Canadian Natural

diverse asset base | disciplined growth | strong leadership

NEWS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2008 SECOND QUARTER RESULTS CALGARY, ALBERTA – AUGUST 7, 2008 – FOR IMMEDIATE RELEASE

Commenting on second quarter results, Allan Markin, Chairman of Canadian Natural stated, “This is an exciting time for Canadian Natural. Phase 1 of our Horizon Project is approaching completion. This is a complex project which involves moving raw oil sands materials through a complex process to yield raw bitumen crude oil and then upgrading it to 34º API, light sweet synthetic crude oil. The hard work of everyone involved on the Horizon Project has produced a world class asset that will provide steady cash flow for years to come. Strong results from our conventional operations reflect the strength and depth of our existing asset base. It is a credit to our team and assets that we managed our growth profile for conventional crude oil and natural gas growth opportunities to build the Horizon Project.”

John Langille, Vice-Chairman of Canadian Natural stated, “The second quarter of 2008 saw continuing strength in both crude oil and natural gas pricing. Narrow heavy crude oil differentials combined with higher realized pricing for the quarter resulted in Q2/08 cash flow of nearly $1.86 billion. As cash flow from the Horizon Project is added to existing conventional cash flow, we will focus on further strengthening our balance sheet as well as opportunities available in our diverse asset base. Capital discipline and allocation remain priorities to ensure returns are optimized, even in a high commodity price environment.”

Steve Laut, President and Chief Operating Officer of Canadian Natural commented, “Q2/08 was a very strong quarter for us. In Q2/08 both crude oil and natural gas production in Canada exceeded the top end of our guidance, reflecting the strength of our conventional asset base. Canadian Natural has achieved a significant milestone as we proceed with the final construction, commissioning and staged start-up of the Horizon Project and begin to realize the benefits of the largest single capital project in Canadian Natural’s history. Our current schedule will see us producing first bitumen crude oil in early September, first partially upgraded crude oil by the end of September, and first 34º API, light sweet synthetic crude oil in Q4/08.

We have experienced a slippage in our targeted start-up in the production of synthetic crude oil as we have experienced delays in the completion of the primary and secondary upgrading processes. This has also resulted in increased project costs as manpower requirements have been extended longer than our planning schedule anticipated. Our current cost estimate has increased by 8% above our previous estimate bringing the total cost to 36% above our original 2004 estimate of $6.8 billion. The start-up of the Horizon Project is a major step for Canadian Natural. We continue to evolve and diversify our asset base and look forward to the continuous stream of cash flow for years to come. The result is an even stronger and more sustainable company.

As part of our three phase heavy crude oil marketing strategy, Canadian Natural has made a significant step in the second phase to secure additional markets. Canadian Natural has committed 120,000 bbl/d for 20 years to the Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to Port Arthur, Texas, which is subject to regulatory approval. Canadian Natural has also secured an option to acquire an equity interest in the Keystone Project.

Also fulfilling our defined heavy crude oil marketing plan is a 20 year 100,000 bbl/d supply arrangement with a major US refiner to supply refineries in the Gulf Coast at market prices.

The completion of both of these agreements allows Canadian Natural to proceed with increased confidence the development of Canadian Natural's vast heavy oil assets and to deliver in a methodical staged manner an incremental 325,000 bbl/d of heavy crude oil. These agreements facilitate the unlocking of the value in our vast heavy oil resource base and will create tremendous value for Canadian Natural shareholders.

We remain focused on the costs we are able to control and manage those that are outside our influence. We continue to direct our investment – of time, energy and capital – towards those projects and activities that provide the greatest return."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Net earnings (loss)	**$ (347)**	$ 727	$ 841	**$ 380**	$ 1,110
per common share, basic and diluted	**$ (0.65)**	$ 1.35	$ 1.56	**$ 0.70**	$ 2.06
Adjusted net earnings from operations (1)	**$ 960**	$ 872	$ 595	**$ 1,832**	$ 1,216
per common share, basic and diluted	**$ 1.78**	$ 1.61	$ 1.10	**$ 3.39**	$ 2.25
Cash flow from operations (2)	**$ 1,859**	$ 1,725	$ 1,513	**$ 3,584**	$ 3,135
per common share, basic and diluted	**$ 3.44**	$ 3.19	$ 2.81	**$ 6.63**	$ 5.82
Capital expenditures, net of dispositions	**$ 2,127**	$ 1,753	$ 1,460	**$ 3,880**	$ 3,469
Daily production, before royalties					
Natural gas (mmcf/d)	**1,526**	1,538	1,722	**1,532**	1,719
Crude oil and NGLs (bbl/d)	**319,077**	327,217	327,494	**323,147**	327,249
Equivalent production (boe/d)	**573,437**	583,488	614,461	**578,461**	613,790

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the MD&A.

- Natural gas production volumes for the second quarter represented 44% of the Company's total production. Natural gas production for Q2/08 averaged 1,526 mmcf/d, down slightly from 1,538 mmcf/d for Q1/08 and down 11% from 1,722 mmcf/d for Q2/07. Q2/08 saw a very successful drilling program with North America volumes exceeding corporate guidance. The decrease in volumes for Q2/08 from Q2/07 reflected continued reallocation of capital towards higher return projects in crude oil.

- Total crude oil and NGLs production for Q2/08 was 319,077 bbl/d. Q2/08 crude oil production volumes decreased 2% from Q1/08 of 327,217 bbl/d, and decreased 3% from Q2/07 of 327,494 bbl/d. Volumes in Q2/08 reflect the transition between steam and production cycles for Primrose thermal wells, continued conversion of production wells to polymer injection wells at Pelican Lake, along with turnarounds in the North Sea.

- Quarterly cash flow from operations was nearly $1.86 billion, an 8% increase from Q1/08 and an increase of 23% from Q2/07. The increase from Q2/07 primarily reflected higher crude oil and natural gas realizations, partially offset by realized risk management losses.

- Quarterly net loss for Q2/08 was $347 million primarily as a result of risk management losses. Quarterly adjusted net earnings from operations for Q2/08 were $960 million primarily due to higher product prices.

- Maintained a strong undeveloped conventional core land base in Canada of 11.4 million net acres - a key asset for continued value growth.

- Improvements at the Pelican Lake Field continue with the conversion of water flood wells to polymer flood wells, with a daily average of approximately 37,000 bbl/d.

- The Primrose East Expansion, which is targeted to add 40,000 bbl/d of capacity, has made significant progress. First steam is scheduled for September, coming in ahead of schedule, with first production targeted for Q4/08 versus a previous target of Q1/09.
- Drilling has started at Baobab in Offshore Côte d'Ivoire. The equipment was mobilized in early Q2/08, enabling work to begin on the restoration of shut-in production. It is targeted that a minimum 3 of the 5 Baobab wells will come on stream over the course of 2008 and 2009.
- The Olowi Project in Offshore Gabon continues on schedule with first crude oil production targeted for late 2008.
- Construction and commissioning of the Horizon Oil Sands Project ("Horizon Project") continued in Q2/08 with first bitumen crude oil production targeted for early September, partially upgraded crude oil production targeted for the end of September, and first 34º API, light sweet synthetic crude oil production ("SCO") in Q4/08.
- Committed to ship 120,000 bbl/d of heavy crude oil for 20 years on the proposed Keystone pipeline US Gulf Coast expansion from Hardisty, Alberta to Port Arthur, Texas.
- Committed to a 100,000 bbl/d heavy crude oil supply agreement with a major US refiner to supply refineries in the Gulf Coast at market prices for 20 years.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable October 1, 2008.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Undeveloped land is critical to the Company's ongoing growth and development within these core regions. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil, heavy crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Jun 30, 2008 (thousands of net acres)	**Drilling activity six months ended Jun 30, 2008 (net wells) (1)**
Canadian conventional		
Northeast British Columbia	**2,318**	**21.8**
Northwest Alberta	**1,428**	**53.9**
Northern Plains	**6,635**	**252.1**
Southern Plains	**863**	**68.8**
Southeast Saskatchewan	**123**	**19.4**
In-situ Oil Sands	**483**	**53.0**
	11,850	**469.0**
Horizon Oil Sands Project	**115**	**-**
United Kingdom North Sea	**268**	**4.1**
Offshore West Africa	**206**	**1.5**
	12,439	**474.6**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2008		2007	
	Gross	**Net**	Gross	Net
Crude oil	**284**	**266**	290	271
Natural gas	**202**	**166**	254	207
Dry	**20**	**17**	74	64
Subtotal	**506**	**449**	618	542
Stratigraphic test / service wells	**26**	**26**	241	241
Total	**532**	**475**	859	783
Success rate (excluding stratigraphic test / service wells)		**96%**		88%

North America Conventional

North America natural gas

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Natural gas production (mmcf/d)	**1,501**	1,513	1,696	**1,507**	1,694
Net wells targeting natural gas	**8**	167	7	**175**	252
Net successful wells drilled	**5**	161	6	**166**	207
Success rate	**63%**	96%	86%	**95%**	82%

- Q2/08 North America natural gas production decreased marginally from Q1/08 and decreased 11% from Q2/07. The year over year decrease reflected natural declines in base production and the Company's strategic decision to reduce spending on natural gas drilling. However, it was a very successful quarter with volumes exceeding quarterly guidance targets.
- Canadian Natural targeted 8 net natural gas wells in Q2/08. In Northeast British Columbia, 2 net wells were drilled, while in Northwest Alberta, 1 net well was drilled. In the Northern Plains, 4 net wells were drilled, with 1 net well drilled in the Southern Plains.
- Planned drilling activity for Q3/08 includes 81 natural gas wells compared to drilling activity for Q3/07 of 106 natural gas wells.
- Inflationary pressure continues to affect capital and service costs for natural gas drilling. Cost control and maximizing shareholder value remain priorities within this business environment.

North America crude oil and NGLs

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs production (bbl/d)	**245,616**	248,960	240,420	**247,288**	238,962
Net wells targeting crude oil	**94**	176	78	**270**	285
Net successful wells drilled	**92**	171	75	**263**	266
Success rate	**98%**	97%	96%	**97%**	93%

- Q2/08 North America crude oil and NGLs production decreased marginally from Q1/08 and increased 2% from Q2/07 levels. The majority of the incremental production volume from Q2/07 was contributed by thermal crude oil. The decrease from Q1/08 is a reflection of transitioning off the production cycle peaks at Primrose pads.
- The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is targeted to add approximately 40,000 bbl/d of crude oil. Drilling is complete and facility construction is ahead of schedule, with production targeted to commence in late 2008 versus the previous production target of Q1/09. Primrose East is the second phase of the 325,000 bbl/d thermal growth expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.

- In early 2007, Canadian Natural announced its proposed third phase of the thermal growth plan with a development plan for the 45,000 bbl/d Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche in the Regional Municipality of Wood Buffalo. The Company has filed its formal regulatory application documents for this project as part of the Company's normal course of business.
- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout Q2/08. In Q2/08, the Company drilled 32 horizontal wells with plans to drill an additional 57 horizontal wells and 1 vertical service well throughout the remainder of 2008. Pelican Lake production averaged approximately 37,000 bbl/d for Q2/08 compared to approximately 34,000 bbl/d for Q2/07 and approximately 37,000 bbl/d for Q1/08. The response from the polymer flood project continues to be positive and the Company is moving forward on converting regions currently under waterflood to polymer flood and expanding the polymer flood to new areas.
- Conventional heavy crude oil production volumes remained constant in Q2/08 compared to Q1/08, with volumes as expected.
- During Q2/08, drilling activity targeted 94 net wells including 40 wells targeting heavy crude oil, 32 wells targeting Pelican Lake crude oil, 14 wells targeting thermal crude oil and 8 wells targeting light crude oil.
- Planned drilling activity for Q3/08 includes 256 net crude oil wells, excluding stratigraphic test and service wells.
- Inflationary pressure continues to affect capital and service costs for crude oil drilling. Cost control and maximizing shareholder value remain priorities within this business environment.

International

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil production (bbl/d)					
North Sea	**45,830**	49,568	57,286	**47,699**	59,565
Offshore West Africa	**27,631**	28,689	29,788	**28,160**	28,722
Natural gas production (mmcf/d)					
North Sea	**10**	11	15	**11**	15
Offshore West Africa	**15**	14	11	**14**	10
Net wells targeting crude oil	**1.6**	2.2	3.1	**3.8**	5.1
Net successful wells drilled	**0.8**	2.2	3.1	**3.0**	5.1
Success rate	**50%**	100%	100%	**79%**	100%

North Sea

- During Q2/08, 2.4 net wells were drilled including 0.8 net injection wells. At the end of the quarter 0.9 net crude oil wells were in progress. Crude oil production was down 8% in Q2/08 to 45,830 bbl/d from 49,568 bbl/d in Q1/08 as a result of a planned shutdown for maintenance at Ninian.
- Focus on waterflood optimization at Ninian continued with one new water injection well being completed in Q2/08, increasing water injection capacity. Compared to the first six months of last year the Company has increased water injection by 25%.
- At Murchison, the second of two production wells planned for 2008 was completed in the quarter.
- During the quarter, an unsuccessful exploration well was drilled on the Anning prospect which lies in proximity of the Murchison Field.

Offshore West Africa

- Offshore West Africa's crude oil production was down 4% in Q2/08 to 27,631 bbl/d from 28,689 bbl/d in Q1/08 with stable production at Espoir and Baobab during the quarter.
- Progress on the Facility Upgrade Project at Espoir to increase capacity of the Floating, Production, Storage and Offtake Vessel ("FPSO") continues to progress ahead of schedule and is still expected to be completed in Q3/09, an acceleration of 3 to 6 months from the original estimate.
- The deep water drilling rig for Baobab was mobilized early in Q2/08, enabling work to begin on the restoration of shut-in production. It is targeted that a minimum 3 of the 5 shut-in Baobab wells be on stream over the course of 2008 and 2009.
- At the Olowi project in Offshore Gabon, a drilling rig was mobilized and drilling commenced in early May of this year with first crude oil production targeted for late 2008.
- Capital spending in Offshore West Africa is expected to increase $250 million in 2008 primarily due to early delivery of the second wellhead tower and minor scope changes for pipeline heating at Olowi.

Horizon Project

- Canadian Natural has achieved a significant milestone, entering the final construction, commissioning and staged start-up of the Horizon Project. There are seven stages to the start-up and the associated targeted start-up dates are as follows:
  - **Stage 1** – Mining. The mining operation has been ready for operation since May, and continues to move overburden. The mining team awaits the call for first oil sands delivery.
  - **Stage 2** – Steam Supply. Utility plants have been supplying low, medium and high pressure steam in stages, with the last steam (high pressure) delivered in the third week of July for testing and commissioning purposes.
  - **Stage 3 –** Bitumen Crude Oil Production. Bitumen crude oil production operations are in the final stages of commissioning with first bitumen crude oil production targeted for early September.
  - **Stage 4 –** Electricity Generation. The Co-generation Plant is targeted to deliver full load electricity in the second half of September.
  - **Stage 5 –** Sulphur Plant/Sour Gas Treating. The Sulphur Plant is targeted to be ready to receive sour gas feed mid-August and circulate amine, awaiting the first delivery of sour gas.
  - **Stage 6 –** Partially Upgraded Crude Oil Production. The Delayed Coker/Diluent Recovery Unit Plants are in the commissioning stage concurrent with the completion of final task lists (i.e. punch-lists), and are targeted to deliver partially upgraded crude oil to intermediate tanks by the end of September.
  - **Stage 7** – 34° API, Light Sweet SCO Production. The Naphtha Hydrotreating Plant (Unit 41) is completing loop checks and insulation concurrent with commissioning. First product output is currently targeted for October. The Gas Oil Hydrotreating Plant (Unit 43) is completing punch-lists, loop checks, electrical heat tracing and insulation concurrent with commissioning with first product output currently targeted for Q4/08. First, 34° API, light sweet SCO in the sales pipeline is currently targeted for Q4/08. Capacity is targeted to be 70,000 bbl/d, meeting scheduled product ramp-up. The Distillate Hydrotreating Plant (Unit 42) is finishing mechanical completion, and completing electrical heat tracing, insulation and loop checks, and currently targeted first product output is for the latter part of Q4/08. Facility capacity will be targeted to be 110,000 bbl/d of 34° API, light sweet SCO upon Plant 42 completion, ramping up production to facility capacity and maintaining the previous production ramp-up schedule.
- During the second quarter, Canadian Natural completed a majority of the pre-commissioning activity, commissioned another shovel and 12 more trucks in the mine, brought on Utilities (air, water, steam, power and natural gas), and commenced operating several of the bitumen crude oil production plants on water as a "wet run" before the introduction of oil sands.
- Pre start-up safety reviews are taking longer to complete than originally anticipated, however, the Company is remaining disciplined and will not put the facilities and personnel at risk.

- Significant progress was made but the Company has found that testing and closing of all safety and operations punch-lists are taking longer than expected. 42% of the over 800 plant systems were turned over to operations at the end of the quarter. Progress by major plant facility shows:
  - **Mining** – Completed, ready to mine oil sands and continues to move overburden
  - **Ore Preparation Plant** – Completed, targeted to receive first oil sands in August
  - **Hydrotransport** – Completed, ready to accept slurry
  - **Piperack** – Completed, live and operational
  - **Extraction** – Completed, ready for operation
  - **Froth Treatment** – Targeted to be complete by August
  - **Delayed Coker/Diluent Recovery Unit** – Commissioning well underway
  - **Hydrogen Plant** – Completed, turned over to operations
  - **Hydrotreaters** – Plant 41 and 43 completing loop checks, Plant 42 encountering some scheduling issues
  - **Co-generation** – Completed, producing steam
  - **Sulphur Plant** – Completed, turned over to operations
  - **Tankage** – Completed, ready for first oil
  - **Main Control Room** – Completed, live and fully operational
  - **Utilities & Services** – Completed, live and fully operational
  - **SCO Pipeline** (third party owned and operated) – Completed, ready to accept product, with terminaling facilities in Edmonton arranged
- Many challenges continue to be faced, with the critical path item being the completion and turnover of all three Hydrotreaters in a small window. The Distillate and Gas Oil Hydrotreater units have encountered delays and schedule slippage resulting in commissioning beyond the third quarter. The operations team has developed an overall start-up scenario for initial operation at approximately 60% of the design rate until the Distillate Hydrotreater is commissioned to mitigate any impact to overall production ramp-up.
- After the thorough monthly review in the second half of July 2008, it was determined that there was schedule slippage in Upgrading/Hydrotreating Plants and it is taking longer to complete testing, reinstatement and pre-commissioning activities of these plants.
- A detailed review of the current cost estimate indicates that the Horizon Project targeted final cost will increase by approximately 8% or approximately $525 million above the previous construction cost estimates bringing the total cost estimate of the Horizon Project to approximately 36% above our original 2004 $6.8 billion estimate, or approximately $9.27 billion (up from the previous total cost estimate of $8.74 billion). This increase will result in a targeted on-stream cost of $84,000 bbl/d of capacity, including the benefits of the significant pre-build capital invested for Phase 2/3.
- With primary focus on completing Phase 1 and producing SCO, Canadian Natural has a team working on future expansions. Several long lead items for Phase 2/3 expansions are on site, including the coke drums and hydrotreating reactors. The reactors have been assembled on site and hydrotested. The Company has awarded nearly all the Engineering (detailed design) and Procurement contracts for the Tranche 2 scope and have held kick-off meetings with the majority of the contractors.
- Canadian Natural is managing its commitment to safety and celebrated over 20 million manhours without a lost time incident – more than 1 year. Along with systems and start-up training for a significant number of staff, the Company has completed its ‘Going Live’ safety orientation for all Horizon Project employees and contractors. The Pre Start-Up Safety Reviews have been initiated in all plants and the learnings from earlier system turnovers are being applied.
- For further details, refer to the Horizon Oil Sands Project update from August 6, 2008.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 124.00**	$ 97.96	$ 65.02	**$ 110.98**	$ 61.64
Western Canadian Select blend differential[2] from WTI (%)	**17%**	22%	29%	**19%**	28%
Corporate average pricing before risk management (C$/bbl)	**$ 103.73**	$ 78.99	$ 53.74	**$ 91.11**	$ 52.72
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 8.86**	$ 6.76	$ 6.99	**$ 7.81**	$ 7.03
Corporate average pricing before risk management (C$/mcf)	**$ 9.89**	$ 7.77	$ 7.44	**$ 8.83**	$ 7.59

(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.

(2) Beginning in Q1 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

- In Q2/08, the WCS heavy crude oil differential as a percent of WTI was 17%, compared to 22% in Q1/08. Heavy crude oil differentials improved in Q2/08 due to a strong worldwide demand for diesel and low crack spreads, with overall high demand for crude oil products. Combined with declining heavy crude oil production in Mexico, and increased Venezuelan supply shipments to the Asian markets, demand has been strong for Canadian heavy crude oil.

- The Company continues its efforts with other industry players to find new markets and to ease the logistical constraints in getting Western Canadian heavy crude oil to new markets, such as the US Gulf Coast. Plans were recently announced to expand the Keystone crude oil pipeline system providing additional capacity to the US Gulf Coast by 2012. Canadian Natural sees this as an important step in its marketing strategy by allowing Canadian heavy crude oil into the US Gulf Coast market and as such has committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion, which is subject to regulatory approval, for a 20 year period. The agreement also includes an option for Canadian Natural to acquire an equity interest of the Keystone Pipeline.

- Canadian Natural has also entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries. These agreements represent a step forward in the defined marketing plan of Canadian Natural to improve the margins on the Company's heavy crude oil production and to reduce the volatility historically experienced in the heavy crude oil market. With the Keystone agreement, Canadian Natural will retain full ownership of the resource while gaining access to a key market for Canadian heavy crude oil. The refining capacity in the US Gulf Coast area is approximately 7.5 million bbl/d. The long term supply agreement with a US refiner, which is contingent on the completion of the Keystone Pipeline US Gulf Coast Expansion, ensures a customer at the end of the Keystone Pipeline for a large portion of Canadian Natural's heavy crude oil that is shipped at prevailing US Gulf Coast heavy oil market prices at the points of delivery.

- The Company sees this as a strategic component to its heavy crude oil development which targets an increase to heavy crude oil production capacity from just over 200,000 bbl/d today, to over 500,000 bbl/d over the course of the next 15 years. Canadian heavy crude oil is very competitive against other international grades available in the US Gulf Coast. For Q2/08, the differential for the heavy crude oil marker, Mayan grade, was US$21.00/bbl or 17%.

- During Q2/08, the Company contributed approximately 158,000 bbl/d of its heavy crude oil streams to the WCS blend as market conditions resulted in this strategy offering the optimal pricing for bitumen crude oil.

- Natural gas pricing for Q2/08 was strong as demand for natural gas increased more than expected during the quarter. The quarter also saw fewer imports of liquefied natural gas to North America as a result of stronger pricing in Europe and Asia, again resulting in decreased supply to North America.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position to profitably grow its conventional crude oil and natural gas operations over the next several years and to build the financial capacity to complete the Horizon Project and other major projects. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced in excess of 573,000 boe/d in Q2/08, comprised of approximately 44% natural gas and 56% crude oil - with 95% of production located in G8 countries with stable and secure economies.
  - Financial stability and liquidity - cash flow from operations of $1.86 billion for Q2/08, available unused bank lines of $2.7 billion at June 30, 2008 and access to capital debt markets supported by strong credit ratings.
  - Reduced volatility of commodity prices - a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program throughout the Horizon Project.
  - A strengthening balance sheet with debt to book capitalization of 45% and debt to EBITDA of 1.6 times, both within targeted ranges.
- Commencing January 1, 2009, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters. The current program allows for hedging of 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production, and up to 25% of the expected production in months 25 to 48. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects.
- In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company is currently awaiting finalization and government approval of the royalty regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable October 1, 2008.

OUTLOOK

The Company forecasts 2008 production levels before royalties to average between 1,482 and 1,511 mmcf/d of natural gas and between 308,000 and 350,000 bbl/d of crude oil and NGLs. Q3/08 production guidance before royalties is forecast to average between 1,466 and 1,490 mmcf/d of natural gas and between 299,000 and 316,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/.

Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures and other 2008 guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitutes forward-looking statements. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurance that the plans, initiatives or expectations upon which they are based will occur.

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (the "Company") and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete its capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and at times in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the six and three months ended June 30, 2008 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations and cash flow from operations. These financial measures are not defined by GAAP and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with GAAP, as an indication of the Company's performance. The measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings in the "Financial Highlights" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices exclude the effect of risk management activities and transportation and blending costs, except where noted otherwise. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the six and three months ended June 30, 2008 in relation to the comparable periods in 2007 and the first quarter of 2008. The accompanying tables form an integral part of this MD&A. This MD&A is dated August 6, 2008. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Revenue, before royalties	**$ 5,112**	$ 3,967	$ 3,152	**$ 9,079**	$ 6,270
Net earnings (loss)	**$ (347)**	$ 727	$ 841	**$ 380**	$ 1,110
Per common share – basic and diluted	**$ (0.65)**	$ 1.35	$ 1.56	**$ 0.70**	$ 2.06
Adjusted net earnings from operations (1)	**$ 960**	$ 872	$ 595	**$ 1,832**	$ 1,216
Per common share – basic and diluted	**$ 1.78**	$ 1.61	$ 1.10	**$ 3.39**	$ 2.25
Cash flow from operations (2)	**$ 1,859**	$ 1,725	$ 1,513	**$ 3,584**	$ 3,135
Per common share – basic and diluted	**$ 3.44**	$ 3.19	$ 2.81	**$ 6.63**	$ 5.82
Capital expenditures, net of dispositions	**$ 2,127**	$ 1,753	$ 1,460	**$ 3,880**	$ 3,469

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	*Three Months Ended*			*Six Months Ended*	
	Jun 30 2008	*Mar 31 2008*	*Jun 30 2007*	***Jun 30 2008***	*Jun 30 2007*
Net earnings (loss) as reported	***$ (347)***	*$ 727*	*$ 841*	***$ 380***	*$ 1,110*
Stock-based compensation expense, net of tax (a)	***328***	*-*	*74*	***328***	*91*
Unrealized risk management loss (gain), net of tax (b)	***997***	*76*	*(35)*	***1,073***	*327*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(18)***	*110*	*(214)*	***92***	*(241)*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	***-***	*(41)*	*(71)*	***(41)***	*(71)*
Adjusted net earnings from operations	***$ 960***	*$ 872*	*$ 595*	***$ 1,832***	*$ 1,216*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized as part of the Horizon Oil Sands Project during the construction period.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swaps, and are recognized in net earnings.

(d) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes in the first quarter of 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa. Income tax rate changes in the second quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $71 million in North America.

Cash Flow from Operations

	Three Months Ended			Six Months Ended	
($ millions)	***Jun 30 2008***	*Mar 31 2008*	*Jun 30 2007*	***Jun 30 2008***	*Jun 30 2007*
Net earnings (loss)	***$ (347)***	*$ 727*	*$ 841*	***$ 380***	*$ 1,110*
Non-cash items:					
Depletion, depreciation and amortization	***670***	*688*	*720*	***1,358***	*1,429*
Asset retirement obligation accretion	***17***	*17*	*17*	***34***	*35*
Stock-based compensation expense	***459***	*-*	*106*	***459***	*131*
Unrealized risk management loss (gain)	***1,415***	*108*	*(57)*	***1,523***	*479*
Unrealized foreign exchange (gain) loss	***(20)***	*126*	*(250)*	***106***	*(282)*
Deferred petroleum revenue tax (recovery) expense	***(34)***	*(21)*	*20*	***(55)***	*17*
Future income tax (recovery) expense	***(301)***	*80*	*116*	***(221)***	*216*
Cash flow from operations	***$ 1,859***	*$ 1,725*	*$ 1,513*	***$ 3,584***	*$ 3,135*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2008 were $380 million compared to $1,110 million for the six months ended June 30, 2007. Net earnings for the six months ended June 30, 2008 included net unrealized after-tax expenses of $1,452 million related to the effects of risk management activities, fluctuations in foreign exchange rates, fluctuations in stock-based compensation expense and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax expenses of $106 million for the six months ended June 30, 2007. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2008 increased to a record $1,832 million compared to $1,216 million for the six months ended June 30, 2007. The increase in adjusted net earnings from the comparable period in 2007 was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, lower interest expense, and lower administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar.

The net loss for the second quarter of 2008 was $347 million compared to net earnings of $841 million for the second quarter of 2007 and net earnings of $727 million for the prior quarter. The net loss for the second quarter of 2008 included net unrealized after-tax expenses of $1,307 million related to the effects of risk management activities, fluctuations in foreign exchange rates, and fluctuations in stock-based compensation expense, compared to net unrealized after-tax income of $246 million for the second quarter of 2007 and net unrealized after-tax expenses of $145 million for the prior quarter, which also included the impact of statutory tax rate changes on future income tax liabilities. Excluding these items, adjusted net earnings from operations for the second quarter of 2008 increased to a record $960 million compared to $595 million for the second quarter of 2007 and $872 million for the prior quarter. The increase in adjusted net earnings from the second quarter of 2007 and the prior quarter was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, lower interest expense, and lower administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, and lower sales volumes. The increase in adjusted net earnings from the second quarter of 2007 was also partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

The impacts of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates are expected to continue to contribute to significant quarterly volatility in consolidated net earnings.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This program currently allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of put options is in addition to the above parameters. In accordance with the policy, approximately 57% of budgeted crude oil volumes are hedged for the remainder of 2008, approximately 18% of budgeted natural gas volumes are hedged for the third quarter of 2008 and approximately 6% of estimated crude oil volumes are hedged for 2009. In addition, 50,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2008 at a strike price of US$55.00 per bbl, 50,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$80.00 per bbl, and 42,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$100.00 per bbl. Subsequent to June 30, 2008, the Company unwound 50,000 bbl/d of US$80.00 WTI put options and entered into 50,000 bbl/d of US$100.00 WTI put options for the period January to December 2009.

Commencing January 1, 2009, following the planned completion of Phase 1 of the Horizon Project, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters.

The Company's outstanding commodity related financial derivatives as at June 30, 2008 are detailed in the "Liquidity and Capital Resources" section of this MD&A.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at June 30, 2008.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,523 million ($1,073 million after-tax) on its commodity risk management activities for the six months ended June 30, 2008, including a $1,415 million ($997 million after-tax) unrealized loss for the three months ended June 30, 2008. Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects. For further details, refer to the "Risk Management Activities" section of this MD&A.

Subsequent to June 30, 2008, prevailing forward commodity prices declined. Based on forward pricing as at July 31, 2008 and including the effects of July 2008 settlements, unrealized risk management losses as at June 30, 2008 would have decreased by approximately $680 million ($480 million after-tax).

The Company recorded a $459 million ($328 million after-tax) stock-based compensation expense for the six and three months ended June 30, 2008 as a result of the increase in the Company's share price (Company's share price as at: June 30, 2008 – C$100.84; March 31, 2008 – C$70.27; December 31, 2007 – C$72.58; June 30, 2007 – C$70.78). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect the changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability at June 30, 2008 reflected the Company's potential cash liability should vested options be surrendered for a cash payout at the market price on June 30, 2008. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the six months ended June 30, 2008 increased to a record $3,584 million compared to $3,135 million for the six months ended June 30, 2007. The increase from the comparable period in 2007 was primarily due to the impact of higher realized pricing, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar.

Cash flow from operations for the second quarter of 2008 increased to a record $1,859 million compared to $1,513 million for the second quarter of 2007 and $1,725 million for the prior quarter. The increase from the second quarter of 2007 was primarily due to the impact of higher realized pricing, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily due to the impact of higher realized pricing, partially offset by higher realized risk management losses, and higher royalty and production expense.

Total production before royalties for the six months ended June 30, 2008 decreased 6% to average 578,461 boe/d from 613,790 boe/d for the six months ended June 30, 2007. Production for the second quarter of 2008 decreased 7% to 573,437 boe/d from 614,461 boe/d for the second quarter of 2007 and 2% from 583,488 boe/d for the prior quarter. Total production for the second quarter of 2008 was at the high end of the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Jun 30 2008**		Mar 31 2008		Dec 31 2007		Sep 30 2007
Revenue, before royalties	**$**	**5,112**	$	3,967	$	3,200	$	3,073
Net earnings (loss)	**$**	**(347)**	$	727	$	798	$	700
Net earnings (loss) per common share								
– Basic and diluted	**$**	**(0.65)**	$	1.35	$	1.48	$	1.30

($ millions, except per common share amounts)		Jun 30 2007		Mar 31 2007		Dec 31 2006		Sep 30 2006
Revenue, before royalties	$	3,152	$	3,118	$	2,826	$	3,108
Net earnings	$	841	$	269	$	313	$	1,116
Net earnings per common share								
– Basic and diluted	$	1.56	$	0.50	$	0.58	$	2.08

Net earnings (loss) over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, fluctuations in sales volumes, the impact of mark-to-market accounting of financial instruments and stock-based compensation, fluctuations in depletion, depreciation and amortization charges, fluctuations in foreign exchange rates, and adjustments to future income tax liabilities due to statutory tax rate and other legislative changes. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing

  Crude oil prices reflected demand growth, continued geopolitical uncertainties and fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.

- Natural gas pricing

  Natural gas prices primarily reflected seasonal fluctuations in both the demand for natural gas and inventory storage levels and fluctuations in liquefied natural gas imports into the US.

- Crude oil and NGLs sales volumes

  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, development of Espoir, and additional sales volumes from the Anadarko Canada Corporation ("ACC") acquisition completed in the fourth quarter of 2006. Crude oil and NGLs sales volumes also reflected fluctuations in production from the North Sea due to timing of maintenance activities and liftings and the impact of shut-in Baobab production in Offshore West Africa.

- Natural gas sales volumes

  Natural gas sales volumes primarily reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increases were partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity.

- Foreign exchange rates

  A general strengthening of the Canadian dollar relative to the US dollar has decreased the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt balances and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swaps.

- Risk management

  Net earnings have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market of the Company's risk management activities.

- Changes in income tax expense

  Income tax expense fluctuations include statutory tax rate and other legislative changes enacted or substantively enacted in the various periods.

- Stock-based compensation

  Net earnings have fluctuated due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price over the eight most recently completed quarters.

- Production expense

  Production expense has fluctuated company wide primarily due to the impact for the demand for services, industry-wide inflationary cost pressures experienced in prior years in all segments, fluctuations in product mix, and the impact of seasonal costs that are dependent on weather.

- Depletion, depreciation and amortization

  Depletion, depreciation and amortization expense has fluctuated due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition.

OPERATING HIGHLIGHTS

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 103.73**	$ 78.99	$ 53.74	**$ 91.11**	$ 52.72
Royalties	**14.82**	8.70	5.46	**11.70**	5.19
Production expense	**16.39**	14.81	15.01	**15.58**	14.40
Netback	**$ 72.52**	$ 55.48	$ 33.27	**$ 63.83**	$ 33.13
Natural gas ($/mcf) [1]					
Sales price [2]	**$ 9.89**	$ 7.77	$ 7.44	**$ 8.83**	$ 7.59
Royalties	**1.86**	1.35	1.10	**1.60**	1.29
Production expense	**0.94**	1.03	0.89	**0.98**	0.93
Netback	**$ 7.09**	$ 5.39	$ 5.45	**$ 6.25**	$ 5.37
Barrels of oil equivalent ($/boe) [1]					
Sales price [2]	**$ 84.88**	$ 65.09	$ 49.70	**$ 74.86**	$ 49.50
Royalties	**13.26**	8.43	5.99	**10.82**	6.37
Production expense	**11.60**	11.02	10.44	**11.31**	10.27
Netback	**$ 60.02**	$ 45.64	$ 33.27	**$ 52.73**	$ 32.86

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
WTI benchmark price (US$/bbl)	**$ 124.00**	$ 97.96	$ 65.02	**$ 110.98**	$ 61.64
Dated Brent benchmark price (US$/bbl)	**$ 121.39**	$ 96.94	$ 68.74	**$ 109.17**	$ 63.28
WCS blend differential from WTI (US$/bbl) (1)	**$ 21.62**	$ 21.41	$ 19.17	**$ 21.51**	$ 17.33
WCS blend differential from WTI (%) (1)	**17%**	22%	29%	**19%**	28%
Condensate benchmark price (US$/bbl)	**$ 124.64**	$ 98.40	$ 65.66	**$ 111.52**	$ 62.28
NYMEX benchmark price (US$/mmbtu)	**$ 10.80**	$ 8.07	$ 7.56	**$ 9.44**	$ 7.26
AECO benchmark price (C$/GJ)	**$ 8.86**	$ 6.76	$ 6.99	**$ 7.81**	$ 7.03
US / Canadian dollar average exchange rate	**$ 0.9900**	$ 0.9958	$ 0.9112	**$ 0.9929**	$ 0.8812

(1) Beginning in the first quarter of 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$110.98 per bbl for the six months ended June 30, 2008, an increase of 80% from US$61.64 per bbl for the six months ended June 30, 2007. WTI averaged US$124.00 per bbl for the second quarter of 2008, an increase of 91% from US$65.02 per bbl for the second quarter of 2007, and an increase of 27% from US$97.96 per bbl for the prior quarter. WTI pricing during the second quarter of 2008 generally reflected continued strong demand for crude oil and continued geopolitical events resulting in increased market uncertainty and limited supply.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which generally continued to benefit from strong European and Asian demand. Brent averaged US$109.17 per bbl for the six months ended June 30, 2008, an increase of 73% compared to US$63.28 per bbl for the six months ended June 30, 2007. In the second quarter of 2008, Brent averaged US$121.39 per bbl, an increase of 77% compared to US$68.74 per bbl for the second quarter of 2007, and an increase of 25% from US$96.94 per bbl for the prior quarter.

The Company's realized crude oil prices increased from the six months ended June 30, 2007 primarily as a result of increased WTI and Brent pricing and a narrower Heavy Differential, offset by the impact of a strong Canadian dollar. The Heavy Differential averaged 19% for the six months ended June 30, 2008 compared to 28% for the six months ended June 30, 2007. For the second quarter of 2008, the Heavy Differential averaged 17% compared to 29% for the second quarter of 2007, and 22% for the prior quarter. The narrowing of the Heavy Differential from the prior period was primarily due to increased demand for heavy crude oil due to reduced refinery cracking margins and increased demand for diesel, as well as an industry wide reduction in Canadian production of heavy crude oil. Realized prices continued to be adversely impacted by the strong Canadian dollar.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of ongoing supply and demand factors and geopolitical events. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$9.44 per mmbtu for the six months ended June 30, 2008, an increase of 30% from US$7.26 per mmbtu for the six months ended June 30, 2007. For the second quarter of 2008, NYMEX natural gas prices averaged US$10.80 per mmbtu, an increase of 43% from US$7.56 per mmbtu for the second quarter of 2007, and 34% from US$8.07 per mmbtu for the prior quarter. AECO natural gas prices for the six months ended June 30, 2008 increased 11% to average $7.81 per GJ from $7.03 per GJ for the six months ended June 30, 2007. For the second quarter of 2008, AECO natural gas prices averaged $8.86 per GJ, an increase of 27% from $6.99 per GJ in the second quarter of 2007 and 31% from $6.76 per GJ for the prior quarter. Increased natural gas prices from the comparable periods were primarily related to higher overall demand and lower storage levels, resulting from increased industrial consumption, colder weather experienced late in the first quarter of 2008, and lower liquefied natural gas imports into the US during the first half of 2008.

Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the North America crude oil and natural gas industry, particularly related to drilling activities and oil sands developments. The strong commodity price environment has also impacted costs in international basins, due in large part to the high demand for offshore drilling rigs.

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial greenhouse gas ("GHG") emissions. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, are captured under the regulations. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 – 2007) of the UK National Allocation Plan the Company operated below its CO_2 allocation. For Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with any requirement in effect from time to time.

During the first quarter of 2008, British Columbia announced a carbon tax on fuel consumed in the province. Commencing July 1, 2008, the carbon tax will be assessed at $10/tonne of CO_2e, increasing to $30/tonne by July 1, 2012.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects.

In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes include:

- The implementation of a new bitumen valuation methodology and a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing; and
- New royalty formulas for conventional crude oil and natural gas that are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

The Company is currently awaiting finalization and government approval of the royalty regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

PRODUCT PRICES

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 97.94**	$ 72.86	$ 47.20	**$ 85.31**	$ 46.66
North Sea	**$ 129.57**	$ 99.01	$ 73.18	**$ 112.75**	$ 70.84
Offshore West Africa	**$ 114.56**	$ 96.31	$ 72.84	**$ 105.51**	$ 65.34
Company average	**$ 103.73**	$ 78.99	$ 53.74	**$ 91.11**	$ 52.72
Natural gas ($/mcf) (1) (2)					
North America	**$ 9.94**	$ 7.80	$ 7.47	**$ 8.87**	$ 7.62
North Sea	**$ 4.27**	$ 3.30	$ 3.92	**$ 3.77**	$ 4.21
Offshore West Africa	**$ 8.97**	$ 7.89	$ 6.22	**$ 8.44**	$ 6.11
Company average	**$ 9.89**	$ 7.77	$ 7.44	**$ 8.83**	$ 7.59
Company average ($/boe) (1) (2)	**$ 84.88**	$ 65.09	$ 49.70	**$ 74.86**	$ 49.50
Percentage of gross revenue (2) (excluding midstream revenue)					
Crude oil and NGLs	**68%**	68%	57%	**68%**	57%
Natural gas	**32%**	32%	43%	**32%**	43%

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

The Company's realized crude oil prices increased 73% to average $91.11 per bbl for the six months ended June 30, 2008 from $52.72 per bbl for the six months ended June 30, 2007. Realized crude oil prices for the second quarter of 2008 increased 93% to average $103.73 per bbl from $53.74 per bbl for the second quarter of 2007, and increased 31% from $78.99 per bbl for the prior quarter. The Company's realized crude oil prices increased from the comparable periods in 2007 and the prior quarter primarily as a result of an increased WTI and Brent benchmark prices and a narrower Heavy Differential, partially offset by a strong Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased 16% to average $8.83 per mcf for the six months ended June 30, 2008 from $7.59 per mcf for the six months ended June 30, 2007. Realized natural gas price for the second quarter of 2008 increased 33% to average $9.89 per mcf from $7.44 per mcf for the second quarter of 2007, and increased 27% from $7.77 per mcf for the prior quarter. The increase in realized natural gas prices from the comparable periods primarily reflected increased benchmark prices due to increased industrial consumption, colder weather experienced late in the first quarter of 2008, and lower liquefied natural gas imports into the US in the first half of 2008.

North America

North America realized crude oil prices increased 83% to average $85.31 per bbl for the six months ended June 30, 2008 from $46.66 per bbl for the six months ended June 30, 2007. Realized crude oil prices increased 108% to average $97.94 per bbl for the second quarter of 2008 from $47.20 per bbl for the second quarter of 2007, and increased 34% from $72.86 per bbl for the prior quarter. The increase from the comparable periods was due to the increase in WTI benchmark pricing and a narrower Heavy Differential.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the second quarter, the Company contributed approximately 158,000 bbl/d of heavy crude oil blends to the WCS stream. Subsequent to June 30, 2008, the Company entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 and are subject to Keystone's receipt of regulatory approval of the pipeline expansion as well as minimum levels of shipper commitments.

North America realized natural gas prices increased 16% to average $8.87 per mcf for the six months ended June 30, 2008 from $7.62 per mcf for the six months ended June 30, 2007. Realized North America natural gas prices increased 33% to average $9.94 per mcf for the second quarter of 2008 from $7.47 per mcf for the second quarter of 2007, and increased 27% from $7.80 per mcf for the prior quarter. The increase in natural gas prices from the comparable periods was primarily related to the increase in benchmark prices.

Comparisons of the prices received for the Company's North America production by product type were as follows:

	Jun 30 2008	Mar 31 2008	Jun 30 2007
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	**$ 113.92**	$ 88.78	$ 63.09
Pelican Lake crude oil (C$/bbl)	**$ 98.28**	$ 72.77	$ 44.49
Primary heavy crude oil (C$/bbl)	**$ 95.39**	$ 68.61	$ 42.30
Thermal heavy crude oil (C$/bbl)	**$ 88.72**	$ 65.97	$ 41.09
Natural gas (C$/mcf)	**$ 9.94**	$ 7.80	$ 7.47

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 59% to average $112.75 per bbl for the six months ended June 30, 2008 from $70.84 per bbl for the six months ended June 30, 2007. Realized North Sea crude oil prices increased 77% to average $129.57 per bbl for the second quarter of 2008 from $73.18 per bbl for the second quarter of 2007, and by 31% from $99.01 per bbl for the prior quarter. As revenue in the North Sea is currently recognized on a liftings basis, realized crude oil prices per bbl in any particular quarter are dependant on the frequency and timing of liftings of each field. Realized crude oil prices in the North Sea during the second quarter continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the strong Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 61% to average $105.51 per bbl for the six months ended June 30, 2008 from $65.34 per bbl for the six months ended June 30, 2007. Realized Offshore West Africa crude oil prices increased 57% to average $114.56 per bbl for the second quarter of 2008 from $72.84 per bbl for the second quarter of 2007, and increased 19% from $96.31 per bbl for the prior quarter. As revenue in Offshore West Africa is recognized on a liftings basis, realized crude oil prices per bbl in any particular quarter are dependant on the frequency and timing of liftings of each field, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during the second quarter continued to benefit from the impact of strong European and Asian demand, offset by the impact of the strong Canadian dollar.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related crude oil volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Jun 30 2008**	Mar 31 2008	Dec 31 2007
North America, related to pipeline fill	**1,097,526**	1,097,526	1,097,526
North Sea, related to timing of liftings	**802,576**	637,755	1,032,723
Offshore West Africa, related to timing of liftings	**377,741**	260,649	8,578
	2,277,843	1,995,930	2,138,827

In the second quarter of 2008, an additional 282,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at June 30, 2008, reducing cash flow from operations by approximately $42 million.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs (bbl/d)					
North America	**245,616**	248,960	240,420	**247,288**	238,962
North Sea	**45,830**	49,568	57,286	**47,699**	59,565
Offshore West Africa	**27,631**	28,689	29,788	**28,160**	28,722
	319,077	327,217	327,494	**323,147**	327,249
Natural gas (mmcf/d)					
North America	**1,501**	1,513	1,696	**1,507**	1,694
North Sea	**10**	11	15	**11**	15
Offshore West Africa	**15**	14	11	**14**	10
	1,526	1,538	1,722	**1,532**	1,719
Total barrels of oil equivalent (boe/d)	**573,437**	583,488	614,461	**578,461**	613,790
Product mix					
Light/medium crude oil and NGLs	**22%**	23%	23%	**22%**	24%
Pelican Lake crude oil	**6%**	6%	6%	**6%**	5%
Primary heavy crude oil	**16%**	15%	15%	**16%**	15%
Thermal heavy crude oil	**12%**	12%	9%	**12%**	9%
Natural gas	**44%**	44%	47%	**44%**	47%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs (bbl/d)					
North America	**202,264**	216,585	206,927	**209,424**	205,671
North Sea	**45,734**	49,473	57,185	**47,603**	59,457
Offshore West Africa	**24,136**	23,496	26,876	**23,816**	26,389
	272,134	289,554	290,988	**280,843**	291,517
Natural gas (mmcf/d)					
North America	**1,227**	1,260	1,444	**1,243**	1,406
North Sea	**10**	11	15	**11**	15
Offshore West Africa	**13**	11	10	**12**	9
	1,250	1,282	1,469	**1,266**	1,430
Total barrels of oil equivalent (boe/d)	**480,418**	503,250	535,789	**491,835**	529,793

Daily production and per bbl statistics are presented throughout this MD&A on a "before royalty" or "gross" basis. Production on an "after royalty" or "net" basis is also presented.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Total production averaged 578,461 boe/d for the six months ended June 30, 2008, a 6% decrease from 613,790 boe/d for the six months ended June 30, 2007. Production for the second quarter of 2008 decreased 7% to average 573,437 boe/d, from 614,461 boe/d for the second quarter of 2007, and a 2% decrease from 583,488 boe/d for the prior quarter.

Total crude oil and NGLs production for the six months ended June 30, 2008 decreased 1% to 323,147 bbl/d from 327,249 bbl/d for the six months ended June 30, 2007. Second quarter total crude oil and NGLs production decreased 3% to 319,077 bbl/d from 327,494 bbl/d for the second quarter of 2007, and decreased 2% from 327,217 bbl/d for the prior quarter. The decrease from the comparable periods was primarily due to lower production in the North Sea. Crude oil and NGLs production in the second quarter of 2008 was at the high end of the Company's previously issued guidance of 306,000 to 323,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 44% of the Company's total production. Natural gas production for the six months ended June 30, 2008 averaged 1,532 mmcf/d compared to 1,719 mmcf/d for the six months ended June 30, 2007. Second quarter natural gas production averaged 1,526 mmcf/d compared to 1,722 mmcf/d for the second quarter of 2007 and 1,538 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods primarily reflected production declines due to the Company's strategic reduction in natural gas drilling activity. Second quarter natural gas production exceeded the Company's previously issued guidance of 1,479 to 1,513 mmcf/d.

For 2008, annual production guidance is targeted to average between 308,000 and 350,000 bbl/d of crude oil and NGLs and between 1,482 and 1,511 mmcf/d of natural gas. Third quarter 2008 production guidance is targeted to average between 299,000 and 316,000 bbl/d of crude oil and NGLs and between 1,466 and 1,490 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the six months ended June 30, 2008 increased 3% to average 247,288 bbl/d from 238,962 bbl/d for the six months ended June 30, 2007. Second quarter North America crude oil and NGLs production increased 2% to average 245,616 bbl/d from 240,420 bbl/d for the second quarter of 2007, and decreased 1% from 248,960 bbl/d for the prior quarter. The fluctuations in crude oil and NGLs production from the prior periods was primarily due to the cyclic nature of the Company’s thermal production.

For the six months ended June 30, 2008, natural gas production decreased 11% to 1,507 mmcf/d from 1,694 mmcf/d for the six months ended June 30, 2007. For the second quarter of 2008, natural gas production decreased 11% to 1,501 mmcf/d from 1,696 mmcf/d for the second quarter of 2007, and decreased marginally from 1,513 mmcf/d for the prior quarter. The decrease in natural gas production from the prior periods reflected production declines due to the Company’s strategic decision to reduce natural gas drilling activity.

North Sea

North Sea crude oil production for the six months ended June 30, 2008 decreased 20% to 47,699 bbl/d from 59,565 bbl/d for the six months ended June 30, 2007. Second quarter North Sea crude oil production decreased 20% to 45,830 bbl/d from 57,286 bbl/d for the second quarter of 2007 and by 8% from 49,568 bbl/d for the prior quarter. Second quarter production was in line with expectations, with the decrease from the prior quarter due to a planned maintenance shutdown at Ninian. Further maintenance shutdowns are planned at T-Block, Banff, and Murchison in the third quarter and at Ninian in the fourth quarter.

Offshore West Africa

Offshore West Africa crude oil production decreased 2% to 28,160 bbl/d for the six months ended June 30, 2008 from 28,722 bbl/d for the six months ended June 30, 2007. As expected, second quarter Offshore West Africa crude oil production decreased 7% to 27,631 bbl/d from 29,788 bbl/d for the second quarter of 2007, and by 4% from 28,689 bbl/d for the prior quarter. A deepwater rig commenced operations at Baobab in April 2008, which should enable the Company to execute its plan to restore certain of its shut-in production over the course of 2008 and 2009.

ROYALTIES

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 17.46**	$ 9.63	$ 6.58	**$ 13.52**	$ 6.50
North Sea	**$ 0.27**	$ 0.19	$ 0.13	**$ 0.23**	$ 0.13
Offshore West Africa	**$ 14.49**	$ 17.43	$ 7.12	**$ 15.95**	$ 5.32
Company average	**$ 14.82**	$ 8.70	$ 5.46	**$ 11.70**	$ 5.19
Natural gas ($/mcf) [1]					
North America	**$ 1.88**	$ 1.36	$ 1.11	**$ 1.62**	$ 1.30
Offshore West Africa	**$ 1.13**	$ 1.43	$ 0.59	**$ 1.28**	$ 0.50
Company average	**$ 1.86**	$ 1.35	$ 1.10	**$ 1.60**	$ 1.29
Company average ($/boe) [1]	**$ 13.26**	$ 8.43	$ 5.99	**$ 10.82**	$ 6.37
Percentage of revenue [2]					
Crude oil and NGLs	**14%**	11%	10%	**13%**	10%
Natural gas	**19%**	17%	15%	**18%**	17%
Boe	**16%**	13%	12%	**14%**	13%

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

North America

North America crude oil and NGLs royalties per bbl for the six months ended June 30, 2008 continue to reflect strong realized crude oil prices. Crude oil and NGLs royalties averaged approximately 18% of revenues for the second quarter of 2008, compared to 14% for the second quarter in 2007 and 13% in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of gross revenue for 2008.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Natural gas royalties averaged approximately 19% of revenues for the second quarter of 2008 compared to 15% for the second quarter of 2007 and 17% for the prior quarter. Natural gas royalties are anticipated to average 17% to 20% of gross revenue for 2008.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the Government State Oil Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit oil attributable to the Company's equity interest is allocated between royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Fields were fully recovered in the first quarter of 2007, increasing royalty rates and current income taxes in accordance with the terms of the PSCs.

Royalty rates as a percentage of revenue averaged approximately 13% for the second quarter of 2008 compared to 10% for the second quarter of 2007 and 18% for the prior quarter. Royalty expense in the second quarter reflected a relatively low proportion of Espoir sales in the period, which have higher royalty rates, offset by the increase in allocation of the Government's share to royalties due to the reduction in the Côte d'Ivoire corporate income tax rate enacted in the first quarter of 2008. Offshore West Africa royalty rates are anticipated to average 14% to 17% of gross revenue for 2008.

PRODUCTION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 15.44**	$ 13.88	$ 13.98	**$ 14.65**	$ 13.50
North Sea	**$ 25.61**	$ 22.35	$ 22.11	**$ 23.81**	$ 20.21
Offshore West Africa	**$ 9.79**	$ 8.03	$ 7.98	**$ 8.92**	$ 8.48
Company average	**$ 16.39**	$ 14.81	$ 15.01	**$ 15.58**	$ 14.40
Natural gas ($/mcf) [1]					
North America	**$ 0.93**	$ 1.01	$ 0.87	**$ 0.97**	$ 0.91
North Sea	**$ 2.68**	$ 2.33	$ 2.26	**$ 2.50**	$ 2.42
Offshore West Africa	**$ 1.27**	$ 1.25	$ 1.10	**$ 1.26**	$ 1.26
Company average	**$ 0.94**	$ 1.03	$ 0.89	**$ 0.98**	$ 0.93
Company average ($/boe) [1]	**$ 11.60**	$ 11.02	$ 10.44	**$ 11.31**	$ 10.27

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2008 increased 9% to $14.65 per bbl from $13.50 per bbl for the six months ended June 30, 2007. Second quarter North America crude oil and NGLs production expense increased 10% to $15.44 per bbl from $13.98 per bbl for the second quarter of 2007 and increased 11% from $13.88 per bbl for the prior quarter. The increase in production expense per bbl for the second quarter of 2008 was primarily a result of the higher cost of natural gas for fuel for the Company's thermal operations and increased property tax and power costs.

North America natural gas production expense for the six months ended June 30, 2008 increased 7% to $0.97 per mcf from $0.91 per mcf for the six months ended June 30, 2007. Second quarter North America natural gas production expense increased 7% to $0.93 per mcf from $0.87 per mcf for the second quarter of 2007 and decreased 8% from $1.01 per mcf for the prior quarter. The increase in production expense per mcf from the comparable periods in 2007 was a result of lower sales volumes on the fixed cost portion of production costs. The decrease from the prior period was a result of normal seasonal activity.

North Sea

North Sea crude oil production expense increased on a per bbl basis from the comparable periods in 2007 and the prior quarter due to lower production volumes on a relatively fixed cost base and the timing of liftings and maintenance activities on various fields. The Company is experiencing pressure from rising fuel costs and industry wide higher service and environmental costs.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per bbl basis from the comparable periods in 2007 and the prior quarter primarily due to the impact of the timing of liftings at the Baobab and Espoir Fields, resulting in a greater proportion of relatively higher fixed cost Baobab sales in the quarter.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2008**	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Revenue	**$ 20**	$ 20	$ 17	**$ 40**	$ 36
Production expense	**8**	5	5	**13**	11
Midstream cash flow	**12**	15	12	**27**	25
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	**$ 10**	$ 13	$ 10	**$ 23**	$ 21

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Expense ($ millions)	**$ 668**	$ 686	$ 718	**$ 1,354**	$ 1,425
$/boe (2)	**$ 12.88**	$ 12.87	$ 12.95	**$ 12.88**	$ 12.84

(1) DD&A excludes depreciation on midstream assets.

(2) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") for the six months ended June 30, 2008 and the second quarter decreased in total from the comparable periods in 2007 and the prior quarter. The decrease in DD&A expense from the prior periods was primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Expense ($ millions)	**$ 17**	$ 17	$ 17	**$ 34**	$ 35
$/boe (1)	**$ 0.33**	$ 0.31	$ 0.30	**$ 0.32**	$ 0.31

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for the six months ended June 30, 2008 and the second quarter was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2008	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Expense ($ millions)	**$ 45**	$ 43	$ 53	**$ 88**	$ 113
$/boe (1)	**$ 0.87**	$ 0.80	$ 0.96	**$ 0.83**	$ 1.02

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the six months ended June 30, 2008 and the second quarter decreased in total and on a boe basis from the comparable periods in 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program, as well as decreased office lease costs.

STOCK-BASED COMPENSATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2008**	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Expense	**$ 459**	$ -	$ 106	**$ 459**	$ 131

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $459 million ($328 million after-tax) stock-based compensation expense for the six and three months ended June 30, 2008 as a result of the increase in the Company's share price (Company's share price as at: June 30, 2008 – C$100.84; March 31, 2008 – C$70.27; December 31, 2007 – C$72.58; June 30, 2007 – C$70.78). As required by GAAP, the Company's outstanding stock options are valued each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the six months ended June 30, 2008, the Company capitalized $132 million in stock-based compensation on the Horizon Project (June 30, 2007 – $39 million). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on June 30, 2008. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the six months ended June 30, 2008, the Company paid $184 million for stock options surrendered for cash settlement (June 30, 2007 – $221 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Expense, gross	**$ 141**	$ 160	$ 158	**$ 301**	$ 312
Less: capitalized interest, Horizon Project	**110**	111	81	**221**	152
Expense, net	**$ 31**	$ 49	$ 77	**$ 80**	$ 160
$/boe (1)	**$ 0.60**	$ 0.92	$ 1.40	**$ 0.76**	$ 1.44
Average effective interest rate	**4.8%**	5.5%	5.4%	**5.2%**	5.4%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense and the Company's average effective interest rate decreased from the comparable periods in 2007 and the prior quarter primarily due to decreased short term borrowing rates in the six months ended June 30, 2008 and the impact of the strong Canadian dollar, offset by an increased proportion of higher cost US dollar denominated debt.

On commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase, increasing interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Crude oil and NGLs financial instruments	**$ 944**	$ 463	$ 100	**$ 1,407**	$ 95
Natural gas financial instruments	**10**	(47)	(8)	**(37)**	(91)
Realized loss	**$ 954**	$ 416	$ 92	**$ 1,370**	$ 4
Crude oil and NGLs financial instruments	**$ 1,380**	$ 51	$ 64	**$ 1,431**	$ 394
Natural gas financial instruments	**38**	59	(121)	**97**	85
Foreign currency swaps	**(3)**	(2)	-	**(5)**	-
Unrealized loss (gain)	**$ 1,415**	$ 108	$ (57)	**$ 1,523**	$ 479
Net loss	**$ 2,369**	$ 524	$ 35	**$ 2,893**	$ 483

The net realized loss (gain) from crude oil and natural gas financial instruments would have decreased (increased) the Company's average realized prices as follows:

	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Crude oil and NGLs ($/bbl) (1)	**$ 32.84**	$ 15.47	$ 3.41	**$ 23.98**	$ 1.61
Natural gas ($/mcf) (1)	**$ 0.07**	$ (0.33)	$ (0.05)	**$ (0.13)**	$ (0.29)

(1) Amounts expressed on a per unit basis are based on sales volumes.

Complete details related to outstanding derivative financial instruments at June 30, 2008 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at June 30, 2008. Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,523 million ($1,073 million after-tax) on its commodity risk management activities for the six months ended June 30, 2008, including a $1,415 million ($997 million after-tax) net unrealized loss for the second quarter of 2008 (March 31, 2008 – unrealized loss of $108 million, $76 million after-tax; June 30, 2007 – unrealized gain of $57 million, $35 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2008**	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Net realized (gain) loss	**$ (11)**	$ (12)	$ 26	**$ (23)**	$ 31
Net unrealized (gain) loss [1]	**(20)**	126	(250)	**106**	(282)
Net (gain) loss	**$ (31)**	$ 114	$ (224)	**$ 83**	$ (251)

(1) Amounts are reported net of the hedging effect of cross currency swaps as described in Risk Management Activities.

The Company's operating results are affected by fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely, a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar, while production expenses in Offshore West Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the Canadian dollar to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange loss for the six months ended June 30, 2008 was primarily related to the weakening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized loss for the six months ended June 30, 2008 was an unrealized gain of $58 million (six months ended June 30, 2007 – unrealized loss of $207 million) related to the impact of the cross currency swaps. The net realized foreign exchange gain for the six months ended June 30, 2008 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US dollar denominated debt. The Canadian dollar ended the second quarter at US$0.9817 compared to US$0.9729 at March 31, 2008 (December 31, 2007 – US$1.0120, June 30, 2007 – US$0.9404).

TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Current	**$ 96**	$ 70	$ 9	**$ 166**	$ 75
Deferred	**(34)**	(21)	20	**(55)**	17
Taxes other than income tax	**$ 62**	$ 49	$ 29	**$ 111**	$ 92
North America	**$ 6**	$ 21	$ 12	**$ 27**	$ 37
North Sea	**111**	96	54	**207**	89
Offshore West Africa	**34**	38	16	**72**	26
Current income tax	**151**	155	82	**306**	152
Future income tax	**(301)**	80	116	**(221)**	216
	(150)	235	198	**85**	368
Income tax rate and other legislative changes (1) (2)	**-**	41	71	**41**	71
	$ (150)	$ 276	$ 269	**$ 126**	$ 439
Effective income tax rate before non-recurring benefits	**30.2%**	28.7%	25.9%	**27.1%**	29.7%

(1) Includes the effect of a one time recovery of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions enacted or substantively enacted during the first quarter of 2008.

(2) Includes the effect of a one time recovery of $71 million due to Canadian Federal income tax rate reductions enacted during the second quarter of 2007.

Taxes other than income tax primarily includes current and deferred petroleum revenue tax ("PRT"). PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2008	Mar 31 2008	Jun 30 2007	Six Months Ended Jun 30 2008	Jun 30 2007
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 263**	$ (8)	$ 15	**$ 255**	$ 61
Land acquisition and retention	**24**	12	22	**36**	51
Seismic evaluations	**18**	27	34	**45**	84
Well drilling, completion and equipping	**286**	452	288	**738**	1,002
Production and related facilities	**270**	319	243	**589**	577
Total net reserve replacement expenditures	**861**	802	602	**1,663**	1,775
Horizon Project:					
Phase 1 construction costs	**875**	665	704	**1,540**	1,378
Phase 1 operating and capital inventory	**14**	41	-	**55**	-
Phase 1 commissioning costs	**34**	49	-	**83**	-
Phases 2/3 costs	**82**	77	19	**159**	63
Capitalized interest, stock-based compensation and other	**247**	109	118	**356**	209
Total Horizon Project	**1,252**	941	841	**2,193**	1,650
Midstream	**3**	1	-	**4**	2
Abandonments [2]	**7**	6	13	**13**	33
Head office	**4**	3	4	**7**	9
Total net capital expenditures	**$ 2,127**	$ 1,753	$ 1,460	**$ 3,880**	$ 3,469
By segment					
North America	**$ 617**	$ 663	$ 419	**$ 1,280**	$ 1,417
North Sea	**79**	45	136	**124**	274
Offshore West Africa	**164**	94	46	**258**	82
Other	**1**	-	1	**1**	2
Horizon Project	**1,252**	941	841	**2,193**	1,650
Midstream	**3**	1	-	**4**	2
Abandonments [2]	**7**	6	13	**13**	33
Head office	**4**	3	4	**7**	9
Total	**$ 2,127**	$ 1,753	$ 1,460	**$ 3,880**	$ 3,469

(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the six months ended June 30, 2008 were $3,880 million compared to $3,469 million for the six months ended June 30, 2007. Net capital expenditures for the second quarter of 2008 were $2,127 million compared to $1,460 million for the second quarter of 2007 and $1,753 million for the prior quarter. The capital expenditures primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, offset by the effects of an overall strategic reduction in the North America natural gas drilling program. Capital expenditures in the second quarter of 2008 also included the acquisition of producing properties in the Company's Northern Plains region.

For the six months ended June 30, 2008, the Company drilled a total of 475 net wells consisting of 166 natural gas wells, 266 crude oil wells, 26 stratigraphic test and service wells and 17 wells that were dry. This compared to 783 net wells drilled for the six months ended June 30, 2007. The Company achieved an overall success rate of 96% for the six months ended June 30, 2008, excluding stratigraphic test and service wells, compared to 88% for the six months ended June 30, 2007**.**

For the second quarter of 2008, the Company drilled a total of 115 net wells consisting of 5 natural gas wells, 93 crude oil wells, 11 stratigraphic test and service wells and 6 wells that were dry. This compared to 95 net wells drilled for the second quarter of 2007 and 360 net wells for the prior quarter. The Company achieved an overall success rate of 94% for the second quarter of 2008, excluding stratigraphic test and service wells, compared to 95% for the second quarter of 2007 and 97% for the prior quarter**.**

North America

North America, including the Horizon Project, accounted for approximately 90% of the total capital expenditures for the six months ended June 30, 2008 and June 30, 2007.

During the six months ended June 30, 2008, the Company targeted 175 net natural gas wells, including 22 wells in Northeast British Columbia, 48 wells in the Northern Plains region, 51 wells in Northwest Alberta, and 54 wells in the Southern Plains region. The Company also targeted 270 net crude oil wells during the same period. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 136 heavy crude oil wells, 57 Pelican Lake crude oil wells, 36 thermal crude oil wells and 4 light crude oil wells were drilled. Another 37 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant differences in relative commodity prices between crude oil and natural gas during the six months ended June 30, 2008, the Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in 2007 and 2008, natural gas drilling activities have been reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production averaged approximately 67,000 bbl/d for the second quarter of 2008 compared to 56,000 bbl/d for the second quarter of 2007 and approximately 69,000 bbl/d for the prior quarter.

The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d when complete. Drilling is complete and construction of facilities is ongoing. First steaming is scheduled for September 2008 and first production is now targeted to commence in late 2008.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 45,000 bbl/d of production growth. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the second quarter of 2008. Drilling consisted of 32 horizontal wells and 5 vertical service wells in the second quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the second quarter of 2008 compared to 34,000 bbl/d for the second quarter of 2007 and approximately 37,000 bbl/d for the prior quarter.

For the third quarter of 2008, the Company's overall drilling activity in North America is expected to be comprised of 81 natural gas wells and 256 crude oil wells, excluding stratigraphic and service wells.

Horizon Project

First production of synthetic crude oil is now currently targeted to commence in the fourth quarter of 2008. The project status as at June 30, 2008 was as follows:

- Overall construction progress is 96.5% complete;
- Mine overburden removal has moved 67.6 million bank cubic meters, which represents approximately 97% of the total required to be moved prior to start-up;
- In Mining, 4 of 5 large excavators, 16 of 23 heavy haul trucks and all support equipment are operational;
- Completed flow through Dyke Construction in Mining;
- Main Control Room turned over to Operations;
- Completed all hydrotests, blows and flushes in Gas Treating and Sulphur Recovery;
- Introduced water to the Extraction plant;
- Completed piping in Delayed Coker/Diluent Recovery Unit area;
- Completed Piping, Electrical and Insulation in Piperacks;
- Produced first steam in Co-generation Plant; and
- Completed construction of Tank 2 and began filling with distillate for start-up.

Major activities for the third quarter of 2008 include:

- Mining of first oil sands;
- Complete remainder of Ore Preparation Plant and start-up;
- Complete commissioning of Extraction and Froth Treatment and produce first bitumen crude oil;
- Complete and commission Flares and Hydrogen Plant; and
- Complete construction and start commissioning Delayed Coker/Diluent Recovery Unit and Sulphur Plant.

The Company has budgeted revised construction costs of approximately $970 million for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

North Sea

In the second quarter of 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 2.4 net wells were drilled, including 0.8 net injection wells, with an additional 0.9 net wells drilling at the end of the quarter.

At Ninian, the Company continued with its planned investment in its long-term facilities and infrastructure strategy. One water injection well was drilled during the quarter and 1 production well was being drilled at quarter end and is due for completion in the third quarter. The Company completed a planned turnaround at Ninian during the quarter with activities including tie in of a new export pipeline from the Lyell Field. At the Murchison Platform, the second of 2 production wells planned for 2008 was completed. At Columba E, the Company successfully maintained water injection rates, thereby increasing reservoir pressure with the goal of increasing production.

Offshore West Africa

During the second quarter of 2008, 0.9 net wells were drilled, with an additional 1.5 net wells drilling at the end of the quarter.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded and construction activity on the wellhead towers, subsea facilities and the floating production storage and offtake vessel ("FPSO") are progressing as planned. Drilling commenced early in the second quarter of 2008 and first crude oil is targeted for late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d net to the Company.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Jun 30 2008**		Mar 31 2008		Dec 31 2007		Jun 30 2007
Working capital deficit (1)	**$**	**3,180**	$	1,572	$	1,382	$	860
Long-term debt (2)	**$**	**11,040**	$	11,230	$	10,940	$	10,958
Share capital	**$**	**2,754**	$	2,725	$	2,674	$	2,649
Retained earnings		**10,847**		11,248		10,575		9,169
Accumulated other comprehensive income		**6**		95		72		62
Shareholders' equity	**$**	**13,607**	$	14,068	$	13,321	$	11,880
Debt to book capitalization (2) (3)		**45%**		44%		45%		48%
Debt to market capitalization (2) (4)		**17%**		23%		22%		22%
After tax return on average common shareholders' equity (5)		**14%**		24%		22%		24%
After tax return on average capital employed (2) (6)		**8%**		14%		12%		14%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

(3) Calculated as long-term debt; divided by the book value of common shareholders' equity plus long-term debt.

(4) Calculated as long-term debt; divided by the market value of common shareholders' equity plus long-term debt.

(5) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(6) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and long-term debt for the period, including $8,781 million in average capital employed related to the Horizon Project (March 31, 2008 – $7,876 million; December 31, 2007 – $7,001 million; June 30, 2007 – $5,319 million).

The Company's capital resources at June 30, 2008 consisted primarily of cash flow from operations, available credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2007 annual MD&A**.** The Company's ability to renew existing credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. The Company's current debt ratings are BBB (high) with a negative trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's. The Company does not have any direct exposure to asset-backed commercial paper.

At June 30, 2008, the Company had undrawn bank lines of credit of $2,705 million. Details related to the Company's long-term debt at June 30, 2008 are disclosed in note 3 to the Company's unaudited interim consolidated financial statements.

At June 30, 2008, the Company's working capital deficit was $3,180 million and included the current portion of the stock-based compensation liability of $755 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $2,606 million. The settlement of the stock-based compensation liability is dependent upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at June 30, 2008.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet.

Long-term debt was $11,040 million at June 30, 2008, resulting in a debt to book capitalization ratio of 45% (March 31, 2008 – 44%; December 31, 2007 – 45%; June 30, 2007 – 48%). While this ratio is at the high end of the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that it has the balance sheet strength and flexibility to complete Phase 1 of the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program currently allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of put options is in addition to the above parameters. In accordance with the policy, approximately 57% of budgeted crude oil volumes are hedged for the remainder of 2008, approximately 18% of budgeted natural gas volumes are hedged for the third quarter of 2008 and approximately 6% of estimated crude oil volumes are hedged for 2009. In addition, 50,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2008 at a strike price of US$55.00 per bbl, 50,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$80.00 per bbl, and 42,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$100.00 per bbl. Subsequent to June 30, 2008, the Company unwound 50,000 bbl/d of US$80.00 WTI put options and entered into 50,000 bbl/d of US$100.00 WTI put options for the period January to December 2009.

Commencing January 1, 2009, following the planned completion of Phase 1 of the Horizon Project, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters.

The Company has the following commodity related net financial derivatives outstanding at June 30, 2008:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jul 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Jul 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts (1)	Jul 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	50,000 bbl/d			US$80.00	WTI
	Jan 2009	–	Dec 2009	42,000 bbl/d			US$100.00	WTI

(1) Subsequent to June 30, 2008, the Company unwound 50,000 bbl/d of US$80.00 WTI put options and entered into 50,000 bbl/d of US$100.00 WTI put options for the period January to December 2009, for a net cost of US$89 million.

Natural gas								
AECO price collars	Jul 2008	–	Sep 2008	290,000 GJ/d	C$7.50	–	C$8.69	AECO

The Company's outstanding commodity financial derivatives are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Long-term debt

As at June 30, 2008, the Company had in place unsecured bank credit facilities of $6,235 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $367 million, including $300 million related to the Horizon Project, were outstanding at June 30, 2008.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

During the second quarter of 2008, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at June 30, 2008, there were 540,773,000 common shares outstanding and 25,148,000 stock options outstanding. As at August 5, 2008, the Company had 540,810,000 common shares outstanding and 25,647,000 stock options outstanding.

In February 2008, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share for 2008. The increase represents an 18% increase from 2007, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the eighth consecutive year in which the Company has paid dividends and the seventh consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to debt repayments; operating leases relating to offshore FPSOs, drilling rigs and office space; firm commitments for gathering, processing and transmission services; as well as expenditures relating to asset retirement obligations. As at June 30, 2008, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at June 30, 2008:

($ millions)	Remaining 2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 121	$ 172	$ 156	$ 130	$ 113	$ 1,097
Offshore equipment operating lease (1)	$ 76	$ 129	$ 117	$ 115	$ 93	$ 403
Offshore drilling (2) (3)	$ 189	$ 211	$ 52	$ -	$ -	$ -
Asset retirement obligations (4)	$ 20	$ 4	$ 5	$ 4	$ 4	$ 4,534
Long-term debt (5)	$ 8	$ 2,377	$ 400	$ 407	$ 357	$ 6,453
Interest expense (6)	$ 339	$ 552	$ 492	$ 470	$ 408	$ 5,363
Office lease	$ 12	$ 26	$ 29	$ 22	$ 2	$ -
Other	$ 86	$ 288	$ 182	$ 24	$ 20	$ 53

(1) Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement commenced in the second quarter of 2008, on delivery of the rig. Estimated total remaining payments of US$81 million, after joint venture recoveries, have been included in this table for the period 2008 – 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total remaining payments of US$359 million have been included in this table for the period 2008 – 2010.

(4) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(5) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,111 million of revolving bank credit facilities due to the extendable nature of the facilities.

(6) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to long-term debt. Interest on variable-rate long-term debt was estimated based upon prevailing interest rates as at June 30, 2008.

In addition to the amounts disclosed above, the Company has budgeted revised construction costs of approximately $970 million for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Critical accounting estimates and change in accounting policies

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

For the impact of new accounting standards related to capital disclosures, inventory and financial instruments, refer to note 2 of the unaudited interim consolidated financial statements as at June 30, 2008.

International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants confirmed that effective January 1, 2011, Canadian GAAP for publicly accountable entities will be replaced in full with International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. The Company is currently assessing the impact of adopting IFRS and is developing a plan to achieve convergence to IFRS by January 1, 2011.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the second quarter of 2008, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [(1)]				
Excluding financial derivatives	$ 88	$ 0.16	$ 65	$ 0.12
Including financial derivatives	$ 44 – 46	$ 0.08 – 0.09	$ 33 – 35	$ 0.06
Natural gas – AECO C$0.10/mcf [(1)]				
Excluding financial derivatives	$ 40	$ 0.07	$ 28	$ 0.05
Including financial derivatives	$ 37	$ 0.07	$ 26	$ 0.05
Volume changes				
Crude oil – 10,000 bbl/d	$ 233	$ 0.43	$ 147	$ 0.27
Natural gas – 10 mmcf/d	$ 26	$ 0.05	$ 13	$ 0.02
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 92 – 94	$ 0.17	$ 35	$ 0.06 – 0.07
Interest rate change – 1%	$ 29	$ 0.05	$ 29	$ 0.05

(1) For details of outstanding financial instruments in place, refer to note 10 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

	Three Months Ended			Six Months Ended	
($/boe) [1]	**Jun 30 2008**	Mar 31 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Sales price [2]	**$ 84.88**	$ 65.09	$ 49.70	**$ 74.86**	$ 49.50
Royalties	**13.26**	8.43	5.99	**10.82**	6.37
Production expense [3]	**11.60**	11.02	10.44	**11.31**	10.27
Netback	**60.02**	45.64	33.27	**52.73**	32.86
Midstream contribution [3]	**(0.24)**	(0.27)	(0.20)	**(0.26)**	(0.22)
Administration	**0.87**	0.80	0.96	**0.83**	1.02
Interest, net	**0.60**	0.92	1.40	**0.76**	1.44
Realized risk management loss	**18.38**	7.82	1.66	**13.03**	0.04
Realized foreign exchange (gain) loss	**(0.20)**	(0.22)	0.47	**(0.21)**	0.28
Taxes other than income tax – current	**1.84**	1.32	0.16	**1.58**	0.67
Current income tax – North America	**0.11**	0.40	0.21	**0.26**	0.33
Current income tax – North Sea	**2.15**	1.79	0.99	**1.97**	0.81
Current income tax – Offshore West Africa	**0.65**	0.71	0.29	**0.68**	0.23
Cash flow	**$ 35.86**	$ 32.37	$ 27.33	**$ 34.09**	$ 28.26

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	Jun 30 2008	Dec 31 2007
ASSETS		
Current assets		
Cash and cash equivalents	**$ 22**	$ 21
Accounts receivable and other	**2,340**	1,662
Future income tax	**992**	480
Current portion of other long-term assets	**-**	18
	3,354	2,181
Property, plant and equipment (note 12)	**36,482**	33,902
Other long-term assets	**31**	31
	$ 39,867	$ 36,114
LIABILITIES		
Current liabilities		
Accounts payable	**$ 489**	$ 379
Accrued liabilities	**2,634**	1,567
Current portion of other long-term liabilities (note 4)	**3,411**	1,617
	6,534	3,563
Long-term debt (note 3)	**11,040**	10,940
Other long-term liabilities (note 4)	**1,722**	1,561
Future income tax	**6,964**	6,729
	26,260	22,793
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**2,754**	2,674
Retained earnings	**10,847**	10,575
Accumulated other comprehensive income (note 7)	**6**	72
	13,607	13,321
	$ 39,867	$ 36,114

Commitments (note 11)

Consolidated Statements of Earnings (Loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Jun 30 2008	Three Months Ended Jun 30 2007	Six Months Ended Jun 30 2008	Six Months Ended Jun 30 2007
Revenue	**$ 5,112**	$ 3,152	**$ 9,079**	$ 6,270
Less: royalties	**(688)**	(331)	**(1,137)**	(707)
Revenue, net of royalties	**4,424**	2,821	**7,942**	5,563
Expenses				
Production	**610**	584	**1,197**	1,149
Transportation and blending	**689**	385	**1,174**	744
Depletion, depreciation and amortization	**670**	720	**1,358**	1,429
Asset retirement obligation accretion (note 4)	**17**	17	**34**	35
Administration	**45**	53	**88**	113
Stock-based compensation (note 4)	**459**	106	**459**	131
Interest, net	**31**	77	**80**	160
Risk management activities (note 10)	**2,369**	35	**2,893**	483
Foreign exchange (gain) loss	**(31)**	(224)	**83**	(251)
	4,859	1,753	**7,366**	3,993
Earnings (loss) before taxes	**(435)**	1,068	**576**	1,570
Taxes other than income tax	**62**	29	**111**	92
Current income tax expense (note 5)	**151**	82	**306**	152
Future income tax (recovery) expense (note 5)	**(301)**	116	**(221)**	216
Net earnings (loss)	**$ (347)**	$ 841	**$ 380**	$ 1,110
Net earnings (loss) per common share (note 9)				
Basic and diluted	**$ (0.65)**	$ 1.56	**$ 0.70**	$ 2.06

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Six Months Ended **Jun 30 2008**	Jun 30 2007
Share capital (note 6)		
Balance – beginning of period	**$ 2,674**	$ 2,562
Issued upon exercise of stock options	**14**	16
Previously recognized liability on stock options exercised for common shares	**66**	71
Balance – end of period	**2,754**	2,649
Retained earnings		
Balance – beginning of period	**10,575**	8,151
Net earnings	**380**	1,110
Dividends on common shares (note 6)	**(108)**	(92)
Balance – end of period	**10,847**	9,169
Accumulated other comprehensive income (note 7)		
Balance – beginning of period	**72**	146
Other comprehensive loss, net of taxes	**(66)**	(84)
Balance – end of period	**6**	62
Shareholders' equity	**$ 13,607**	$ 11,880

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2008**	Jun 30 2007	Six Months Ended **Jun 30 2008**	Jun 30 2007
Net earnings (loss)	**$ (347)**	$ 841	**$ 380**	$ 1,110
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $13 million (2007 - $47 million) – three months ended; $15 million (2007 - $8 million) – six months ended	**(89)**	112	**(65)**	(4)
Reclassification to net earnings (loss), net of taxes of $1 million (2007 - $nil) – three months ended; $7 million (2007 - $35 million) – six months ended	**3**	(1)	**(14)**	(75)
	(86)	111	**(79)**	(79)
Foreign currency translation adjustment				
Translation of net investment	**(3)**	(4)	**13**	(5)
Other comprehensive income (loss), net of taxes	**(89)**	107	**(66)**	(84)
Comprehensive income (loss)	**$ (436)**	$ 948	**$ 314**	$ 1,026

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2008**	Three Months Ended Jun 30 2007	Six Months Ended **Jun 30 2008**	Six Months Ended Jun 30 2007
Operating activities				
Net earnings (loss)	**$ (347)**	$ 841	**$ 380**	$ 1,110
Non-cash items				
Depletion, depreciation and amortization	**670**	720	**1,358**	1,429
Asset retirement obligation accretion	**17**	17	**34**	35
Stock-based compensation	**459**	106	**459**	131
Unrealized risk management loss (gain)	**1,415**	(57)	**1,523**	479
Unrealized foreign exchange (gain) loss	**(20)**	(250)	**106**	(282)
Deferred petroleum revenue tax (recovery) expense	**(34)**	20	**(55)**	17
Future income tax (recovery) expense	**(301)**	116	**(221)**	216
Other	**6**	8	**19**	(5)
Abandonment expenditures	**(7)**	(13)	**(13)**	(33)
Net change in non-cash working capital	**314**	131	**148**	12
	2,172	1,639	**3,738**	3,109
Financing activities				
(Repayment) issue of bank credit facilities, net	**(68)**	167	**(1,240)**	(1,846)
Repayment of medium-term notes	**-**	-	**-**	(125)
Repayment of senior unsecured notes	**(31)**	(33)	**(31)**	(33)
Issue of US dollar debt securities	**-**	-	**1,223**	2,553
Issue of common shares on exercise of stock options	**5**	3	**14**	16
Dividends on common shares	**(54)**	(46)	**(100)**	(86)
Net change in non-cash working capital	**25**	45	**30**	23
	(123)	136	**(104)**	502
Investing activities				
Expenditures on property, plant and equipment	**(2,121)**	(1,447)	**(3,877)**	(3,440)
Net proceeds on sale of property, plant and equipment	**1**	-	**10**	4
Net expenditures on property, plant and equipment	**(2,120)**	(1,447)	**(3,867)**	(3,436)
Net change in non-cash working capital	**66**	(331)	**234**	(187)
	(2,054)	(1,778)	**(3,633)**	(3,623)
(Decrease) increase in cash and cash equivalents	**(5)**	(3)	**1**	(12)
Cash and cash equivalents – beginning of period	**27**	14	**21**	23
Cash and cash equivalents – end of period	**$ 22**	$ 11	**$ 22**	$ 11
Interest paid	**$ 132**	$ 87	**$ 278**	$ 245
Taxes paid (recovered)				
Taxes other than income tax	**$ 24**	$ 39	**$ 55**	$ 74
Current income tax	**$ (108)**	$ 1	**$ (55)**	$ 72

Notes to the consolidated financial statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2007, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2007.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008 the Company adopted the following accounting and disclosure standards issued by the Canadian Institute of Chartered Accountants:

- **Capital Disclosures** – Section 1535 – "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affects disclosure only and did not impact the Company's accounting for capital (note 8).
- **Inventories** – Section 3031 – "Inventories" replaces Section 3030 – "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.
- **Financial Instruments** – Section 3862 – "Financial Instruments – Disclosure" and Section 3863 – "Financial Instruments – Presentation" replace Section 3861 – "Financial Instruments – Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affect disclosures only and do not impact the Company's accounting for financial instruments (note 10).

3. LONG–TERM DEBT

	Jun 30 2008	Dec 31 2007
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 3,456**	$ 4,696
Medium-term notes	**1,200**	1,200
	4,656	5,896
US dollar denominated debt		
Senior unsecured notes (2008 - US$31 million; 2007 - US$62 million)	**32**	61
US dollar debt securities (2008 - US$6,308 million; 2007 - US$5,108 million)	**6,425**	5,048
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(24)**	(23)
	6,433	5,086
Fair value of interest rate swaps on US dollar debt securities (2)	**9**	9
	6,442	5,095
Long-term debt before transaction costs	**11,098**	10,991
Less – transaction costs (1) (3)	**(58)**	(51)
	$ 11,040	$ 10,940

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $9 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank credit facilities

As at June 30, 2008, the Company had in place unsecured bank credit facilities of $6,235 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

The weighted average interest rate of the bank credit facilities outstanding at June 30, 2008, was 3.6% (December 31, 2007 – 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $367 million, including $300 million related to the Horizon Oil Sands Project ("Horizon Project"), were outstanding at June 30, 2008.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

During the second quarter of 2008, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

4. OTHER LONG–TERM LIABILITIES

	Jun 30 2008	Dec 31 2007
Asset retirement obligations	**$ 1,120**	$ 1,074
Stock-based compensation	**870**	529
Risk management (note 10)	**3,042**	1,474
Other	**101**	101
	5,133	3,178
Less: current portion	**3,411**	1,617
	$ 1,722	$ 1,561

Asset retirement obligations

At June 30, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,571 million (December 31, 2007 – $4,426 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk free rate of 6.6% (December 31, 2007 – 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Six Months Ended Jun 30, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	**$ 1,074**	$ 1,166
Liabilities incurred	**10**	21
Liabilities acquired (disposed)	**2**	(65)
Liabilities settled	**(13)**	(71)
Asset retirement obligation accretion	**34**	70
Revision of estimates	**-**	35
Foreign exchange	**13**	(82)
Balance – end of period	**$ 1,120**	$ 1,074

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested options are surrendered for cash settlement.

	Six Months Ended Jun 30, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	**$ 529**	$ 744
Stock-based compensation	**459**	193
Payments for options surrendered	**(184)**	(375)
Transferred to common shares	**(66)**	(91)
Capitalized to Horizon Project	**132**	58
Balance – end of period	**870**	529
Less: current portion	**755**	390
	$ 115	$ 139

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Current income tax – North America	**$ 6**	$ 12	**$ 27**	$ 37
Current income tax – North Sea	**111**	54	**207**	89
Current income tax – Offshore West Africa	**34**	16	**72**	26
Current income tax expense	**151**	82	**306**	152
Future income tax (recovery) expense	**(301)**	116	**(221)**	216
Income tax (recovery) expense	**$ (150)**	$ 198	**$ 85**	$ 368

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

During the first quarter of 2008, enacted or substantively enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and $22 million in Côte d'Ivoire, Offshore West Africa.

During the second quarter of 2007, the Canadian Federal Government enacted income tax rate changes, resulting in a reduction of future income tax liabilities of approximately $71 million.

6. SHARE CAPITAL

Issued Common shares	Six Months Ended Jun 30, 2008 Number of shares (thousands)	Amount
Balance – beginning of period	**539,729**	**$ 2,674**
Issued upon exercise of stock options	**1,044**	**14**
Previously recognized liability on stock options exercised for common shares	**-**	**66**
Balance – end of period	**540,773**	**$ 2,754**

Dividend policy

In February 2008, the Board of Directors set the regular quarterly dividend at $0.10 per common share. The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Stock options

	Six Months Ended Jun 30, 2008 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**30,659**	**$ 47.23**
Granted	**346**	**$ 72.14**
Surrendered for cash settlement	**(3,253)**	**$ 25.42**
Exercised for common shares	**(1,044)**	**$ 14.00**
Forfeited	**(1,560)**	**$ 54.74**
Outstanding – end of period	**25,148**	**$ 51.30**
Exercisable – end of period	**6,572**	**$ 36.91**

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	Jun 30 2008	Jun 30 2007
Derivative financial instruments designated as cash flow hedges	**$ 22**	$ 80
Foreign currency translation adjustment	**(16)**	(18)
	$ 6	$ 62

8. CAPITAL DISCLOSURES

As required by Canadian generally accepted accounting principles ("GAAP"), effective January 1, 2008, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed capital requirements, for the purposes of this disclosure, the Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of long-term debt divided by the sum of the carrying value of shareholders' equity plus long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently at the high end of the target range due to the debt financing of a business acquisition in 2006 and the construction of the Horizon Project.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure at some point in the future.

	Jun 30 2008	Dec 31 2007
Long-term debt	**$ 11,040**	$ 10,940
Total shareholders' equity	**$ 13,607**	$ 13,321
Debt to book capitalization	**45%**	45%

9. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Weighted average common shares outstanding (thousands) – basic and diluted	**540,632**	539,296	**540,425**	539,094
Net earnings (loss) – basic and diluted	**$ (347)**	$ 841	**$ 380**	$ 1,110
Net earnings (loss) per common share – basic and diluted	**$ (0.65)**	$ 1.56	**$ 0.70**	$ 2.06

10. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	Jun 30, 2008		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ -**	**$ 22**	**$ -**
Accounts receivable	**1,786**	**-**	**-**
Accounts payable	**-**	**-**	**(489)**
Accrued liabilities	**-**	**-**	**(2,634)**
Risk management	**-**	**(3,042)**	**-**
Long-term debt	**-**	**-**	**(11,040)**
	$ 1,786	**$ (3,020)**	**$ (14,163)**

	Dec 31, 2007		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 21	$ -
Accounts receivable	1,143	-	-
Accounts payable	-	-	(379)
Accrued liabilities	-	-	(1,567)
Risk management	-	(1,474)	-
Long-term debt	-	-	(10,940)
	$ 1,143	$ (1,453)	$ (12,886)

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below:

	Jun 30, 2008		Dec 31, 2007	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed-rate long-term debt (1)	**$ 7,584**	**$ 7,535**	$ 6,244	$ 6,259

(1) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $9 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

Risk management

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not intended for trading or other speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

	Six Months Ended Jun 30, 2008	Year Ended Dec 31, 2007
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (1,474)**	$ 128
Retained earnings effect of adoption of financial instrument standards	**-**	14
Net cost of outstanding put options	**186**	58
Net change in fair value of outstanding derivative financial instruments attributable to:		
- Risk management activities	**(1,523)**	(1,400)
- Interest expense	**(1)**	9
- Foreign exchange	**58**	(350)
- Other comprehensive income	**(102)**	125
	(2,856)	(1,416)
Add: Put premium financing obligations (1)	**(186)**	(58)
Balance – end of period	**(3,042)**	(1,474)
Less: current portion	**(2,606)**	(1,227)
	$ (436)	$ (247)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net losses (gains) from risk management activities were as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2008	Jun 30 2007	**Jun 30 2008**	Jun 30 2007
Net realized risk management loss	**$ 954**	$ 92	**$ 1,370**	$ 4
Net unrealized risk management loss (gain)	**1,415**	(57)	**1,523**	479
	$ 2,369	$ 35	**$ 2,893**	$ 483

Financial risk factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk

The Company uses commodity price financial derivatives to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. At June 30, 2008, the Company had the following net financial derivatives outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jul 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Jul 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jul 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts [(1)]	Jul 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	50,000 bbl/d			US$80.00	WTI
	Jan 2009	–	Dec 2009	42,000 bbl/d			US$100.00	WTI

(1) Subsequent to June 30, 2008, the Company unwound 50,000 bbl/d of US$80.00 WTI put options and entered into 50,000 bbl/d of US$100.00 WTI put options for the period January to December 2009, for a net cost of US$89 million.

At June 30, 2008, the net cost of outstanding put options and their respective periods of settlement was as follows:

	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Cost ($ millions)	US$15	US$15	US$38	US$38	US$38	US$38

	Remaining term			Volume	Weighted average price			Index
Natural gas								
AECO price collars	Jul 2008	–	Sep 2008	290,000 GJ/d	C$7.50	–	C$8.69	AECO

The Company's outstanding commodity financial derivatives are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Interest rate risk

The Company is exposed to interest rate risk on its fixed and floating rate long-term debt. The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At June 30, 2008, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jul 2008 – Oct 2012	US$350	5.45%	LIBOR [1] + 0.81%
	Jul 2008 – Dec 2014	US$350	4.90%	LIBOR [1] + 0.38%

(1) London Interbank Offered Rate

All interest rate related derivative financial instruments designated as hedges at June 30, 2008 were classified as fair value hedges.

Foreign currency exchange rate risk

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated debt. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company enters into cross currency swap agreements to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At June 30, 2008, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jul 2008 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2008 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2008 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency related derivative financial instruments designated as hedges at June 30, 2008 were classified as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at June 30, 2008 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (34)	$ -
Decrease WTI US$1.00/bbl	$ 34	$ -
Increase AECO C$0.10/mcf	$ (2)	$ -
Decrease AECO C$0.10/mcf	$ 2	$ -
Interest rate risk		
Increase interest rate 1%	$ (21)	$ 26
Decrease interest rate 1%	$ 21	$ (32)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (33)	$ -
Decrease exchange rate by US$0.01	$ 33	$ -

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss for the Company by failing to discharge an obligation.

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. At June 30, 2008, the Company had net risk management assets of $3 million with specific counterparties related to derivative financial instruments (December 31, 2007 – $20 million).

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company maintains adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	489	$	-	$	-	$	-
Accrued liabilities	$	2,634	$	-	$	-	$	-
Risk management	$	2,606	$	182	$	(35)	$	289
Long-term debt (1)	$	40	$	2,345	$	1,971	$	5,646

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,111 million of revolving bank credit facilities due to the extendable nature of the facilities.

11. COMMITMENTS

As at June 30, 2008, the Company had committed to certain payments as follows:

		Remaining 2008		2009		2010		2011		2012		Thereafter
Product transportation and pipeline	$	121	$	172	$	156	$	130	$	113	$	1,097
Offshore equipment operating leases (1)	$	76	$	129	$	117	$	115	$	93	$	403
Offshore drilling (2) (3)	$	189	$	211	$	52	$	-	$	-	$	-
Asset retirement obligations (4)	$	20	$	4	$	5	$	4	$	4	$	4,534
Office leases	$	12	$	26	$	29	$	22	$	2	$	-
Other	$	86	$	288	$	182	$	24	$	20	$	53

(1) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement commenced in the second quarter of 2008, on delivery of the rig. Estimated total remaining payments of US$81 million, after joint venture recoveries, have been included in this table for the period 2008 – 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total remaining payments of US$359 million have been included in this table for the period 2008 – 2010.

(4) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In addition to the amounts disclosed above, the Company has budgeted revised construction costs of approximately $970 million for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**4,282**	2,584	**7,497**	5,119	**537**	402	**1,045**	833	**287**	161	**524**	305
Less: royalties	**(651)**	(315)	**(1,056)**	(681)	**(1)**	-	**(2)**	(1)	**(36)**	(16)	**(79)**	(25)
Segmented revenue, net of royalties	**3,631**	2,269	**6,441**	4,438	**536**	402	**1,043**	832	**251**	145	**445**	280
Segmented expenses												
Production	**475**	442	**926**	864	**105**	120	**217**	236	**25**	18	**46**	40
Transportation and blending	**698**	391	**1,191**	756	**2**	4	**5**	8	**-**	-	**-**	-
Depletion, depreciation and amortization	**562**	595	**1,128**	1,155	**72**	87	**158**	194	**34**	36	**68**	76
Asset retirement obligation accretion	**9**	10	**20**	19	**7**	7	**13**	15	**1**	-	**1**	1
Realized risk management loss (gain)	**954**	67	**1,371**	(25)	**-**	25	**(1)**	29	**-**	-	**-**	-
Total segmented expenses	**2,698**	1,505	**4,636**	2,769	**186**	243	**392**	482	**60**	54	**115**	117
Segmented earnings before the following	**933**	764	**1,805**	1,669	**350**	159	**651**	350	**191**	91	**330**	163
Non-segmented expenses												
Administration												
Stock-based compensation expense												
Interest, net												
Unrealized risk management loss (gain)												
Foreign exchange (gain) loss												
Total non-segmented expenses												
Earnings (loss) before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax (recovery) expense												
Net earnings (loss)												

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Jun 30		Midstream Six Months Ended Jun 30		Inter-segment elimination and other Three Months Ended Jun 30		Inter-segment elimination and other Six Months Ended Jun 30		Total Three Months Ended Jun 30		Total Six Months Ended Jun 30	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**20**	17	**40**	36	**(14)**	(12)	**(27)**	(23)	**5,112**	3,152	**9,079**	6,270
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(688)**	(331)	**(1,137)**	(707)
Segmented revenue, net of royalties	**20**	17	**40**	36	**(14)**	(12)	**(27)**	(23)	**4,424**	2,821	**7,942**	5,563
Segmented expenses												
Production	**8**	5	**13**	11	**(3)**	(1)	**(5)**	(2)	**610**	584	**1,197**	1,149
Transportation and blending	**-**	-	**-**	-	**(11)**	(10)	**(22)**	(20)	**689**	385	**1,174**	744
Depletion, depreciation and amortization	**2**	2	**4**	4	**-**	-	**-**	-	**670**	720	**1,358**	1,429
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**17**	17	**34**	35
Realized risk management loss (gain)	**-**	-	**-**	-	**-**	-	**-**	-	**954**	92	**1,370**	4
Total segmented expenses	**10**	7	**17**	15	**(14)**	(11)	**(27)**	(22)	**2,940**	1,798	**5,133**	3,361
Segmented earnings before the following	**10**	10	**23**	21	**-**	(1)	**-**	(1)	**1,484**	1,023	**2,809**	2,202
Non-segmented expenses												
Administration									**45**	53	**88**	113
Stock-based compensation expense									**459**	106	**459**	131
Interest, net									**31**	77	**80**	160
Unrealized risk management loss (gain)									**1,415**	(57)	**1,523**	479
Foreign exchange (gain) loss									**(31)**	(224)	**83**	(251)
Total non-segmented expenses									**1,919**	(45)	**2,233**	632
Earnings (loss) before taxes									**(435)**	1,068	**576**	1,570
Taxes other than income tax									**62**	29	**111**	92
Current income tax expense									**151**	82	**306**	152
Future income tax (recovery) expense									**(301)**	116	**(221)**	216
Net earnings (loss)									**(347)**	841	**380**	1,110

Net additions to property, plant and equipment

	Six Months Ended					
	Jun 30, 2008			Jun 30, 2007		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,280**	**$ 12**	**$ 1,292**	$ 1,417	$ 8	$ 1,425
North Sea	**124**	**-**	**124**	274	-	274
Offshore West Africa	**258**	**(2)**	**256**	82	-	82
Other	**1**	**-**	**1**	2	-	2
Horizon Project (2)	**2,193**	**-**	**2,193**	1,650	-	1,650
Midstream	**4**	**-**	**4**	2	-	2
Head office	**7**	**-**	**7**	9	-	9
	$ 3,867	**$ 10**	**$ 3,877**	$ 3,436	$ 8	$ 3,444

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Jun 30 2008	Dec 31 2007	**Jun 30 2008**	Dec 31 2007
Segmented assets				
North America	**$ 22,205**	$ 22,033	**$ 24,922**	$ 23,617
North Sea	**1,761**	1,728	**2,121**	1,957
Offshore West Africa	**1,373**	1,188	**1,445**	1,354
Other	**26**	25	**38**	41
Horizon Project	**10,844**	8,651	**10,943**	8,740
Midstream	**205**	205	**330**	333
Head office	**68**	72	**68**	72
	$ 36,482	$ 33,902	**$ 39,867**	$ 36,114

Capitalized interest

The Company capitalizes construction period interest based on Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the six months ended June 30, 2008, pre-tax interest of $221 million was capitalized to the Horizon Project (June 30, 2007 – $152 million).

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated September 2007. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended June 30, 2008:

Interest coverage (times)	
Net earnings (1)	2.8x
Cash flow from operations (2)	11.9x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

CONFERENCE CALL

A conference call will be held at 7:00 a.m. Mountain Time, 9:00 a.m. Eastern Time on Thursday, August 7, 2008. The North American conference call number is **1-877-461-2816** and the outside North American conference call number is **001-416-695-9761**. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday August 14, 2008. To access the postview in North America, dial **1-800-408-3053.** Those outside of North America, dial **001-416-695-5800.** The passcode to use is 3262068.

WEBCAST

This call is being webcast by Vcall and can be accessed on Canadian Natural's website at www.cnrl.com/investor_info/calendar.html.

The webcast is also being distributed over PrecisionIR's Investor Distribution Network to both institutional and individual investors. Investors can listen to the call through www.vcall.com or by visiting any of the investor sites in PrecisionIR's Individual Investor Network.

2008 THIRD QUARTER RESULTS

2008 third quarter results are scheduled for release prior to market opening on Thursday, November 6, 2008. A conference call will be held on that day at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

For further information, please contact:

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