 2010; and $826.8million and $41.6 million for the six months ended June 30, 2010. No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Total assets on a consolidated basis includes $0.3 million relating to the fair value of risk management contracts and nil relating to future income tax.
(4) There is no intersegment activity.

17. Commitments and Contingencies

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 June 30, 2010:

(a) The downstream operations have a supply and offtake agreement with Vitol for a primary term to October 31, 2011 after which the agreement will revert to an evergreen arrangement. This agreement continues to provide that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that Vitol 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. At June 30, 2010, the downstream operations had commitments totaling approximately $502.5 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

(b) The downstream operations have 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 $3.4 million; costs cannot yet be estimated for the remaining projects.

(c) A subsidiary of the Company 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 the Company in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to the Company is not determinable at this time and no amounts are accrued in the consolidated financial statements in respect of this matter. The Company is indemnified by Vitol Group B.V. in respect of this contingent liability.

(d) Suncor Energy, a former owner of the North Atlantic refinery in the downstream operations, 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 the Company'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 to 2012, while the rights in paragraph (iii) continue until amended by the parties.

(e) On January 7, 2010 the downstream operations experienced a fire at the refinery in the conversion section of the operating units. As a result, the refinery was shut-down for assessment and repairs for approximately ten weeks. Harvest will be submitting an insurance claim to the company's insurers relating to the business interruption loss. As Harvest is currently in the process of preparing and estimating the claim, no estimate of the net proceeds can be provided at this time.

(f) 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 the Company's 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 Harvest has filed a Notice of Appeal with the Tax Court. The CRA and Harvest have attended the examinations for discovery in April 2010; the undertakings, which are mutual requests for additional information, have been completed on both sides

The following is a summary of Harvest's contractual obligations and commitments as at June 30, 2010:

	Payments Due by Period						
	2010	2011	2012	2013	2014	Thereafter	Total
Debt repayments	23,810	223,104	106,796	512,969	60,050	236,599	1,163,328
Debt interest payments(1)	38,771	71,607	56,635	41,566	18,437	7,292	234,308
Capital commitments(2)	34,282	1,817	-	-	-	-	36,099
Operating leases(3)	3,769	7,374	7,256	6,288	6,131	1,446	32,264
Pension contributions(4)	2,800	4,182	4,266	4,351	4,438	4,527	24,564
Transportation agreements(6)	2,903	2,350	744	205	-	-	6,202
Feedstock commitments(7)	502,471	-	-	-	-	-	502,471
Contractual obligations	608,806	310,434	175,697	565,379	89,056	249,864	1,999,236

(1) 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.
(2) Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 14].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 17(a) above].

18. Subsequent Events

Between July 1, 2010 and August 4, 2010, an additional $267.3million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 17].

On August 4, 2010, Harvest closed on the acquisition of the BlackGold Oilsands Project ("BlackGold") from KNOC for $374 million; the acquisition will be financed with the issuance of shares to KNOC. Black Gold is located in northeastern Alberta and has existing ERCB approval for a Phase 1 project of 10,000 bpd and an application has been made for a phase 2 project that would increase production to 30,000 bpd. The project will utilize steam assisted gravity drainage (SAGD); an in situ technology that uses innovation in horizontal drilling. Harvest has committed to further development of BlackGold through construction of Phase 1; the steam generation and fluid processing facility has been committed to at a fixed cost of $312 million. Total project costs through 2010 to 2012 are estimated at $450 - $500 million with first oil expected in early 2013 at an estimated production of 10,000 bpd.

KNOC has committed to inject sufficient capital into Harvest to cover the project development for the remainder of 2010. The first transaction, expected to close on August 20, 2010, will be the issuance of 4.7 million shares at a price of $10.00 per share for a total cash consideration of $47 million.

As KNOC is the sole shareholder of Harvest, KNOC will be retaining control over BlackGold; as there is no substantive change in the ownership interest of the BlackGold assets, these assets will be recorded at the existing carrying values as previously recorded by KNOC.

On August 6th, 2010, Harvest signed a purchase and sale agreement to purchase certain petroleum and natural gas assets in exchange for $150 million in cash. The purchase of these properties is subject to due diligence and regulatory approval. The acquisition is expected to close by the fourth quarter and will have an effective date of May 1, 2010; upon completion of this purchase, the production from these properties will be included in Harvest's results. These assets have average daily production of 2,300 boe and are expected to add 500 boe/d to Harvest's 2010 average daily production.