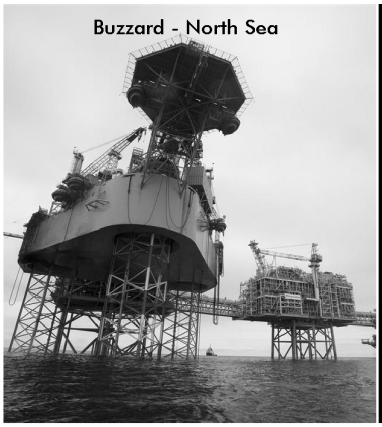

nexen

Q3 INTERIM REPORT

For three months ended September 30, 2008

Nexen's Third Quarter Results: Record Cash Flow

(Cdn$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Production before Royalties (mboe/d)[1]	249	261	257	251
Production after Royalties (mboe/d)[1]	209	214	214	204
Net Sales	2,213	1,446	6,154	3,985
Cash Flow from Operations[2]	1,685	868	3,670	2,379
Per Common Share ($/share)	3.20	1.65	6.95	4.52
Net Income	886	403	1,896	892
Per Common Share ($/share)	1.68	0.77	3.59	1.69
Capital Expenditures, including Acquisitions[3]	725	901	2,149	2,531
Net Debt[4]	3,914	4,393	3,914	4,393
Common Shares Outstanding (millions of shares)	521.0	527.4	521.0	527.4

1 Includes our share of Syncrude oil sands.
2 Cash flow from operations is defined as cash flow from operating activities before changes in non-cash working capital and other.
3 Includes oil and gas development, exploration, and expenditures for other property, plant and equipment.
4 Defined as long-term debt and short-term borrowings less cash and cash equivalents.

Nexen delivered excellent third quarter results including record cash flow of $1.7 billion. With no hedges in place and over 85% of our production weighted to crude oil, we were able to realize significant benefits from high oil prices. For the first nine months of the year, we have generated almost $3.7 billion of cash flow and this has exceeded our capital investment by over $1.5 billion. We have used some of this surplus to buyback shares. With the tightening credit markets, we realize cash is a valuable asset. We are slowing our capital expenditures and building our cash reserves during this time. For the full year, we expect our cash flow to be around $4.4 billion based on today's commodity prices and foreign exchange rates. Net income was $886 million for the quarter and includes a recovery of $408 million ($241 million after tax) for stock-based compensation as our share price dropped since the end of the second quarter. Our results also reflect additional one-time tax deductions in the UK following the completion of an internal reorganization and financing of our assets in the North Sea. This combined with falling commodity prices lowered our tax accrual and increased our quarterly cash flow. Marketing reported a cash flow loss of $65 million in the quarter, reflecting continued but reduced losses from our natural gas business offset in part by gains from crude oil marketing. For the past few months, we have been simplifying our marketing strategies to better support our underlying physical business which has been built around storage, blending and transportation.

Quarterly production averaged 249,000 boe/d before royalties. Buzzard continues to perform well and contributed 89,600 boe/d (207,500 boe/d gross). Gulf of Mexico (GOM) production was negatively impacted by hurricanes Gustav and Ike. We are currently producing 6,500 boe/d here compared to 30,000 boe/d prior to the storms. For the fourth quarter, we expect our GOM production to average 10,000 to 20,000 boe/d. Volumes will depend on the timing of repair work and the readiness of third-party infrastructure. We carry insurance coverage for physical damage caused by hurricanes, subject to deductibles.

At Long Lake, we are pleased to be close to first production of synthetic crude. Commissioning of the gasifier was delayed about three weeks due to mechanical issues with valves. Bitumen production is ramping up and the reservoir continues to perform well. We have converted 45 of 81 well pairs and gross production recently exceeded 19,000 bbls/d. We expect to reach design rates of 72,000 bbls/d (36,000 bbls/d net), upgraded to about 60,000 bbls/d late next year or early 2010.

On the exploration front, we had success in the UK North Sea. At Pink, we drilled successful exploration and sidetrack wells and see further opportunities in the area. Pink is a candidate for co-development with Golden Eagle. We also made a discovery at Blackbird. Further appraisal is planned with a view of tieing back Blackbird to our nearby Ettrick development.

The Board of Directors declared a quarterly dividend of $0.05 per common share payable January 1, 2009, to shareholders of record on October 10, 2008.

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A)

The following should be read in conjunction with the Unaudited Consolidated Financial Statements included in this report. The Unaudited Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of the significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 20 to the Unaudited Consolidated Financial Statements. The date of this discussion is October 28, 2008.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. The discussion and analysis of our oil and gas activities with respect to oil and gas volumes, reserves and related performance measures is presented on a working-interest, before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on a net, after-royalties basis in tabular format.

Note: Canadian investors should read the Special Note to Canadian Investors on page 76 of our 2007 10-K which highlights differences between our reserves estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Unaudited Consolidated Financial Statements and our revenues and expenses during the reported period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, fair values of derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

EXECUTIVE SUMMARY OF THIRD QUARTER RESULTS

	Three Months Ended September 30		Nine Months Ended September 30	
(Cdn$ millions)	**2008**	**2007**	**2008**	**2007**
Net Income	886	403	1,896	892
Earnings per Common Share, Basic ($/share)	1.68	0.77	3.59	1.69
Cash Flow from Operating Activities	968	1,097	3,299	2,127
Production before Royalties (mboe/d)	249	261	257	251
Production after Royalties (mboe/d)	209	214	214	204
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	106.22	69.82	99.64	65.96
Capital Investment	725	901	2,149	2,531
Net Debt [1]	3,914	4,393	3,914	4,393

Note:
[1] Net debt is a non-GAAP measure and is defined as long-term debt and short–term borrowings less cash and cash equivalents.

We recognized solid net income and cash flow from operating activities during the quarter as a result of high commodity prices and strong production rates from our oil and gas operations. WTI was 57% higher than the third quarter of 2007, which allowed us to realize crude oil prices of $115.56/bbl for our sales. Production from the North Sea remains strong and uptime rates on our Buzzard platform exceeded 96% during the quarter. Our Gulf of Mexico assets were impacted by Hurricanes Ike and Gustav in September and the majority of our production is still shut in as a result of damage to platforms and third-party infrastructure and pipelines. We expect to restore the majority of this production by year end.

At Long Lake, the commissioning of the gasifier was delayed by about three weeks. Once the gasifier achieves steady state operations, the hydrocracker and sulphur units will be started and we expect first synthetic production to commence shortly thereafter. Our bitumen production rates are increasing and 45 of the total 81 well pairs have now been converted to SAGD operation. Gross production rates have recently exceeded 19,000 barrels per day.

In the quarter, our net income includes a recovery of $408 million for stock-based compensation costs that were previously expensed. Our marketing division reported a loss in the third quarter, reflecting continued, but reduced losses from our natural gas marketing business which were partially offset by strong contributions from our crude oil marketing. During the quarter, we recognized some gains on the use of physical storage and transportation assets and we have unrecognized gains, that we expect to realize on the future use of these assets, that more than offset the quarterly loss reported. Over the past few months, we have been simplifying our marketing strategies and positions to better support our underlying physical business which has been built around storage, blending and transportation. To this end, we are reducing our trading levels to reduce volatility and focus on the physical side of our business. We are exiting trading positions that do not support our physical business and we

are continuing to reduce trading exposures. This is reflected in the quarterly financial results from this division. Compared to the same time last year, our North American natural gas and crude oil financial trading volumes are down by approximately 43% and 40%, respectively.

During the third quarter, we completed an internal reorganization and financing of our assets in the North Sea which provided us with an additional one-time tax deduction in the UK. This, together with falling commodity prices, will cause our expected 2008 tax liability to be lower than previously expected. As a result, we have reduced our current tax expense by approximately $514 million. Following this reorganization and financing, we are well positioned to move forward with our development and exploration plans in the North Sea. In the short-term, these plans include the upcoming commissioning and start-up of Ettrick and our investment in the previously announced fourth platform at Buzzard to process hydrogen sulphide. Longer term, our plans include the future development of our recent discoveries at Golden Eagle, Blackbird and Pink and an active exploration program over the next few years.

Our cash flow from operating activities exceeded capital investment during the quarter by $243 million. Our net debt is $490 million lower than year-end 2007 as a result of our strong financial results. Our cash and cash equivalents on hand at September 30, 2008 was almost $1.8 billion which, together with our undrawn term credit facilities, provides us with strong liquidity to carry out our investment programs.

CAPITAL INVESTMENT

Our strategy and capital programs are focused on growing long-term value for our shareholders responsibly. We are advancing our strategy as described below. In 2008, we are investing primarily in:

- bringing Phase 1 of our Long Lake project on stream and advancing other phases;
- completing our Ettrick development in the UK North Sea;
- targeting a number of exploration prospects, primarily in the North Sea and Gulf of Mexico; and
- advancing our position in the Horn River shale gas resource play in northeastern British Columbia.

Details of our capital programs are set out below:

Three Months Ended September 30, 2008

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	194	15	–	–	209
United Kingdom	90	–	43	99	232
Yemen	–	–	–	29	29
United States	33	–	38	13	84
Canada	15	2	34	19	70
Nigeria	34	–	–	–	34
Other Countries	–	–	11	1	12
Syncrude	–	–	–	19	19
	366	17	126	180	689
Chemicals, Marketing, Corporate and Other	–	–	–	36	36
Total Capital	366	17	126	216	725
As a % of Total Capital	50%	3%	17%	30%	100%

Nine Months Ended September 30, 2008

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	623	127	2	-	752
United Kingdom	209	–	114	201	524
Yemen	–	–	9	61	70
United States	40	–	147	140	327
Canada	34	10	144	63	251
Nigeria	63	–	1	–	64
Other Countries	–	–	29	10	39
Syncrude	–	–	–	39	39
	969	137	446	514	2,066
Chemicals, Marketing, Corporate and Other	–	–	–	83	83
Total Capital	969	137	446	597	2,149
As a % of Total Capital	45%	6%	21%	28%	100%

Synthetic

Commissioning of the gasifier was delayed by about three weeks. Upon initial test firing, mechanical issues were identified with several automated valves and the burners required change-out. The burner change-out work has been completed and the automated valves have been repaired. The valves have been reinstalled and the gasifier is in the process of being refired. Once the gasifier achieves steady state operations, the hydrocracker and sulphur units will be started and we expect first synthetic production to commence shortly thereafter.

On the bitumen front, the reservoir is performing well, the reliability of our surface facilities is improving, steam injection rates are at their highest levels since SAGD start-up and production rates are increasing. In the field, 45 of the total 81 well pairs have now been converted to SAGD operation, gross production rates averaged 15,200 bbls/d for the first half of October and recently exceeded 19,000 bbls/d. The average steam to oil ratio (SOR) for the wells that have been converted to SAGD operation is currently about 4.0. About one-quarter of these wells are already at or below our long-term SOR expectation of 3.0 and approximately 10% have achieved targeted bitumen production rates. We expect to reach full design rates of 72,000 bbls/d of bitumen production (36,000 bbls/d net to us), upgraded to approximately 60,000 bbls/d of Premium Sweet Crude (PSC™) late next year or early 2010.

We are engaged in engineering and planning for Phase 2 and have received regulatory approval for the Phase 2 upgrader. Ultimately, the sanctioning of Phase 2 will depend on multiple factors including the initial performance of Phase 1, receiving regulatory approval for Phase 2 SAGD operations, receiving clarity on proposed climate change regulations, finalizing cost estimates and an improved economic environment.

United Kingdom – North Sea

In the North Sea, we drilled a discovery at Pink that encountered oil shows. These results are encouraging and consistent with pre-drill estimates. We see additional prospects in the area and are currently assessing them. Pink is a candidate for co-development with Golden Eagle where we are currently reviewing development options. We have a 34% operated interest in Golden Eagle and a 46% operated working interest in Pink.

During the quarter, we also made a discovery at Blackbird which is located six kilometres south of our operated Ettrick field. The well was drill-stem tested and flowed at an average restricted rate of 3,800 bbls/d. Further appraisal is planned with a view to tying Blackbird back to Ettrick. We operate both Ettrick and Blackbird and have an 80% working interest in each.

Delivery of the FPSO we are leasing for Ettrick has been delayed until December following commissioning delays in Singapore. The cost of these delays is borne by the owner of the FPSO. First production is now scheduled for early 2009. Production volumes are expected to average between approximately 15,000 and 20,000 boe/d in 2009. The FPSO is designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas and has capacity for nearby discoveries such as Blackbird.

United States – Gulf of Mexico

At our Cote de Mer prospect, located on the Louisiana coast, exploration drilling was interrupted by hurricanes Gustav and Ike. Upon resuming drilling operations, we experienced drilling difficulties. We have encountered the target reservoir but have not yet reached the target depth of 21,900 feet. We are encouraged by the preliminary data obtained and are currently conducting pipe recovery operations in order to resume drilling to reach target depth. We have a 37.5% working interest in this prospect.

In the Eastern Gulf of Mexico, we drilled the Fredericksburg exploration well. Target sands were reached but we did not encounter commercial hydrocarbons. This was the third prospect to be drilled in the area following earlier successes at Vicksburg and Shiloh. We remain optimistic about the potential of this emerging play and are currently working with Shell, the operator, to finalize 2009 plans for this area. We expect to drill an additional well here next year and have a feasibility study underway to assess development options for Vicksburg. We have a 25% interest in Vicksburg and a 20% interest in Shiloh and Fredericksburg.

Development of the Longhorn discovery continues and first production is expected mid-year 2009 with a peak production rate of approximately 200 mmcf/d gross (50 mmcf/d net to us). We have a 25% non-operated working interest here and ENI is the operator.

At Knotty Head, we plan to drill an appraisal well in 2009 when the first of our two new deep-water drilling rigs arrives. We have a 25% operated interest in the field.

Canada

Following the success of last winter's drilling program in the Horn River basin in northeast British Columbia, we decided to drill two horizontal wells this summer. The wells have been drilled and are currently being fraced with testing results expected before year-end. The results from these wells will be taken into consideration as we plan our upcoming winter program for the area.

This shale gas play has the potential to become one of the most significant shale gas plays in North America. It has been compared to the Barnett Shale in Texas by other operators in the area as it displays similar rock properties and play characteristics. We have approximately 88,000 acres in the Dilly Creek area of the Horn River basin with a 100% working interest. Further appraisal activity is required before these estimates can be finalized and commerciality established.

Our CBM production continues to increase and averaged 45 mmcf/d for the quarter. Since the beginning of the year, our production has increased approximately 60% as our existing wells dewater and we bring new ones on-stream. Performance is in line with expectations and underlines the increasing value of our CBM assets.

Offshore West Africa

Development of the Usan field, offshore Nigeria is fully underway. The field development plan includes a FPSO vessel with a storage capacity of two million barrels of oil. All major contracts for deep-water facilities are proceeding with detailed engineering and early procurement of equipment and materials. The Usan field is expected to come on stream in early 2012 and will ramp up to a peak production rate of 180,000 bbls/d (36,000 bbls/d net to us).

The Usan field development is located in OML 138 and is covered by the original production sharing contract for OPL 222 issued in 1993, with the Nigerian National Petroleum Corporation as concessionaire. The contract conveys the right to develop and produce crude oil and continue with exploration activity. We are currently processing three-dimensional seismic in anticipation of further exploratory drilling in the area in 2009. The Usan field was discovered in 2002 and is located approximately 100 km offshore in water depths ranging from 750 to 850 meters. Drilling of the development wells is expected to commence next year. Nexen has a 20% interest in exploration and development along with Elf Petroleum Nigeria Limited (20% and Operator), Chevron Petroleum Nigeria Limited (30%) and Esso Exploration and Production Nigeria (Offshore East) Limited (30%).

FINANCIAL RESULTS

Change in Net Income

(Cdn$ millions)	2008 vs. 2007 Three Months Ended September 30	Nine Months Ended September 30
Net Income at September 30, 2007	**403**	**892**
Favourable (unfavourable) variances:		
Production Volumes, After Royalties		
Crude Oil	(24)	120
Natural Gas	(9)	27
Change in Crude Oil Inventory	67	3
Total Volume Variance	34	150
Realized Commodity Prices		
Crude Oil	653	1,848
Natural Gas	50	116
Total Price Variance	703	1,964
Oil and Gas Operating Expense		
Conventional	(19)	(42)
Syncrude	(15)	(57)
Total Operating Expense Variance	(34)	(99)
Depreciation, Depletion, Amortization and Impairment		
Conventional	(34)	(31)
Syncrude	2	3
Other	(5)	(13)
Total Depreciation, Depletion, Amortization and Impairment Variance	(37)	(41)
Exploration Expense	(45)	(24)
Energy Marketing Contribution	(55)	(276)
Chemicals Contribution	(18)	(47)
General and Administrative Expense	315	82
Interest Expense	24	75
Current Income Taxes	162	(470)
Future Income Taxes	(503)	(280)
Other		
Increase in Fair Value of Crude Oil Put Options	20	30
Allowance for Doubtful Receivables	(38)	(38)
Other	(45)	(22)
Net Income at September 30, 2008	886	1,896

Significant variances in net income are explained further in the following sections.

OIL & GAS AND SYNCRUDE

Production (before royalties) [1]

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Crude Oil and NGLs (mbbls/d)				
United Kingdom	100.0	90.0	102.0	77.2
Yemen	54.1	69.8	58.0	73.3
Canada	16.0	17.0	16.2	17.3
United States	8.5	14.2	11.2	17.3
Other Countries	5.7	6.5	5.7	6.2
Long Lake Bitumen [2]	5.2	–	3.0	–
Syncrude (mbbls/d) [3]	22.9	25.2	20.4	21.9
	212.4	222.7	216.5	213.2
Natural Gas (mmcf/d)				
Canada	133	111	128	115
United States	70	98	94	95
United Kingdom	17	18	19	15
	220	227	241	225
Total Production (mboe/d)	249	261	257	251

Production (after royalties) [1]

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Crude Oil and NGLs (mbbls/d)				
United Kingdom	100.0	90.0	102.0	77.2
Yemen	29.9	39.0	30.3	41.8
Canada	12.0	12.9	12.3	13.5
United States	7.3	12.5	9.7	15.3
Other Countries	5.1	6.0	5.3	5.7
Long Lake Bitumen [2]	5.2	–	3.0	–
Syncrude (mbbls/d) [3]	18.9	21.1	17.3	18.8
	178.4	181.5	179.9	172.3
Natural Gas (mmcf/d)				
Canada	107	94	107	96
United States	60	83	80	81
United Kingdom	17	18	19	15
	184	195	206	192
Total Production (mboe/d)	209	214	214	204

Notes:
1 We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
2 Pre-operating revenues and costs associated with Long Lake bitumen are capitalized as development costs until we reach commercial operations.
3 Considered a mining operation for US reporting purposes.

Higher sales volumes increased net income for the quarter by $34 million

Production before royalties decreased 2% and 5% from the prior quarter and the third quarter of 2007, respectively. The decrease was primarily caused by lower production volumes in the Gulf of Mexico as a result of hurricanes in early September. Natural declines in Yemen were only partially offset by rising bitumen production at Long Lake, which averaged 5,200 bbls/d in the quarter. Production after royalties was comparable with the prior quarter, but was 2% lower than the third quarter of 2007.

Early in July, we sold approximately 850,000 barrels of crude oil inventory from our North Sea operations that was produced during the second quarter and carried as inventory at June 30, 2008.

The following table summarizes our production volume changes since the last quarter:

(mboe/d)	Before Royalties	After Royalties
Production, second quarter 2008	254	211
Production changes:		
Yemen	(3)	–
United States	(7)	(6)
Long Lake Bitumen	2	2
Syncrude	4	3
Other	(1)	(1)
Production, third quarter 2008	249	209

Production volumes discussed in this section represent before-royalties volumes, net to our working interest.

UNITED KINGDOM

The Buzzard platform consistently operated above the original design expectation and production was 4% higher from the previous quarter and 17% higher from the third quarter of 2007. Buzzard averaged uptime of approximately 96% and produced 89,600 boe/d during the quarter (207,500 boe/d gross). In early July, Buzzard was shut in for two days to complete a planned rig move. During the fourth quarter, we expect to have one week of downtime at Buzzard to carry out platform maintenance.

We have commenced work on a fourth platform at Buzzard which will contain production sweetening facilities designed to handle higher levels of hydrogen sulphide previously identified in the reservoir. Our share of the projected cost of the fourth platform is expected to be between US$350 million and US$400 million. The platform is expected to be in service in 2010.

At Scott/Telford, natural declines, combined with downtime for platform and subsea maintenance, reduced production volumes 28% and 41% as compared to the previous quarter and the third quarter of 2007, respectively. Production from our non-operated fields at Duart and Farragon averaged 4,400 boe/d for the quarter.

YEMEN

Masila production continues to decline consistent with expectations. We are targeting infill development drilling opportunities due to the maturity of the field. This resulted in production declines of 7% from the prior quarter and 20% from the third quarter of 2007. Our drilling program for 2008 is focusing our capital investment on existing fields to maximize reserve recoveries and economic returns. To date this year, we have drilled 13 development wells and plan to drill 10 additional wells in the fourth quarter. Production declines are expected to continue as we maximize recovery of the remaining reserves on the block, prior to contract expiry in 2011.

Block 51 production was consistent with the prior quarter but was 30% lower than the third quarter of 2007 due to natural decline rates and from drilling fewer development wells. We drilled four development wells at BAK A this year with two more planned before the end of the year.

CANADA

Production in Canada is 2% higher than the previous quarter and 8% higher than the same period last year. Our conventional production from our heavy oil and natural gas properties is consistent with the previous quarter and only slightly lower than the third quarter of 2007, as our capital investments offset natural declines. CBM production averaged 45 mmcf/d during the quarter, 12% higher than the previous quarter and 70% higher than the third quarter of 2007. Production continues to increase as our wells in the Fort Assiniboine area de-water and we bring additional development wells on stream.

UNITED STATES

Gulf of Mexico production volumes are 27% and 34% lower than the prior quarter and the same period last year, respectively, primarily due to hurricane-related downtime and damage. We were producing approximately 30,000 boe/d prior to Hurricanes Gustav and Ike. The hurricanes reduced our third quarter production by approximately 8,300 boe/d. A number of our properties have been brought back online, while others are ready to start production when pipelines are re-opened.

In the deep water, Gunnison received minor damage while at Aspen and Wrigley, third-party host facilities were damaged. These deep-water fields are expected to resume production this year, but timing is uncertain due to our reliance on third-party repairs. Our Green Canyon 6, 50 and 137 deep-water fields remain shut-in following the destruction of a third-party processing platform. We are currently evaluating alternative production options for these fields. On the shelf at Vermilion 321/340, there was substantial damage to the lower decks of some of the platforms. We do not expect production at this location to be restored until 2009. Production from these deep-water and shelf fields was approximately 5,600 boe/d prior to Hurricane Ike.

On the shelf, initial assessments indicate minor damage to a number of our other production facilities and subject to completing underwater assessments; we will make the necessary repairs and expect to restore production later this year.

For the fourth quarter, we expect our production volumes in the Gulf of Mexico to range between 10,000 and 20,000 boe/d. Production volumes are dependant on the timing of repair work and the readiness of third-party infrastructure, such as production platforms and pipelines. We carry insurance coverage for physical damage caused by hurricanes, subject to certain deductibles and limits.

OTHER COUNTRIES

Production from the Guando field in Colombia averaged 5,700 boe/d during the quarter, consistent with the prior quarter. Seven wells were shut in as a result of landslides earlier in the year. Three of these wells have been brought back on stream in the third quarter. Work is underway to bring the remaining wells back on stream. Under the terms of our license, our interest in the Guando field will decrease by half to 10% once the field has produced 60 million barrels, likely in mid 2009. This will reduce our share of reported production volumes.

LONG LAKE BITUMEN

Long Lake SAGD production continues to ramp up as we convert wells to bitumen production from steam circulation and as the reliability of the SAGD facilities improves. The bitumen reservoir is performing well, the reliability of our surface facilities is improving, steam injection rates are at their highest levels since SAGD start up and production rates are increasing. In the field, 45 of the total 81 well pairs have now been converted to SAGD operation, gross production rates averaged 15,200 bbls/d for the first half of October and recently exceeded 19,000 bbls/d (9,500 bbls/d, net to us). Bitumen production is expected to continue to increase during the fourth quarter. We are completing commissioning activities for the upgrader and we expect to begin producing premium synthetic crude oil in the fourth quarter.

SYNCRUDE

Syncrude production was 20% higher than the previous quarter following completion of a turnaround on Coker 8-1 and from performing maintenance activity on other units in the second quarter. Third quarter production was reduced slightly in July for a sulphur plant shutdown and again in September to complete a turnaround on Coker 8-2. Production was 9% lower than the third quarter of last year as a result of these production outages.

Commodity Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Crude Oil and NGLs				
West Texas Intermediate (WTI) (US$/bbl)	117.98	75.38	113.29	66.19
Differentials [1] (US$/bbl)				
Heavy Oil	17.74	23.04	20.55	19.87
Mars	5.38	5.83	6.42	4.58
Masila	5.01	0.66	3.75	(0.22)
Dated Brent (Brent)	3.20	0.51	2.27	(0.94)
Producing Assets (Cdn$/bbl)				
United Kingdom	114.89	78.06	108.21	73.08
Yemen	115.92	78.27	110.46	72.65
Canada	97.91	46.76	85.69	43.43
United States	122.46	74.43	110.29	65.90
Other Countries	120.11	76.29	108.03	68.42
Syncrude	126.56	82.09	120.12	76.77
Corporate Average (Cdn$/bbl)	115.56	75.86	108.36	70.17
Natural Gas				
New York Mercantile Exchange (NYMEX) (US$/mmbtu)	8.95	6.24	9.73	7.02
AECO (Cdn$/GJ)	8.76	5.32	8.13	6.46
Producing Assets (Cdn$/mcf)				
Canada	8.00	5.17	8.33	6.48
United States	10.14	6.75	10.28	8.03
United Kingdom	7.53	4.99	7.11	4.13
Corporate Average (Cdn$/mcf)	8.65	5.80	9.03	6.95
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	106.22	69.82	99.64	65.96
Average Foreign Exchange Rate				
Canadian to US Dollar (US$)	0.9599	0.9573	0.9817	0.9052

Note:
[1] These differentials are a discount/(premium) to WTI

Higher realized commodity prices increased quarterly net income by $703 million

Average commodity prices reduced slightly in the third quarter from their record levels. WTI decreased 5% from the second quarter but was 57% higher than the same period last year. Similarly, Brent crude oil prices were down 5% from the previous quarter but 53% higher than the third quarter of 2007. We realized $115.56/bbl for our crude oil sales in the quarter. This was only 2% lower than the previous quarter as the decrease in benchmark commodity prices was mitigated somewhat by the strengthening US dollar relative to the Canadian dollar.

While our third quarter realized gas price decreased 15% from the previous quarter, NYMEX fell 22%. As the US dollar strengthened against the Canadian dollar in the third quarter, it partially offset the NYMEX decline. When compared to the third quarter of 2007, our realized gas price was 49% higher while NYMEX prices increased 43%. AECO natural gas prices increased 65% from last year but were consistent with the second quarter averaging $8.76/GJ.

Compared to the previous quarter, the US dollar has strengthened relative to the Canadian dollar. As a result, our net sales increased by approximately $63 million and our realized crude oil and natural gas price increased by approximately $3.51/bbl and $0.26/mcf, respectively.

CRUDE OIL REFERENCE PRICES

Crude oil prices remained volatile during the third quarter. WTI ranged from a high of US$147.27/bbl in July down to a low of US$90.51/bbl in September. The quarterly average WTI price was US$117.98/bbl but trended downwards throughout the quarter to finish at US$100.64/bbl.

Some of the factors that contributed to the strength in crude oil prices this year include: 1) continuing strong demand from emerging markets, 2) limited supply growth, 3) low OPEC spare capacity, 4) geopolitical concerns, 5) inflation fears, 6) a weaker US dollar, and 7) investment money flows into commodities. Higher prices were considered necessary to ration demand in a supply-constrained environment where much of the non-OECD demand growth has been reduced. As crude prices increased, many countries, including China, India, Vietnam, Indonesia and Sri Lanka, had to reduce price subsidies because of the increased fiscal strain.

Recently the factors driving the strength in crude oil prices have diminished as a result of the global financial market turmoil and fears of a global economic recession. The instability of world financial markets presents a major risk to future global economic growth and the demand for commodities, including oil.

As commodity prices declined over the quarter, inflation concerns diminished. Central banks have shifted their focus from controlling inflation to stimulating and stabilizing the economy. Futures positions used as a hedge against the US dollar and inflation were unwound as expectations of slower European economic growth caused the US dollar to strengthen. Hedge and mutual fund liquidations, de-leveraging by financial institutions, and counterparties reducing exposures with troubled financial players also contributed to the downward pressure on prices.

Normal factors that impact crude oil prices such as geopolitical unrest and the threat of hurricane damage in the Gulf of Mexico had a minimal impact on price. Significant political events such as Russia's invasion of Georgia and Iran's continued nuclear program did little to move price. There was also little impact on commodity prices from Hurricanes Ike and Gustav, which caused substantial damage to producing assets in the Gulf of Mexico. These events have been overshadowed by the global financial market instability.

CRUDE OIL DIFFERENTIALS

In Canada, heavy oil differentials averaged US$17.74/bbl (15% of WTI) for the quarter, compared to US$23.04/bbl (31% of WTI) for the third quarter of 2007. Heavy oil differentials continued to trade at tight levels to WTI due to strong demand for heavier crudes and lower supply levels from delays in the ramp up of oil sands projects.

In the US Gulf Coast, the Mars differential continued to tighten and is now narrower than historic levels, averaging US$5.38/bbl (5% of WTI) for the quarter compared to US$5.83/bbl (8% of WTI) in the third quarter of 2007. The Yemen Masila differential widened relative to WTI, with Masila trading at a discount of US$5.01/bbl compared to a discount of US$0.66/bbl in the third quarter of 2007. The weakening Brent crude price compared to WTI contributed to wider Masila differentials, as Masila is typically priced off of Brent.

The Brent/WTI differential widened during the quarter, with Brent trading at a discount to WTI of US$3.20/bbl, compared to a discount of US$0.51/bbl for the third quarter of 2007. The differential was volatile during the quarter and Brent occasionally traded at a premium to WTI. Shipping displacements as a result of storms increased already high transportation costs and continue to support wider differentials.

NATURAL GAS REFERENCE PRICES

NYMEX natural gas prices averaged US$8.95/mmbtu for the quarter, compared to US$6.24/mmbtu for the third quarter of 2007. Similar to oil prices, natural gas prices peaked early in the quarter. Prices fell subsequently throughout the quarter and stabilized in the $7 to $8 range in September. Some of the factors contributing to lower natural gas prices include 1) lower crude oil prices, 2) unstable financial markets, 3) reduced power generation demand due to colder August weather in North America, and 4) supply increases in North American unconventional tight sand/shale gas production. Leading up to the price peak, domestic supply forecasts were lower than estimates of demand and natural gas prices rose on expectations that the North American consumers would have to pay higher gas prices to attract LNG cargoes from Europe. However, unexpected unconventional supply growth in North America has made this unlikely in the near term.

Operating Costs

(Cdn$/boe)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Operating costs based on our working interest production before royalties [1]				
Conventional Oil and Gas	8.75	7.81	8.38	7.93
Synthetic Crude Oil				
Syncrude	32.40	22.37	37.22	25.20
Average Oil and Gas	10.90	9.26	10.70	9.44
Operating costs based on our net production after royalties				
Conventional Oil and Gas	10.38	9.60	10.09	9.84
Synthetic Crude Oil				
Syncrude	39.23	26.73	44.01	29.31
Average Oil and Gas	12.96	11.34	12.87	11.65

Note:
[1] Operating costs per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

Higher oil and gas operating costs decreased net income for the quarter by $34 million

Operating costs have increased $34 million or 16% from the prior year, primarily due to higher expenditures at Syncrude and turnaround costs for our Scott platform in the North Sea.

In the UK North Sea, costs increased $16 million over last year. The majority of these additional expenses were due to platform maintenance at Scott and sub-sea maintenance in the Telford field. These costs added $0.22/boe to our corporate average. Slightly higher transportation tariffs for the Buzzard platform increased costs; however, as many of Buzzard's operating costs are fixed in nature, the higher production levels reduced our corporate average by $0.11/boe.

In Yemen, we continue to incur expenditures on maintaining existing wells to maximize reserve recoveries and slow the natural declines of the mature field. These costs, combined with declining production rates, increased the average operating cost by $0.30/boe. In the Gulf of Mexico, higher lease operating costs, additional surface facility maintenance and other expenses increased our costs relative to last year. Lower production as a result of the hurricane activity and the higher costs increased our corporate average by $0.75/boe.

In Canada, our operating costs last year included $7 million of expenses for the Balzac gas plant turnaround expenditures that were not incurred this year. However, higher costs were experienced this year in our heavy oil operations as a result of industry cost inflation, expenses related to new wells, down hole maintenance in our conventional gas assets, and higher activity in our CBM operations. Overall, the change in operating costs and higher production rates in Canada reduced our corporate average by $0.20/boe.

At Syncrude, operating costs increased $15 million over last year as a result of four factors: 1) temporary contracting costs to increase the mineable ore inventory for bitumen supply; 2) purchasing additional third-party bitumen to upgrade; 3) higher natural gas prices, and 4) unscheduled maintenance expenses. These higher expenses, combined with lower production, increased our corporate average by $0.90/boe.

US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weaker US dollar. This decreased our corporate average by $0.17/boe for the quarter.

Depreciation, Depletion, Amortization and Impairment (DD&A)

(Cdn$/boe)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
DD&A based on our working interest production before royalties [1]				
Conventional Oil and Gas	16.08	14.89	15.05	15.12
Synthetic Crude Oil				
Syncrude	6.10	6.40	6.47	6.59
Average Oil and Gas	15.17	14.05	14.36	14.58
DD&A based on our net production after royalties				
Conventional Oil and Gas	19.08	18.29	18.13	18.77
Synthetic Crude Oil				
Syncrude	7.38	7.65	7.65	7.67
Average Oil and Gas	18.03	17.21	17.27	17.74

Note:
[1] DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

Higher oil and gas DD&A decreased net income for the quarter by $32 million

Our DD&A expense was higher than last year, primarily as the result of higher sales volumes in our North Sea operations. UK crude oil and natural gas sales volumes were 27% higher than last year, increasing our quarterly DD&A expense by $41 million.

Our production mix between areas continues to change as a result of declining production rates in our Yemen operations, which have been offset by strong volumes from our North Sea assets. This change in production mix has increased our overall corporate average rate by $0.55/boe. Depletion rates at Buzzard are higher than our corporate average as they include our acquisition and project completion costs.

In the Gulf of Mexico, reserve revisions at the end of 2007 resulted in higher depletion rates, increasing our corporate average rate by $0.55/boe from last year. However, our total DD&A expense was $10 million lower in the quarter as a result of lower production rates caused by hurricane activity.

In Canada, our CBM projects in central Alberta continue to experience differences between the timing of capital expenditures on new wells and facilities and the recognition of associated reserves. This results in higher depletion rates earlier in a field's life and increased our quarterly corporate average DD&A rate by $0.22/boe from last year. We expect our depletion rate for our CBM projects to decline over time as we recognize additional proved reserves as we gain additional production experience to support increasing the estimated recovery factor of the gas in place.

The stronger Canadian dollar relative to the same period last year decreased our corporate average by $0.37/boe, as depletion of our international and US assets is denominated in US dollars.

Exploration Expense

(Cdn$/million)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Seismic	38	19	72	79
Unsuccessful Exploration Drilling	50	31	101	85
Other	24	17	72	57
Total Exploration Expense	112	67	245	221
New Growth Exploration	126	170	446	377
Geological and Geophysical Costs	38	19	72	79
Total Exploration Expenditures	164	189	518	456
Exploration Expense as a % of Exploration Expenditures	68%	35%	47%	48%

Higher exploration expense decreased net income for the quarter by $45 million

Our exploration program continues to focus on our two primary exploration areas: the North Sea and the Gulf of Mexico. Our third quarter exploration expense includes costs related to unsuccessful drilling.

In the Gulf of Mexico, we expensed $26 million of costs for the Fredericksburg well, located in the deep water. This well was drilled to a depth of 24,560 feet but failed to encounter commercial hydrocarbons and was subsequently abandoned. We are continuing to evaluate our Cote De Mer prospect in the Gulf of Mexico, but drilling was suspended during the quarter due to Hurricanes Gustav and Ike.

In the UK, we wrote off our Yeoman well for $6 million upon evaluating our development options for the discovery. Future development of Yeoman relied on the success of other exploration wells in the area. With no immediate success in the vicinity, we have no further plans to pursue development of the area.

Elsewhere in the UK North Sea, we made a discovery at Blackbird in the quarter and drilled successful exploration and sidetrack wells at Pink. We are currently evaluating development opportunities for the Blackbird and Pink discoveries. We have an 80% and 46% operated working interest in Blackbird and Pink, respectively.

Exploration expense in the Norwegian North Sea included $32 million to complete our summer seismic programs. Our exploration activity in Norway is focused on acquiring and processing seismic data that will enable us to identify drilling opportunities on our newly acquired blocks.

ENERGY MARKETING

(Cdn$/millions, except as indicated)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Physical Sales [1]	16,479	11,579	48,987	33,980
Physical Purchases [1]	(16,255)	(11,424)	(48,077)	(33,308)
Net Financial Transactions [1]	239	64	(365)	78
Change in Fair Market Value of Inventory	(314)	–	(164)	–
Net Revenue	149	219	381	750
Transportation Expense	(197)	(211)	(536)	(620)
Other	7	6	19	10
Net Marketing Revenue	(41)	14	(136)	140
Contribution to Net Marketing Revenue by Region				
North America	(53)	23	(131)	115
Asia	2	3	10	8
Europe	10	(12)	(15)	17
Net Marketing Revenue	(41)	14	(136)	140
Depreciation, Depletion, Amortization and Impairment	(4)	(3)	(11)	(10)
General and Administrative	4	(15)	(63)	(68)
Allowance for Doubtful Receivables	(38)	–	(38)	–
Marketing Contribution to Income before Income Taxes	(79)	(4)	(248)	62
North America				
Natural Gas				
Physical Sales Volumes [2] (bcf/d)	7.0	6.1	7.0	5.5
Transportation Capacity (bcf/d)	2.1	2.5	2.1	2.5
Storage Capacity (bcf)	49.3	43.0	49.3	43.0
Financial Volumes [3] (bcf/d)	12.5	21.9	19.2	21.8
Crude Oil				
Physical Sales Volumes [2] (mbbls/d)	626	651	623	658
Storage Capacity (mbbls)	3,242	2,554	3,242	2,554
Financial Volumes [3] (mbbls/d)	1,454	2,404	1,429	2,276
Power				
Physical Sales Volumes [2] (MW/d)	4,610	4,494	4,792	4,436
Generation Capacity (MW/hr)	177	177	177	177
Asia				
Physical Sales Volumes [2] (mbbls/d)	166	152	194	169
Financial Volumes [3] (mbbls/d)	365	195	324	229
Europe				
Financial Volumes [3] (mbbls/d)	216	462	970	407
Value-at-Risk				
Quarter-end	27	34	27	34
High	33	38	40	38
Low	19	28	19	24
Average	29	33	31	31

Notes:

1 Marketing's physical sales, physical purchases and net financial transactions are reported net on the Unaudited Consolidated Statement of Income as marketing and other.

2 Excludes intra-segment transactions. Physical volumes represent amounts delivered during the quarter.

3 Financial volumes represent amounts traded during the quarter.

Lower contribution from Energy Marketing decreased net income by $55 million
Over the last few months, we have been realigning our strategies and positions to better support our core physical business as a producer/marketer. We are working to reduce our trading levels and the overall size of our North American business. We are exiting positions that do not support our realigned focus. This is reflected in the quarterly financial results.

The overall quarterly contribution from North America is down due to losses in our natural gas business, which were partially offset by a strong contribution from our crude oil business:

- Losses in our natural gas business occurred as we worked to reduce trading exposures and to protect the value of some of our physical capacity contracts. Narrowing spreads between supply regions and consuming markets generated losses on certain physical basis contracts (commodity purchase and/or sales contract) over the next three years. We also recognized losses on natural gas financial contracts used to hedge our physical transportation capacity contracts. The offsetting gains on our physical capacity contracts cannot be recognized until they are used.
- Crude oil gains were driven primarily through blending activities and moving of product between markets. Our liquids business has been realizing the benefit of a clear focus on a physical marketing strategy over the last twelve months.

Compared to the same time last year, our North American natural gas and crude oil financial trading volumes are down by approximately 43% and 40%, respectively. Our European business has also seen improvements in their results with a clearer focus on our physical producer/marketer model. We have added physical capacity contracts, both storage and transportation, in the UK and continental Europe.

In September, Lehman Brothers filed for bankruptcy protection and our exposure to them in our trading operations was approximately $38 million. The entire amount was written off in the quarter however we continue to pursue recovery of these amounts. Given current conditions in credit markets, we are closely monitoring credit exposures. The majority of our counterparties are with integrated oil companies, crude oil refiners & marketers and large utilities.

Results from our marketing group vary by quarter and historical results are not necessarily indicative of results to be expected in future quarters. Quarterly marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

Composition of Net Marketing Revenue

	Three Months Ended September 30		Nine Months Ended September 30	
(Cdn$/millions)	**2008**	**2007**	**2008**	**2007**
Trading Activities	(49)	6	(157)	127
Other Activities	8	8	21	13
Net Marketing Revenue	(41)	14	(136)	140

Trading Activities
In marketing, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts not designated as hedges for accounting purposes using fair value accounting and record the change in fair value in marketing and other income. The fair value of these instruments is included with amounts receivable or payable and they are classified as long-term or short-term based on their anticipated settlement date.

Other Activities
We enter into fee for service contracts related to transportation and storage of third-party oil and gas. In addition, we earn income from our power generation facilities at Balzac and Soderglen.

Fair Value of Derivative Contracts
Wherever possible, the estimated fair value of our derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk. Where we have offsetting positions, we utilize a mid-market pricing convention as a basis for establishing fair value and adjust our pricing to the highest price when we have a net open sell position and the lowest price when we have a net open buy position. We also incorporate credit risk associated with counterparty default into our estimates of fair value. Inputs to fair valuations may be readily observable, market-corroborated, or generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange and the International Petroleum Exchange.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors, and broker quotations, which can be observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.
- Level 3 – Valuations in this level are based on inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

At September 30, 2008, the fair value of our derivative contracts in our energy marketing trading activities was $92 million. These derivatives economically hedge our physical storage and transportation contracts which cannot be carried at fair value until they are used. Below is a breakdown of the derivative fair value by valuation method and contract maturity.

(Cdn$ millions)	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Level 1 – Actively Quoted Markets	101	56	(21)	–	136
Level 2 – Based on Other Observable Pricing Inputs	(45)	(3)	4	–	(44)
Level 3 – Based on Unobservable Pricing Inputs	2	(2)	–	–	–
Total	58	51	(17)	–	92

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	Total
Fair Value at December 31, 2007	6
Change in Fair Value of Contracts	(1)
Net Losses (Gains) on Contracts Closed	99
Changes in Valuation Techniques and Assumptions [1]	(12)
Fair Value at September 30, 2008	92

Note:
[1] Our valuation methodology has been applied consistently in each period, with the exception of two portfolio level reserves that were included in the first quarter of 2008 to account for: a) credit risk associated with counterparty default; and b) liquidity risk in our portfolio.

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.5 years. Those maturing beyond one year primarily relate to North American natural gas positions.

CHEMICALS

Lower Chemicals contribution decreased net income by $18 million

Canexus' results increased over last year due to higher North American sodium chlorate and chlor-alkali sales volumes, as well as strong sales pricing. However, these gains were offset by foreign exchange losses on US-dollar denominated debt. Sales volumes and prices in our sodium chlorate business increased 8% and 10%, respectively, while chlor-alkali sales volumes and pricing increased 3% and 16%, respectively. Our operations in Brazil remain strong as a result of continued demand from Aracruz Cellulose, our primary customer. In Brazil, chlorate and chlor-alkali prices increased 21% and 20%, respectively from a year ago. Chlorate sales volumes increased 17% and chlor-alkali increased 8% over the same period.

Operating expenses increased from a year ago due to: 1) higher costs for electricity and natural gas; and 2) higher production volumes. Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products. Chemicals net income includes foreign exchange losses of $16 million (2007 – gains of $11 million) on Canexus US-dollar denominated debt.

CORPORATE EXPENSES

General and Administrative (G&A)

(Cdn$/millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
General and Administrative Expense before Stock-Based Compensation	100	84	286	263
Stock-Based Compensation [1]	(408)	(77)	(121)	(16)
Total General and Administrative Expense	(308)	7	165	247

Note:
[1] Includes expenses relating to the tandem option plan, stock options for our US-based employees and stock appreciation rights.

Lower G&A costs increased quarterly net income by $315 million
We account for our stock-based compensation programs using the intrinsic-value method and therefore fluctuating share prices create volatility in our net income. During the quarter, we recovered a substantial portion of the non-cash stock-based compensation costs that were previously expensed, as our share price decreased 39% from the end of the previous quarter. In the third quarter of 2007, we also had a recovery of stock-based compensation expense as our share price decreased 8%. Cash payments made in connection with our stock-based compensation programs during the quarter amounted to $2 million (2007 – $29 million) and year-to-date payments totaled $89 million (2007 – $116 million).

Interest and Financing Costs

(Cdn$/millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Interest	80	85	235	258
Less: Capitalized Interest	(64)	(45)	(176)	(124)
Net Interest Expense	16	40	59	134

Lower net interest expense increased net income by $24 million
Our financing costs were substantially unchanged from the third quarter of 2007. Interest capitalized on our Long Lake development project increased $11 million from the same period in 2007. The remainder of the increase in capitalized interest from last year relates to our oil and gas developments at Ettrick in the North Sea and at Usan, offshore West Africa. We will cease capitalizing interest on Ettrick and Long Lake Phase 1 once they are substantially complete. Our net interest expense should increase once these development projects are brought on stream.

Income Taxes

(Cdn$/millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Current	(26)	136	817	347
Future	645	142	583	303
Total Provision for Income Taxes	619	278	1,400	650
Effective Tax Rate (%)	41%	40%	42%	42%

Higher taxes decreased net income by $341 million, while the year-to-date effective tax rate remains at 42%
Our provision for income taxes increased $341 million as compared to the third quarter of 2007, although our current income taxes decreased by $162 million. Record commodity prices, combined with strong production at Buzzard, resulted in higher earnings in the UK which are taxable at 50%. During the third quarter, we completed an internal reorganization and financing of our assets in the North Sea which provided us an additional one-time tax deduction in the UK. This, together with falling commodity prices, will cause our expected 2008 tax liability to be lower than previously expected. As a result, we have reduced our current tax expense for the period by approximately $514 million. Our income tax provision also includes current taxes in Yemen and Colombia.

Other

(Cdn$/millions)	Three Months Ended September 30 2008	2007	Nine Months Ended September 30 2008	2007
Increase/(Decrease) in Fair Value of Crude Oil Put Options	9	(11)	(1)	(31)

During the first quarter of 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options establish a Brent floor price of US$60/bbl on these volumes, are settled annually and provide a base level of price protection without limiting our upside to higher prices. The put options were purchased for $14 million and are carried at fair value. In September 2008, Lehman Brothers filed for bankruptcy protection, which impacts approximately 36% (or 25,000 bbls/d) of our 2009 put options. The carrying value of these put options have been reduced to nil. At September 30, 2008, the remaining options had a fair value of $13 million, resulting in recognizing a gain of $9 million in the quarter. During the third quarter of 2007, the decrease in fair value resulted from a loss in value of crude oil put options purchased for 2008 production.

LIQUIDITY

Capital Structure

(Cdn$ millions)	September 30 **2008**	December 31 **2007**
Net Debt [1]		
Bank Debt	1,257	413
Senior Notes	3,956	3,758
Senior Debt	5,213	4,171
Subordinated Debt	473	439
Total Debt	5,686	4,610
Less: Cash and Cash Equivalents	(1,772)	(206)
Total Net Debt	3,914	4,404
Shareholders' Equity [2]	7,263	5,610

Notes:
1 Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.
2 At September 30, 2008 there were 520,969,101 common shares and US$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by issuing common shares at our option after November 8, 2008. The number of shares issuable depends on the common share price on the redemption date.

Net Debt

Our net debt levels are directly related to our operating cash flows and our capital expenditure activities. Changes in net debt are related to:

(Cdn$ millions)	
Cash Flow from Operating Activities	3,299
Capital Investment	(2,149)
Excess of Cash Flow over Capital Investment	1,150
Dividends on Common Shares	(66)
Issue of Common Shares	48
Foreign Exchange Translation of US-dollar Denominated Debt and Cash	(295)
Long-Term Capital Prepayments	(68)
Repurchase of Common Shares	(300)
Other	21
Decrease in Net Debt	490

Change in Working Capital

(Cdn$ millions)	September 30 **2008**	December 31 **2007**	Change
Cash and Cash Equivalents	1,772	206	1,566
Restricted Cash	65	203	(138)
Accounts Receivable	4,369	3,502	867
Inventories and Supplies	813	659	154
Accounts Payable and Accrued Liabilities	(4,475)	(4,135)	(340)
Income Taxes Payable	(70)	(45)	(25)
Other	69	22	47
Net Working Capital	2,543	412	2,131

Our cash and cash equivalents are significantly higher than at year end due to higher operating cash flows and borrowings made on our term credit facilities. Record commodity prices and strong production volumes contributed to higher operating cash flows. We also completed an internal reorganization and financing of our assets in the North Sea during the quarter, which required us to draw down approximately US$1 billion under our term credit facilities. This provided us with additional one-time tax deductions in the UK. Since the beginning of the year, accounts receivable and payable for our Energy Marketing group increased $580 million and $465 million, respectively. These increases are driven by record commodity prices which increase the value of our purchases and sales for both physical and financial contracts. The value of our commodity trading inventory is carried at fair value and was higher than year end as a result of strong crude oil prices and higher gas volumes in storage. We reduced the accrual for stock-based compensation programs by $226 million during the year, as our share price decreased 23% since year end.

Outlook for Remainder of 2008

We expect our 2008 full year production to be slightly below our previous guidance of between 260,000 and 280,000 boe/d before royalties. We expect to generate approximately $4.4 billion in cash flow (before remediation and geological and geophysical expenditures) in 2008.

Our future liquidity and ability to fund capital requirements are generally dependent upon operating cash flows, our existing cash on hand and our committed credit facilities. Given the long cycle time of some of our development projects and volatile commodity prices, it is not unusual in any year for capital expenditures to exceed our cash flow. Changes in commodity prices, particularly crude oil as it represents over 80% of our production, can impact our operating cash flows. We use short-term contracts to sell the majority of our oil and gas production, exposing us to short-term price movements. A US$1/bbl change in WTI increases or decreases our 2008 cash flow by approximately $39 million ($10 million for the remainder of the year). Our exposure to a $0.01 change in the US to Canadian dollar exchange rate increases or decreases our 2008 cash flow by approximately $42 million ($8 million for the remainder of the year). While commodity prices can fluctuate significantly in the short term, we believe that over the longer term, commodity prices will increase as a result of growth in world demand and delays or shortages in supply growth. We believe that our existing liquidity and balance sheet capacity provides us with the ability to fund our obligations during periods of lower commodity prices.

During the first nine months of 2008, our cash flow exceeded capital expenditures. We used free cash flow to repay debt, buy back shares and build cash. We currently have $1.8 billion of cash and cash equivalents on hand. We also maintain significant undrawn committed credit facilities. At September 30, 2008, we had unsecured term credit facilities of US$3 billion in place that are available until 2012, of which US$1 billion was drawn and $458 million were used to support outstanding letters of credit. We also have approximately $657 million of undrawn, uncommitted, unsecured credit facilities, of which $30 million were used to support outstanding letters of credit. The average length to maturity of our public debt is approximately 20 years and our earliest maturities comprise our term credit facilities. In June 2008, we repaid $125 million of maturing medium-term notes using cash on hand.

During the quarter, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid (Bid). Under the Bid, we are allowed to repurchase for cancellation up to 10% of our public float of common shares, or approximately 53 million common shares. Purchases under the Bid commenced August 6, 2008 and can be made until August 5, 2009. During the quarter, we purchased 10 million common shares at an average price of $30.05/share for a total cost of $300 million.

Contractual Obligations, Commitments and Guarantees

We have assumed various contractual obligations and commitments in the normal course of our operations and financing activities. We have included these obligations and commitments in our MD&A in our 2007 10-K. During 2008, we entered into additional work commitments of $740 million including non-discretionary capital spending for drilling, seismic, facilities

construction and other development commitments in our international operations. In addition, the development of the Usan field, offshore Nigeria has now commenced. As a result, we entered into additional work commitments related to the development of the Usan field totaling $860 million over the next four years. There have been no other significant developments since year end.

CONTINGENCIES

There are a number of lawsuits and claims pending, the ultimate result of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations. These matters are described in *Legal Proceedings* in Item 3 contained in our 2007 10-K. There have been no significant developments since year end.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In February 2008, the Accounting Standards Board (AcSB) confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been set up to manage this transition and to ensure successful implementation within the required timeframe. We will provide disclosures of the key elements of our plan and progress on the project as the information becomes available during the transition period.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations and financial position.

US Pronouncements

Effective December 31, 2006, we adopted the recognition and disclosure provisions of the Financial Accounting Standards Board (FASB) Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. We do not expect the adoption of the change in measurement date in 2008 to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 141 (revised), *Business Combinations*. Statement 141 (revised) establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements an amendment of ARB. No 51*. This statement clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement 133*. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts and details of credit-risk-related contingent features in their hedged positions. The statement also requires disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In October 2008, FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active.* This position clarifies the application of FASB statement 157 in a market that is not active and provides an example to illustrate key considerations in such a situation. This position is effective upon the issuance date of October 10, 2008. We have reviewed the position and have determined that the impact of adoption is not material on our results of operation or financial position.

EQUITY SECURITY REPURCHASES

In July, we received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid that allows us to repurchase up to approximately 53 million common shares during the period from August 6, 2008 to August 5, 2009. During the quarter, we repurchased and subsequently cancelled approximately 10 million common shares for proceeds of $300 million.

SUMMARY OF QUARTERLY RESULTS

	Three Months Ended							
	2006	**2007**				**2008**		
(Cdn$ millions)	Dec	Mar	Jun	Sep	Dec	Mar	Jun	Sep
Net Sales	920	1,140	1,399	1,446	1,598	1,870	2,071	2,213
Net Income	77	121	368	403	194	630	380	886
Earnings per Common Share ($/share)								
Basic	0.15	0.23	0.70	0.77	0.37	1.19	0.72	1.68
Diluted	0.14	0.22	0.68	0.75	0.36	1.17	0.70	1.66

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Management's Discussion and Analysis of Financial Condition and Results of Operations*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "*anticipate*", "*believe*", "*intend*", "*plan*", "*expect*", "*estimate*", "*budget*", "*outlook*", "*forecast*" or other similar words, and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our Yemen operations;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of current and long-term assets;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operations costs;
- future demand for chemical products;
- estimates on a per share basis;
- sales;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed or will come on-stream; and
- changes in any of the foregoing.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- market prices for oil and gas and chemical products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environment and other laws and regulations;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings; and
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures About Market Risk* in Item 7A of our 2007 Annual Report on Form 10-K. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on an assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, we undertake no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Nexen Inc.
Unaudited Consolidated Statement of Income
For the Three and Nine Months Ended September 30

(Cdn$ millions, except per share amounts)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Revenues and Other Income				
Net Sales	2,213	1,446	6,154	3,985
Marketing and Other (Note 16)	131	226	387	773
	2,344	1,672	6,541	4,758
Expenses				
Operating	341	283	998	862
Depreciation, Depletion, Amortization and Impairment	386	349	1,084	1,043
Transportation and Other	291	238	691	694
General and Administrative (Note 17)	(308)	7	165	247
Exploration	112	67	245	221
Interest (Note 7)	16	40	59	134
	838	984	3,242	3,201
Income before Income Taxes	1,506	688	3,299	1,557
Provision for Income Taxes				
Current	(26)	136	817	347
Future	645	142	583	303
	619	278	1,400	650
Net Income before Non-Controlling Interests	887	410	1,899	907
Less: Net Income Attributable to Non-Controlling Interests	(1)	(7)	(3)	(15)
Net Income	886	403	1,896	892
Earnings Per Common Share ($/share)				
Basic (Note 14)	1.68	0.77	3.59	1.69
Diluted (Note 14)	1.66	0.75	3.53	1.66

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Balance Sheet

(Cdn$ millions, except share amounts)	September 30 **2008**	December 31 **2007**
Assets		
Current Assets		
Cash and Cash Equivalents	1,772	206
Restricted Cash	65	203
Accounts Receivable (Note 2)	4,369	3,502
Inventories and Supplies (Note 3)	813	659
Other	163	89
Total Current Assets	7,182	4,659
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $8,566 (December 31, 2007 - $7,195)	13,968	12,498
Future Income Tax Assets	348	268
Deferred Charges and Other Assets (Note 4)	370	324
Goodwill	347	326
Total Assets	22,215	18,075
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 6)	4,475	4,135
Income Taxes Payable	70	45
Accrued Interest Payable	67	54
Dividends Payable	27	13
Total Current Liabilities	4,639	4,247
Long-Term Debt (Note 7)	5,686	4,610
Future Income Tax Liabilities	2,507	2,290
Asset Retirement Obligations (Note 9)	925	792
Deferred Credits and Other Liabilities (Note 10)	1,136	459
Non-Controlling Interests	59	67
Shareholders' Equity (Note 13)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2008 – 520,969,101 shares		
2007 – 528,304,813 shares	963	917
Contributed Surplus	2	3
Retained Earnings	6,531	4,983
Accumulated Other Comprehensive Loss	(233)	(293)
Total Shareholders' Equity	7,263	5,610
Commitments, Contingencies and Guarantees (Note 18)		
Total Liabilities and Shareholders' Equity	22,215	18,075

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Statement of Cash Flows
For the Three and Nine Months Ended September 30

(Cdn$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Operating Activities				
Net Income	886	403	1,896	892
Charges and Credits to Income not Involving Cash (Note 15)	693	404	1,547	1,286
Exploration Expense	112	67	245	221
Changes in Non-Cash Working Capital (Note 15)	(840)	253	(468)	(19)
Other	117	(30)	79	(253)
	968	1,097	3,299	2,127
Financing Activities				
Repayment of Short-Term Borrowings, Net	(4)	(60)	(4)	(152)
Proceeds from (Repayment of) Term Credit Facilities, Net	1,031	188	803	(767)
Repayment of Medium-Term Notes (Note 7)	–	(150)	(125)	(150)
Proceeds from Long-Term Notes	–	–	–	1,660
Proceeds from (Repayment of) Canexus Term Credit Facilities, Net	(9)	12	(19)	45
Proceeds from Canexus Notes (Note 7)	–	–	51	–
Dividends on Common Shares	(26)	(13)	(66)	(39)
Issue of Common Shares and Exercise of Tandem Options	8	4	48	44
Repurchase of Common Shares for Cancellation (Note 13)	(300)	–	(300)	–
Changes in Non-Cash Working Capital (Note 15)	10	–	10	–
Other	(2)	(8)	(11)	(43)
	708	(27)	387	598
Investing Activities				
Capital Expenditures				
Exploration and Development	(689)	(772)	(2,064)	(2,309)
Proved Property Acquisitions	–	(104)	(2)	(150)
Chemicals, Corporate and Other	(36)	(25)	(83)	(72)
Changes in Restricted Cash	196	(103)	143	(21)
Changes in Non-Cash Working Capital (Note 15)	(66)	(33)	(120)	11
Other	36	(1)	(61)	(15)
	(559)	(1,038)	(2,187)	(2,556)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	41	(18)	67	(98)
Increase in Cash and Cash Equivalents	1,158	14	1,566	71
Cash and Cash Equivalents – Beginning of Period	614	158	206	101
Cash and Cash Equivalents – End of Period	1,772	172	1,772	172

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Statement of Shareholders' Equity
For the Three and Nine Months Ended September 30

(Cdn$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Common Shares				
Balance at Beginning of Period	972	893	917	821
Issue of Common Shares	8	3	32	28
Proceeds from Tandem Options Exercised for Shares	–	1	16	16
Accrued Liability Relating to Tandem Options Exercised for Shares	1	(6)	16	26
Repurchased under Normal Course Issuer Bid (Note 13)	(18)	–	(18)	–
Balance at End of Period	963	891	963	891
Contributed Surplus				
Balance at Beginning of Period	2	5	3	4
Stock-Based Compensation Expense	–	–	–	1
Exercise of Tandem Options	–	(2)	(1)	(2)
Balance at End of Period	2	3	2	3
Retained Earnings				
Balance at Beginning of Period	5,953	4,435	4,983	3,972
Net Income	886	403	1,896	892
Dividends on Common Shares (Note 13)	(26)	(13)	(66)	(39)
Repurchase of Common Shares (Note 13)	(282)	–	(282)	–
Balance at End of Period	6,531	4,825	6,531	4,825
Accumulated Other Comprehensive Loss				
Balance at Beginning of Period	(274)	(253)	(293)	(161)
Opening Derivatives Designated as Cash Flow Hedges	–	–	–	61
Other Comprehensive Income/(Loss)	41	(51)	60	(204)
Balance at End of Period	(233)	(304)	(233)	(304)

Nexen Inc.
Unaudited Consolidated Statement of Comprehensive Income
For the Three and Nine Months Ended September 30

(Cdn$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Net Income	886	403	1,896	892
Other Comprehensive Income, Net of Income Taxes:				
Foreign Currency Translation Adjustment:				
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	221	(327)	365	(822)
Net Gains (Losses) on Hedges of Self-Sustaining Foreign Operations [1]	(180)	276	(305)	679
Cash Flow Hedges:				
Realized Mark-to-Market Gains Recognized in Net Income	–	–	–	(61)
Other Comprehensive Income/(Loss)	41	(51)	60	(204)
Comprehensive Income	927	352	1,956	688

[1] Net of income tax recovery for the three months ended September 30, 2008 of $26 million (2007 – net of income tax expense of $47 million) and net of income tax recovery for the nine months ended September 30, 2008 of $45 million (2007 – net of income tax expense of $113 million).

See accompanying notes to the Unaudited Consolidated Financial Statements.

1. ACCOUNTING POLICIES

Our Unaudited Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States GAAP on the Unaudited Consolidated Financial Statements is disclosed in Note 20. In the opinion of management, the Unaudited Consolidated Financial Statements contain all adjustments of a normal and recurring nature necessary to present fairly Nexen Inc.'s (Nexen, we or our) financial position at September 30, 2008 and December 31, 2007 and the results of our operations and our cash flows for the three and nine months ended September 30, 2008 and 2007.

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Unaudited Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, fair values of derivative contract assets and liabilities and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. The results of operations and cash flows for the three and nine months ended September 30, 2008 are not necessarily indicative of the results of operations or cash flows to be expected for the year ending December 31, 2008.

These Unaudited Consolidated Financial Statements should be read in conjunction with our Audited Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K. Except as described below, the accounting policies we follow are described in Note 1 of the Audited Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K.

Change in Accounting Policies

Inventories
In 2007, we adopted the Canadian Institute of Chartered Accountants (CICA) Section 3031 *Inventories* issued by the Canadian Accounting Standards Board (AcSB). Effective October 1, 2007, we began carrying the commodity inventories held for trading by our energy marketing group at fair value, less any costs to sell. This standard was adopted prospectively and our results for the first nine months of 2007 have not been restated for this change in accounting policy.

Capital Disclosures
On January 1, 2008, we prospectively adopted CICA Section 1535 *Capital Disclosures* issued by the AcSB. This Section establishes standards for disclosing information about an entity's objectives, policies and processes for managing its capital structure. The disclosures have been included in Note 8.

Financial Instruments Disclosures and Presentation
On January 1, 2008, we prospectively adopted the following new standards issued by the AcSB: *Financial Instruments – Disclosure* (Section 3862) and *Financial Instruments – Presentation* (Section 3863). These accounting standards replaced *Financial Instruments – Disclosure and Presentation* (Section 3861). The disclosures required by Section 3862 and 3863 provide additional information on the risks associated with our financial instruments and how we manage those risks. The additional disclosures required by these standards are provided in Notes 11 and 12.

New Accounting Pronouncements

In February 2008, the AcSB confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been set up to manage this transition and to ensure successful implementation within the required timeframe. We will provide disclosures of the key elements of our plan and progress on the project as the information becomes available during the transition period.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations and financial position.

2. ACCOUNTS RECEIVABLE

	September 30 **2008**	December 31 **2007**
Trade		
Marketing	3,083	2,501
Oil and Gas	1,046	819
Chemicals and Other	56	60
	4,185	3,380
Non-Trade	227	132
	4,412	3,512
Allowance for Doubtful Receivables	(43)	(10)
Total	4,369	3,502

3. INVENTORIES AND SUPPLIES

	September 30 **2008**	December 31 **2007**
Finished Products		
Marketing	721	577
Oil and Gas	18	14
Chemicals and Other	18	13
	757	604
Work in Process	4	3
Field Supplies	52	52
Total	813	659

4. DEFERRED CHARGES AND OTHER ASSETS

	September 30 **2008**	December 31 **2007**
Long-Term Energy Marketing Derivative Contracts (Note 11)	217	248
Long-Term Capital Prepayments	77	9
Crude Oil Put Options and Natural Gas Swaps (Note 11)	15	–
Asset Retirement Remediation Fund	13	13
Other	48	54
Total	370	324

5. SUSPENDED WELL COSTS

The following table shows the changes in capitalized exploratory well costs during the nine months ended September 30, 2008 and the year ended December 31, 2007, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Capitalized exploratory well costs are included in property, plant and equipment (PP&E).

	Nine Months Ended September 30 **2008**	Year Ended December 31 **2007**
Balance at Beginning of Period	326	226
Additions to Capitalized Exploratory Well Costs Pending the Determination of Proved Reserves	146	215
Capitalized Exploratory Well Costs Charged to Expense	(27)	(10)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(31)	(74)
Effects of Foreign Exchange	14	(31)
Balance at End of Period	428	326

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	September 30 **2008**	December 31 **2007**
Capitalized for a Period of One Year or Less	150	202
Capitalized for a Period of Greater than One Year	278	124
Balance at End of Period	428	326
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	8	5

As at September 30, 2008, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico ($102 million), our coalbed methane exploratory activities in Canada ($92 million), three exploratory blocks in the North Sea ($56 million), our interest in an exploratory block, offshore Nigeria ($19 million) and exploratory activities on Block 51 in Yemen ($9 million). These costs relate to projects with successful exploration wells for which we have not been able to record proved reserves. We are assessing all of these wells and projects, and are working with our partners to prepare development plans, drill additional appraisal wells or to assess commercial viability.

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30 **2008**	December 31 **2007**
Accrued Payables	2,908	2,546
Energy Marketing Derivative Contracts (Note 11)	723	413
Trade Payables	425	578
Stock-based Compensation (Note 17)	167	393
Other	252	205
Total	4,475	4,135

7. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	September 30 **2008**	December 31 **2007**
Term Credit Facilities (US$1,000 million) (a)	1,060	211
Canexus Limited Partnership Term Credit Facilities (US$186 million) (b)	197	202
Medium-Term Notes, due 2008 (c)	–	125
Canexus Notes, due 2013 (US$50 million) (d)	53	–
Notes, due 2013 (US$500 million)	530	494
Notes, due 2015 (US$250 million)	265	247
Notes, due 2017 (US$250 million)	265	247
Notes, due 2028 (US$200 million)	212	198
Notes, due 2032 (US$500 million)	530	494
Notes, due 2035 (US$790 million)	837	781
Notes, due 2037 (US$1,250 million)	1,325	1,235
Subordinated Debentures, due 2043 (US$460 million)	488	454
	5,762	4,688
Less: Unamortized Debt Issue Costs	(76)	(78)
Total	5,686	4,610

(a) Term credit facilities

We have unsecured term credit facilities of US$3 billion available to 2012, of which US$1 billion was drawn at September 30, 2008 (December 31, 2007 – US$214 million). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. The weighted-average interest rate on our term credit facilities was 3.5% for the three months ended September 30, 2008 (2007 – 5.9%) and 3.6% for the nine months ended September 30, 2008 (2007 – 5.9%). At September 30, 2008, $458 million of these facilities were utilized to support outstanding letters of credit (December 31, 2007 – $283 million).

(b) Canexus Limited Partnership term credit facilities

Canexus Limited Partnership (Canexus) has committed, secured term credit facilities of $410 million available until 2011. At September 30, 2008, $197 million (US$186 million) was drawn on these facilities (December 31, 2007 – $202 million). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus' assets. The credit facility also contains covenants with respect to certain financial ratios. The weighted-average interest rate on our term credit facilities was 4.6% for the three months ended September 30, 2008 (2007 – 6.2%) and 4.5% for the nine months ended September 30, 2008 (2007 – 6.2%).

(c) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes. Interest was payable semi-annually at a rate of 6.3% and the principal was repaid in the second quarter of 2008.

(d) Canexus notes, due 2013

During the second quarter of 2008, Canexus issued US$50 million of notes. Interest is payable quarterly at a rate of 6.57%, and the principal is to be repaid in May 2013. Canexus may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.20%.

(e) Interest expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Long-Term Debt	75	80	220	244
Other	5	5	15	14
	80	85	235	258
Less: Capitalized	(64)	(45)	(176)	(124)
Total	16	40	59	134

Capitalized interest relates to and is included as part of the cost of our oil and gas properties under development. The capitalization rates are based on our weighted-average cost of borrowings.

(f) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $657 million, none of which were drawn at September 30, 2008 (December 31, 2007 – nil). We utilized $30 million of these facilities to support outstanding letters of credit at September 30, 2008 (December 31, 2007 – $196 million). Interest is payable at floating rates. The weighted-average interest rate on our short-term borrowings was 3.6% for the three months ended September 30, 2008 (2007 – 5.8%) and 3.2% for the nine months ended September 30, 2008 (2007 – 5.8%).

8. CAPITAL DISCLOSURES

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects which require significant capital investment prior to cash flow generation and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on where we are in a particular development cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term debt, long-term debt and equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room permitting us to draw on credit lines as required;
- maintaining a reasonable level of leverage; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of shareholders' equity, short-term and long-term debt and cash and cash equivalents as follows:

	September 30 **2008**	December 31 **2007**
Net Debt [1]		
Bank Debt	1,257	413
Senior Notes	3,956	3,758
Senior Debt	5,213	4,171
Subordinated Debt	473	439
Total Debt	5,686	4,610
Less: Cash and Cash Equivalents	(1,772)	(206)
Total Net Debt	3,914	4,404
Shareholders' Equity	7,263	5,610

[1] Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities as well as interest coverage ratios.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure which is calculated using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the twelve months ended September 30, 2008, our net debt to cash flow from operating activities ratio was 1.0 times compared to 1.6 times at December 31, 2007. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether to implement a strategy to reduce our leverage and lower this ratio back to target levels. In the past, each time we exceeded our internal net debt to cash flow from operating activities target band, we successfully brought our leverage down through asset sales and capital investment management.

Our interest coverage ratio allows us to monitor our ability to fund the interest requirements associated with our debt. Our interest coverage strengthened in 2008 from 12.1 times at the end of 2007 to 18.1 times at September 30, 2008.

Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, depreciation, depletion, amortization and impairment (EBITDA) by interest expense before capitalized interest. EBITDA is a non-GAAP measure which is calculated using net income excluding interest expense, provision for income taxes, exploration expenses, depreciation, depletion, amortization and impairment (DD&A) and other non-cash expenses. The calculation of EBITDA is set out in the following table.

	Twelve Months Ended September 30 **2008**	Twelve Months Ended December 31 **2007**
Net Income	2,090	1,086
Add:		
Interest Expense	93	168
Provision for Income Taxes	1,542	792
Depreciation, Depletion, Amortization and Impairment	1,808	1,767
Exploration Expense	350	326
Other Non-Cash Expenses	(112)	(52)
EBITDA	5,771	4,087

9. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our property, plant and equipment are as follows:

	Nine Months Ended September 30 **2008**	Year Ended December 31 **2007**
Balance at Beginning of Period	832	704
Obligations Incurred with Development Activities	17	105
Expenditures Made on Asset Retirements	(30)	(23)
Accretion	41	44
Revisions to Estimates	102	79
Effects of Foreign Exchange	3	(77)
Balance at End of Period [1, 2]	965	832

[1] Obligations due within 12 months of $40 million (December 31, 2007 - $40 million) have been included in accounts payable and accrued liabilities.
[2] Obligations relating to our oil and gas activities amount to $916 million (December 31, 2007 – $786 million) and obligations relating to our chemicals business amount to $49 million (December 31, 2007 – $46 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,350 million (December 31, 2007 – $2,165 million). We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted, risk-free rate of 6.1%. Approximately $132 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

10. DEFERRED CREDITS AND OTHER LIABILITIES

	September 30 **2008**	December 31 **2007**
Deferred Tax Credit	649	–
Long-Term Energy Marketing Derivative Contracts (Note 11)	183	163
Deferred Transportation Revenue	68	82
Fixed-Price Natural Gas Contracts and Swaps (Note 11)	35	51
Defined Benefit Pension Obligations	62	57
Capital Lease Obligations	53	52
Long-Term Stock-based Compensation	–	2
Other	86	52
Total	1,136	459

During the quarter, we completed an internal reorganization and financing of our assets in the North Sea which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. Accordingly, we have deferred recognizing $649 million of tax credits in our consolidated income statement.

11. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments including accounts receivable, accounts payable, income taxes payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt are carried at cost or amortized cost. The carrying value of our short-term receivable and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The derivatives section below details our derivatives and fair values as at September 30, 2008. The fair values are included with accounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At September 30, 2008, the estimated fair value of our long-term debt was $4,940 million (December 31, 2007 – $4,692 million) as compared to the carrying value of $5,686 million (December 31, 2007 – $4,610 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

Derivatives

(a) Total carrying value of derivative contracts related to trading activities

The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	September 30 **2008**	December 31 **2007**
Accounts Receivable	781	334
Deferred Charges and Other Assets [1]	217	248
Total Derivative Assets	998	582
Accounts Payable and Accrued Liabilities	723	413
Deferred Credits and Other Liabilities [1]	183	163
Total Derivative Liabilities	906	576
Total Net Derivatives related to Trading Activities [2]	92	6

[1] These derivative contracts settle beyond 12 months and are considered non-current.

[2] Comprised of $107 million (2007 – $15 million) related to commodity contracts and losses of $15 million (2007 – $9 million loss) related to US-dollar forward contracts and swaps.

(b) Total carrying value of derivative contracts related to non-trading activities

The fair value and carrying amounts related to derivative instruments related to non-trading activities are as follows:

	September 30 **2008**	December 31 **2007**
Accounts Receivable	–	–
Deferred Charges and Other Assets [1]	15	1
Total Derivative Assets	15	1
Accounts Payable and Accrued Liabilities	27	28
Deferred Credits and Other Liabilities [1]	35	51
Total Derivative Liabilities	62	79
Total Net Derivatives related to Non-Trading Activities	(47)	(78)

[1] These derivative contracts settle beyond 12 months and are considered non-current.

Crude oil put options

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options establish an annual average Brent floor price of US$60/bbl on these volumes. In September 2008, Lehman Brothers filed for bankruptcy protection. This impacts approximately 36% (or 25,000 bbls/d) of our 2009 put options and the carrying value of these put options has been reduced to nil. In 2007, we purchased put options on 36 million barrels or approximately 100,000 bbls/d of our 2008 crude oil production. These options establish an annual average Dated Brent floor price of US$50/bbl on these volumes.

The put options are carried at fair value within amounts receivable and are classified as long-term or short-term based on their anticipated settlement date. Any change in fair value is included in marketing and other income.

	Notional Volumes	Term	Average Floor Price	Fair Value
	(bbls/d)		(US$/bbl)	(Cdn$ millions)
Dated Brent Crude Oil Put Options	100,000	2008	50	–
Dated Brent Crude Oil Put Options	45,000	2009	60	13
				13

Fixed-price natural gas contracts and natural gas swaps

We have fixed-price natural gas sales contracts and offsetting natural gas swaps that are not part of our trading activities. These sales contracts and swaps are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Any change in fair value is included in marketing and other income.

	Notional Volumes	Term	Average Price	Fair Value
	(Gj/d)		($/Gj)	(Cdn$ millions)
Fixed-Price Natural Gas Contracts	15,514	2008	2.46	(24)
	15,514	2009 – 2010	2.56 – 2.77	(35)
Natural Gas Swaps	15,514	2008	7.60	(3)
	15,514	2009 – 2010	7.60	2
				(60)

(c) Fair value of derivatives

Wherever possible, the estimated fair value of our derivative instruments is based on quoted market prices, and if not available, on estimates from third-party brokers. We utilize market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net open sell position and the bid price when we have a net open buy position. We incorporate the credit risk associated with counterparty default into our estimates of fair value. Inputs to fair valuations may be readily observable, market-corroborated, or generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange and the International Petroleum Exchange.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors, and broker quotations, which can be observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.
- Level 3 – Valuations in this level are based on inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value on a recurring basis for our trading and non-trading activities as at September 30, 2008. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Net Derivatives				
Trading Derivatives	136	(44)	–	92
Non-Trading Derivatives	–	(47)	–	(47)
Total Net Derivatives	136	(91)	–	45

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the nine months ended September 30, 2008 is provided below:

	Level 3
Fair Value at January 1, 2008	(7)
Realized and unrealized gains (losses)	5
Purchases, issuances and settlements	(3)
Transfers in and/or out of Level 3	5
Fair Value at September 30, 2008	–
Unsettled gains (losses) relating to instruments still held as of September 30, 2008	10

Transfers in and/or out represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

12. RISK MANAGEMENT

(a) Market Risk

We invest in significant capital projects, purchase and sell commodities, issue short and long-term debt and invest in foreign operations. These activities expose us to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage exposures to market risk that result from these activities.

The following market risk discussion relates primarily to commodity price risk and foreign exchange risk related to our financial instruments. Our exposure to interest rate risk is immaterial.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We periodically manage these risks by using derivative contracts such as commodity put options.

Our energy marketing group markets and trades crude oil, natural gas, NGLs, ethanol and power through physical purchase and sales contracts, as well as financial commodity contracts. These activities expose us to commodity price risk, as well as foreign currency risk and volatility within these markets. Our energy marketing group actively manages risk by utilizing energy and currency derivatives. We typically take advantage of location, time and quality spreads using physical and financial contracts. Our marketing group also tries to take advantage of volatility within commodity markets and can establish net open commodity positions to take advantage of existing market conditions.

Volatility within various commodity markets can vary and change over time. While this volatility gives us opportunities, it can also cause our results to vary significantly between periods. We attempt to manage the associated risk and take on positions based on market intelligence; however, it is possible that we could incur financial loss.

Open positions exist when not all contracted purchases and sales terms have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk sensitivities in our portfolio).

We manage the level of market risk through daily monitoring of our energy trading activities relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate assuming normal market conditions exist. Our VaR calculation estimates the maximum probable loss, given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility, correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices follow a statistical pattern of distribution;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We also use stress testing using extreme market movements which complements our VaR estimates. Stress testing is used to quantify potential unexpected losses from low probability market movements. Our VaR analysis incorporates our derivative positions, non-derivative transportation and storage contracts and assets, as well as our commodity trading inventories.

Our quarter end, high, low, and average VaR amounts for the three and nine months ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Value-at-Risk				
Quarter End	27	34	27	34
High	33	38	40	38
Low	19	28	19	24
Average	29	33	31	31

Foreign currency risk

Foreign exchange risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term and long-term borrowings.

In our oil and gas operations, we manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. At September 30, 2008, we had US$5,436 million of long-term debt issued in US dollars and a one cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $54 million, before income tax.

In our energy marketing group, the majority of the financial commodity contracts are denominated in US dollars. We enter into US-dollar forward contracts and swaps to manage this exposure.

We also have exposures to currencies other than the US dollar. A portion of our United Kingdom operating expenses, capital spending and future asset retirement obligations are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies.

(b) Credit Risk

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. The majority of our accounts receivable are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Approximately 85% of our accounts receivable are with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We assess the financial strength of our counterparties, including those involved in marketing and other commodity arrangements, and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event of a downgrade to a non-investment grade credit rating. Credit risk, including credit concentrations, is routinely reported to management. We also use standard agreements that allow for the netting of exposures associated with a single counterparty. We believe this minimizes our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance.

At September 30, 2008:

- over 96% of our credit exposures were investment grade;
- approximately 85% of our credit exposures were with integrated oil companies, crude oil refiners & marketers and large utilities; and
- only two counterparties individually made up more than 5% of our credit exposure, and one of these counterparties made up more than 10% of our credit exposure. Both counterparties are super major integrated oil companies with strong investment grade ratings.

In light of current market conditions, we have increased our monitoring of credit exposure. We review our counterparty credit risks daily to effectively limit our exposures. In September, Lehman Brothers filed for bankruptcy protection and our exposure at the time was approximately $38 million. This amount was written off in the quarter however we continue to pursue recovery of these amounts.

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as accounts receivable, as well as the fair value of derivative financial assets. There are no significant amounts past due at the balance sheet date for which we have not provided. Collateral received from customers at September 30, 2008 includes $62 million of cash and $603 million of letters of credit. The cash received is included in our accounts payable and accrued liabilities.

(c) Liquidity Risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due, and to engage in our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At September 30, 2008, we had $1.8 billion of cash and cash equivalents on hand. Approximately US$1 billion of this amount was a result of draws made on our term credit facilities, which were used for an internal reorganization and financing of our North Sea assets. In addition, we have undrawn term credit facilities of US$1.6 billion. These facilities are available until 2012. We also have $657 million of undrawn, uncommitted credit facilities, of which $30 million was supporting letters of credit at September 30, 2008.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at September 30, 2008:

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Long-Term Debt	5,762	–	–	1,257	4,505
Interest on Long-Term Debt [1]	6,708	286	572	572	5,278
Total	12,470	286	572	1,829	9,783

[1] Excludes interest on term credit facilities of $3.2 billion and Canexus LP term credit facilities of $410 million as the amounts drawn on the facilities fluctuate. As a result, we are unable to provide a reasonable estimate of the interest.

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Trading Derivatives	906	723	183	–	–
Non-Trading Derivatives	62	27	35	–	–
Total	968	750	218	–	–

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at September 30, 2008, we could be required to post collateral of up to $1.6 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely secures the payment of such amounts. In the event of a ratings downgrade, we have trading inventories and receivables that can be quickly monetized as well as significant undrawn credit facilities.

At September 30, 2008, collateral posted with counterparties includes $73 million of cash and $296 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. If there is a default, the cash is retained.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $65 million (December 31, 2007 – $203 million), which have been included in restricted cash.

13. SHAREHOLDERS' EQUITY

(a) Dividends

Dividends per common share for the three months ended September 30, 2008 were $0.05 per common share (2007 – $0.025). Dividends per common share for the nine months ended September 30, 2008 were $0.125 (2007 – $0.075). Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

(b) Normal Course Issuer Bid

In July 2008, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid (Bid). Under the Bid, we are allowed to repurchase for cancellation up to 10% of our public float of common shares, approximately 53 million shares. Purchases under the Bid commenced August 6, 2008 and can be made until August 5, 2009. Purchases can be made on the open market through the TSX and the New York Stock Exchange at the market price at the time of acquisition.

During the quarter, we purchased 10 million common shares at an average price of $30.05 per common share for a total cost of $300 million. Of the amount paid, $18 million reduced the book value of our common shares. The cost to repurchase common shares in excess of their average book value has been charged to retained earnings ($282 million).

14. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of shares)	**2008**	**2007**	**2008**	**2007**
Weighted-average number of common shares outstanding	525.9	527.4	528.3	526.8
Shares issuable pursuant to tandem options	19.6	25.7	24.9	27.0
Shares notionally purchased from proceeds of tandem options	(13.0)	(15.3)	(16.2)	(15.2)
Weighted-average number of diluted common shares outstanding	532.5	537.8	537.0	538.6

In calculating the weighted-average number of diluted common shares outstanding for the three and nine months ended September 30, 2008, we excluded 4,019,880 and 40,000 tandem options, respectively, because their exercise price was greater than the average common share market price in the period. In calculating the weighted-average number of diluted common shares outstanding for the three and nine months ended September 30, 2007, we excluded 80,000 and 45,445 tandem options respectively, because their exercise price was greater than the average common share market price in the period. During the periods presented, outstanding tandem options were the only potential dilutive instruments.

15. CASH FLOWS

(a) Charges and credits to income not involving cash

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Depreciation, Depletion, Amortization and Impairment	386	349	1,084	1,043
Stock-Based Compensation	(410)	(106)	(210)	(132)
Future Income Taxes	645	142	583	303
Change in Fair Value of Crude Oil Put Options	(9)	11	1	31
Net Income Attributable to Non-Controlling Interests	1	7	3	15
Allowance for Doubtful Accounts	38	(2)	34	(3)
Other	42	3	52	29
Total	693	404	1,547	1,286

(b) Changes in non-cash working capital

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Accounts Receivable	503	122	(821)	55
Inventories and Supplies	260	200	(128)	21
Other Current Assets	(64)	(29)	(80)	(18)
Accounts Payable and Accrued Liabilities	(862)	(96)	496	(156)
Income Taxes Payable	(745)	20	(71)	76
Accrued Interest Payable	12	3	13	14
Dividends Payable	–	–	13	–
Total	(896)	220	(578)	(8)
Relating to:				
Operating Activities	(840)	253	(468)	(19)
Financing Activities	10	–	10	–
Investing Activities	(66)	(33)	(120)	11
Total	(896)	220	(578)	(8)

(c) Other cash flow information

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Interest Paid	64	77	212	233
Income Taxes Paid	655	127	816	284

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $38 million for the three months ended September 30, 2008 (2007 – $19 million) and $72 million for the nine months ended September 30, 2008 (2007 – $79 million).

16. MARKETING AND OTHER INCOME

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Marketing Revenue, Net	149	219	381	750
Change in Fair Value of Crude Oil Put Options	9	(11)	(1)	(31)
Interest	7	10	20	29
Foreign Exchange Losses	(33)	(11)	(34)	(54)
Other	(1)	19	21	79
Total	131	226	387	773

17. STOCK BASED COMPENSATION

We account for our stock-based compensation programs using the intrinsic-value method and therefore fluctuating share prices create volatility in our net income. We recovered non-cash stock-based compensation costs that were previously expensed, of $410 million for the three months ended September 30, 2008 (2007 – $106 million) and $210 million for the nine months ended September 30, 2008 (2007 – $132 million). Cash payments made in connection with out stock-based compensation programs during the quarter amounted to $2 million (2007 – $29 million) and year-to-date payments totaled $89 million (2007 – $116 million). These amounts are included in general and administrative expense.

18. COMMITMENTS, CONTINGENCIES AND GUARANTEES

As described in Note 15 to the Audited Consolidated Financial Statements included in our 2007 10-K, there are a number of lawsuits and claims pending, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

19. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen is involved in activities relating to Oil and Gas, Energy Marketing, Syncrude and Chemicals in various geographic locations as described in Note 20 to the Audited Consolidated Financial Statements included in our 2007 Annual Report on Form 10-K.

Three months ended September 30, 2008

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	317	192	139	1,141	56	17	220	131	–	2,213
Marketing and Other	2	1	–	6	1	149	3	(12)	(19) [2]	131
Total Revenues	319	193	139	1,147	57	166	223	119	(19)	2,344
Less: Expenses										
Operating	39	48	29	66	2	10	68	79	–	341
Depreciation, Depletion, Amortization and Impairment	46	50	56	192	4	4	12	11	11	386
Transportation and Other	3	–	1	21	–	235	4	12	15	291
General and Administrative [3]	(20)	(66)	(28)	(19)	(45)	(4)	–	9	(135)	(308)
Exploration	2	5	41	18	46 [4]	–	–	–	–	112
Interest	–	–	–	–	–	–	–	3	13	16
Income (Loss) before Income Taxes	249	156	40	869	50	(79)	139	5	77	1,506
Less: Provisions for (Recovery of) Income Taxes	86	44	13	444	(3)	(20)	40	2	13	619
Less: Non-Controlling Interests	–	–	–	–	–	–	–	1	–	1
Net Income (Loss)	163	112	27	425	53	(59)	99	2	64	886
Identifiable Assets	365	6,301 [5]	1,951	6,502	536	4,468 [6]	1,218	541	333	22,215
Capital Expenditures										
Development and Other	29	245	46	189	35	2	19	24	10	599
Exploration	–	34	38	43	11	–	–	–	–	126
	29	279	84	232	46	2	19	24	10	725
Property, Plant and Equipment										
Cost	2,402	7,697	3,670	5,558	358	268	1,363	896	322	22,534
Less: Accumulated DD&A	2,220	1,725	2,072	1,456	95	72	232	495	199	8,566
Net Book Value	182	5,972 [5]	1,598	4,102	263	196	1,131	401	123	13,968

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $7 million, foreign exchange losses of $33 million, increase in the fair value of crude oil put options of $9 million and other losses of $2 million
[3] Includes recovery of stock-based compensation expense of $408 million.
[4] Includes exploration activities primarily in Norway and Colombia.
[5] Includes costs of $4,432 million related to our Synthetic group (Long Lake Phase 1 and future phases) which are not being depreciated, depleted or amortized.
[6] Approximately 85% of Marketing's identifiable assets are accounts receivable and inventories.

Nine months ended September 30, 2008

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	912	545	518	3,053	156	52	567	351	–	6,154
Marketing and Other	9	2	4	17	2	381	3	(13)	(18) [2]	387
Total Revenues	921	547	522	3,070	158	433	570	338	(18)	6,541
Less: Expenses										
Operating	129	137	77	186	7	33	208	221	–	998
Depreciation, Depletion, Amortization and Impairment	120	144	192	505	12	11	36	32	32	1,084
Transportation and Other	7	10	2	21	–	574	11	41	25	691
General and Administrative [3,4]	(9)	13	23	(7)	14	63	1	24	43	165
Exploration	2	41	70	42	90 [5]	–	–	–	–	245
Interest	–	–	–	–	–	–	–	8	51	59
Income (Loss) before Income Taxes	672	202	158	2,323	35	(248)	314	12	(169)	3,299
Less: Provisions for (Recovery of) Income Taxes	234	57	55	1,181	(3)	(72)	89	5	(146)	1,400
Less: Non-Controlling Interests	–	–	–	–	–	–	–	3	–	3
Net Income (Loss)	438	145	103	1,142	38	(176)	225	4	(23)	1,896
Identifiable Assets	365	6,301 [6]	1,951	6,502	536	4,468 [7]	1,218	541	333	22,215
Capital Expenditures										
Development and Other	61	855	180	410	73	3	39	57	23	1,701
Exploration	9	146	147	114	30	–	–	–	–	446
Proved Property Acquisition	–	2	–	–	–	–	–	–	–	2
	70	1,003	327	524	103	3	39	57	23	2,149
Property, Plant and Equipment										
Cost	2,402	7,697	3,670	5,558	358	268	1,363	896	322	22,534
Less: Accumulated DD&A	2,220	1,725	2,072	1,456	95	72	232	495	199	8,566
Net Book Value	182	5,972 [6]	1,598	4,102	263	196	1,131	401	123	13,968

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $20 million, foreign exchange losses of $34 million, decrease in the fair value of crude oil put options of $1 million and other losses of $3 million
[3] Includes a severance accrual of $7 million in connection with North Vancouver technology conversion project.
[4] Includes recovery of stock-based compensation expense of $121 million.
[5] Includes exploration activities primarily in Norway and Colombia.
[6] Includes costs of $4,432 million related to our Synthetic group (Long Lake Phase 1 and future phases) which are not being depreciated, depleted or amortized.
[7] Approximately 85% of Marketing's identifiable assets are accounts receivable and inventories.

Three months ended September 30, 2007

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	280	101	137	608	42	13	160	105	–	1,446
Marketing and Other	2	–	1	7	–	219	–	9	(12) [2]	226
Total Revenues	282	101	138	615	42	232	160	114	(12)	1,672
Less: Expenses										
Operating	43	49	21	50	2	7	53	58	–	283
Depreciation, Depletion, Amortization and Impairment	54	41	66	151	2	3	14	11	7	349
Transportation and Other	2	5	–	–	–	211	4	10	6	238
General and Administrative [3]	(7)	(10)	5	(2)	(3)	15	1	7	1	7
Exploration	–	4	33	12	18 [4]	–	–	–	–	67
Interest	–	–	–	–	–	–	–	3	37	40
Income (Loss) before Income Taxes	190	12	13	404	23	(4)	88	25	(63)	688
Less: Provisions for (Recovery of) Income Taxes	63	4	4	206	(3)	(1)	26	8	(29)	278
Less: Non-Controlling Interests	–	–	–	–	–	–	–	7	–	7
Net Income (Loss)	127	8	9	198	26	(3)	62	10	(34)	403
Identifiable Assets	378	4,961 [5]	1,786	4,616	272	2,983 [6]	1,190	470	215	16,871
Capital Expenditures										
Development and Other	32	304	98	136	20	1	12	13	11	627
Exploration	1	42	90	31	6	–	–	–	–	170
Proved Property Acquisition	–	–	104 [7]	–	–	–	–	–	–	104
	33	346	292	167	26	1	12	13	11	901
Property, Plant and Equipment										
Cost	2,148	6,265	2,921	4,576	243	230	1,324	809	314	18,830
Less: Accumulated DD&A	1,930	1,560	1,349	746	75	54	209	452	164	6,539
Net Book Value	218	4,705 [5]	1,572	3,830	168	176	1,115	357	150	12,291

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $10 million, foreign exchange losses of $11 million and decrease in the fair value of crude oil put options of $11 million.
[3] Includes recovery of stock-based compensation expense of $77 million.
[4] Includes exploration activities primarily in Nigeria, Norway and Colombia.
[5] Includes costs of $2,533 million related to our Synthetic group (Long Lake Phase 1 and future phases) which are not being depreciated, depleted or amortized.
[6] Approximately 77% of Marketing's identifiable assets are accounts receivable and inventories.
[7] Includes acquisition of producing properties in the Gulf of Mexico.

Nine months ended September 30, 2007

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	811	329	453	1,544	106	36	394	312	–	3,985
Marketing and Other	8	4	1	35	–	750	–	31	(56) [2]	773
Total Revenues	819	333	454	1,579	106	786	394	343	(56)	4,758
Less: Expenses										
Operating	127	130	75	156	6	26	151	191	–	862
Depreciation, Depletion, Amortization and Impairment	176	123	212	423	8	10	39	33	19	1,043
Transportation and Other	6	18	–	–	–	620	13	29	8	694
General and Administrative [3]	(10)	30	19	–	22	68	1	24	93	247
Exploration	5	18	95	50	53 [4]	–	–	–	–	221
Interest	–	–	–	–	–	–	–	9	125	134
Income (Loss) before Income Taxes	515	14	53	950	17	62	190	57	(301)	1,557
Less: Provisions for (Recovery of) Income Taxes	176	4	18	490	4	25	56	17	(140)	650
Less: Non-Controlling Interests	–	–	–	–	–	–	–	15	–	15
Net Income (Loss)	339	10	35	460	13	37	134	25	(161)	892
Identifiable Assets	378	4,961 [5]	1,786	4,616	272	2,983 [6]	1,190	470	215	16,871
Capital Expenditures										
Development and Other	95	976	365	434	35	2	27	39	31	2,004
Exploration	11	87	153	94	32	–	–	–	–	377
Proved Property Acquisition	–	–	104 [7]	46 [8]	–	–	–	–	–	150
	106	1,063	622	574	67	2	27	39	31	2,531
Property, Plant and Equipment										
Cost	2,148	6,265	2,921	4,576	243	230	1,324	809	314	18,830
Less: Accumulated DD&A	1,930	1,560	1,349	746	75	54	209	452	164	6,539
Net Book Value	218	4,705 [5]	1,572	3,830	168	176	1,115	357	150	12,291

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $29 million, foreign exchange losses of $54 million and decrease in the fair value of crude oil put options of $31 million.
[3] Includes recovery of stock-based compensation expense of $16 million.
[4] Includes exploration activities primarily in Nigeria, Norway and Colombia.
[5] Includes costs of $2,533 million related to our Synthetic group (Long Lake Phase 1 and future phases) which are not being depreciated, depleted or amortized.
[6] Approximately 77% of Marketing's identifiable assets are accounts receivable and inventories.
[7] Includes acquisition of producing properties in the Gulf of Mexico.
[8] Includes acquisition of additional interests in the Scott and Telford fields.

20. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Unaudited Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. The US GAAP Unaudited Consolidated Statement of Income and Balance Sheet and summaries of differences from Canadian GAAP are as follows:

(a) Unaudited Consolidated Statement of Income – US GAAP For the Three and Nine Months Ended September 30

(Cdn$ millions, except per share amounts)	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Revenues and Other Income				
Net Sales	2,213	1,446	6,154	3,985
Marketing and Other (vii); (viii)	366	226	470	771
	2,579	1,672	6,624	4,756
Expenses				
Operating (ii)	341	292	998	884
Depreciation, Depletion, Amortization and Impairment	386	349	1,084	1,043
Transportation and Other (viii)	291	238	687	694
General and Administrative (iii)	(272)	18	180	268
Exploration	112	67	245	221
Interest	16	40	59	134
	874	1,004	3,253	3,244
Income before Income Taxes	1,705	668	3,371	1,512
Provision for Income Taxes				
Current	(26)	136	817	347
Deferred (i) - (vii)	724	137	610	290
	698	273	1,427	637
Net Income before Non-Controlling Interests	1,007	395	1,944	875
Less: Net Income Attributable to Non-Controlling Interests	(1)	(7)	(3)	(15)
Net Income – US GAAP [1]	1,006	388	1,941	860
Earnings Per Common Share ($/share)				
Basic (Note 14)	1.91	0.74	3.67	1.63
Diluted (Note 14)	1.89	0.72	3.61	1.60

Note:
[1] **Reconciliation of Canadian and US GAAP Net Income**

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Net Income – Canadian GAAP	886	403	1,896	892
Impact of US Principles, Net of Income Taxes:				
Ineffective Portion of Cash Flow Hedges (i)	–	–	–	(2)
Pre-operating Costs (ii)	–	(7)	–	(15)
Inventory Valuation (vii)	146	–	56	–
Stock-based Compensation (iii)	(26)	(8)	(11)	(15)
Net Income – US GAAP	1,006	388	1,941	860

(b) Unaudited Consolidated Balance Sheet – US GAAP

(Cdn$ millions, except share amounts)	September 30 **2008**	December 31 **2007**
Assets		
Current Assets		
Cash and Cash Equivalents	1,772	206
Restricted Cash	65	203
Accounts Receivable	4,369	3,502
Inventories and Supplies (vii)	856	615
Other	163	89
Total Current Assets	7,225	4,615
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $8,959 (December 31, 2007 - $7,588) (ii); (v)	13,919	12,449
Goodwill	347	326
Deferred Income Tax Assets	348	268
Deferred Charges and Other Assets	370	324
Total Assets	22,209	17,982
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities (iii)	4,543	4,188
Income Taxes Payable	70	45
Accrued Interest Payable	67	54
Dividends Payable	27	13
Total Current Liabilities	4,707	4,300
Long-Term Debt	5,686	4,610
Deferred Income Tax Liabilities (i) – (vii)	2,474	2,230
Asset Retirement Obligations	925	792
Deferred Credits and Other Liabilities (iv)	1,211	534
Non-Controlling Interests	59	67
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2008 – 520,969,101 shares		
2007 – 528,304,813 shares	963	917
Contributed Surplus	2	3
Retained Earnings (i) – (vii)	6,469	4,876
Accumulated Other Comprehensive Loss (i); (iv)	(287)	(347)
Total Shareholders' Equity	7,147	5,449
Commitments, Contingencies and Guarantees		
Total Liabilities and Shareholders' Equity	22,209	17,982

(c) Unaudited Consolidated Statement of Comprehensive Income – US GAAP For the Three and Nine Months Ended September 30

(Cdn$ millions)	Three Months Ended September 30 **2008**	**2007**	Nine Months Ended September 30 **2008**	**2007**
Net Income – US GAAP	1,006	388	1,941	860
Other Comprehensive Income, Net of Income Taxes:				
Foreign Currency Translation Adjustment	41	(51)	60	(143)
Change in Mark to Market on Cash Flow Hedges (i)	–	–	–	(61)
Comprehensive Income	1,047	337	2,001	656

(d) Unaudited Consolidated Statement of Accumulated Other Comprehensive Loss – US GAAP

(Cdn$ millions)	September 30 **2008**	December 31 **2007**
Foreign Currency Translation Adjustment	(233)	(293)
Unamortized Defined Benefit Pension Costs (iv)	(54)	(54)
	(287)	(347)

Notes:

i. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. On January 1, 2007, we adopted the equivalent Canadian standard for derivative instruments.

Future sale of gas inventory: At December 31, 2006, we included $25 million of gains on cash flow hedges in accounts receivable. Accumulated Other Comprehensive Income (AOCI) includes the effective portion of $23 million ($16 million, net of taxes) and $2 million ($2 million, net of taxes) of the ineffective portion was included in our 2006 US GAAP net income. Under Canadian GAAP, these gains were recognized in the first quarter of 2007.

At September 30, 2008, there were no cash flow hedges in place.

ii. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to property, plant and equipment. Under US principles, these costs have been included in operating expenses. As a result:

- operating expenses include pre-operating costs of $9 million and $22 million for the three and nine months ended September 30, 2007, respectively ($7 million and $15 million, respectively, net of income taxes); and
- property, plant and equipment is lower under US GAAP by $30 million (December 31, 2007 – $30 million).

iii. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. We are also required to accelerate the recognition of stock-based compensation expense for all stock-based awards made to our retirement-eligible employees under Canadian GAAP. However, under US GAAP, the accelerated recognition for such employees is only required for stock-based awards granted on or after January 1, 2006. As a result under US GAAP:

- general and administrative expense is higher by $36 million and $15 million ($26 million and $11 million, respectively, net of income taxes) for the three and nine months ended September 30, 2008, respectively (2007 – higher by $11 million and $21 million, respectively, ($8 million and $15 million, respectively, net of income taxes)); and
- accounts payable and accrued liabilities are higher by $68 million as at September 30, 2008 (December 31, 2007 – $53 million).

iv. On December 31, 2006, we adopted the Financial Accounting Standards Board (FASB) Statement 158 *Employers' Accounting for Defined Benefit Pension and other Postretirement Plans* (FAS 158). At September 30, 2008, the unfunded amount of our defined benefit pension plans was $75 million. This amount has been included in deferred credits and other liabilities and $54 million, net of income taxes has been included in AOCI.

v. On January 1, 2003, we adopted FASB Statement 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent except for the adoption date which results in our property, plant and equipment under US GAAP being lower by $19 million.

vi. On January 1, 2007, we adopted FASB Interpretation 48, *Accounting for Uncertainty in Income Taxes* (FIN 48) with respect to FAS 109 *Accounting for Income Taxes* regarding accounting and disclosure for uncertain tax positions. On the adoption of FIN 48, we recorded a cumulative effect of a change in accounting principle of $28 million. This amount increased our deferred income tax liabilities, with a corresponding decrease to our retained earnings as at January 1, 2007 in our US GAAP – Unaudited Consolidated Balance Sheet. As at September 30, 2008, the total amount of our unrecognized tax benefit was approximately $227 million, all of which, if recognized, would affect our effective tax rate. As at September 30, 2008, the total amount of interest and penalties in relation to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP – Unaudited Consolidated Balance Sheet is approximately $11 million. We had no interest or penalties in the US GAAP – Unaudited Consolidated Statement of Income for the first nine months of 2008. Our income tax filings are subject to audit by taxation authorities and as at September 30, 2008 the following tax years remained subject to examination: (i) Canada – 1985 to date, (ii) United Kingdom – 2002 to date and

iii. United States – 2004 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next twelve months.

vii. Under Canadian GAAP, we began carrying our commodity inventory held for trading purposes at fair value, less any costs to sell, effective October 31, 2007. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result:

- marketing and other income is higher by $235 million and $87 million ($146 million and $56 million, net of income taxes) for the three months and nine months ended September 30, 2008, respectively; and
- inventories are higher by $43 million as at September 30, 2008 (December 31, 2007 – lower by $44 million).

viii. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Gains of $nil and $4 million for the three and nine months ended September 30, 2008 were reclassified from marketing and other income to transportation and other expense ($nil for the three and nine months ended September 30, 2007).

Changes in Accounting Policies – US GAAP

On January 1, 2008, we adopted FASB Statement 157 *Fair Value Measurements* which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The adoption of this statement did not have a material impact on our results of operations or financial position. The additional disclosures required by the statement are included in Note 11.

New Accounting Pronouncements – US GAAP

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. We do not expect the adoption of the change in measurement date in 2008 will have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 141 (revised), *Business Combinations*. Statement 141 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements, an amendment of ARB No. 51*. This statement clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities*, an amendment of FASB Statement 133. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts and details of credit-risk-related contingent features in their hedged position. The statement also requires the disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In October 2008, FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active.* This position clarifies the application of FASB statement 157 in a market that is not active and provides an example to illustrate key considerations in such a situation. This position is effective upon the issuance date of October 10, 2008. We have reviewed the position and have determined that the impact of adoption is not material on our results of operation or financial position.

Nexen Inc.
Oil and Gas Prices and Cash Netback [1]

(all dollar amounts in Cdn$ unless noted)	Quarters – 2008 1st	2nd	3rd	Quarters – 2007 1st	2nd	3rd	4th	Total Year 2007
PRICES:								
WTI Crude Oil (US$/bbl)	97.90	123.98	117.98	58.16	65.03	75.38	90.69	72.31
Nexen Average – Oil (Cdn$/bbl)	93.00	118.00	115.56	61.69	72.27	75.86	82.80	73.43
NYMEX Natural Gas (US$/mmbtu)	8.75	11.48	8.95	7.18	7.66	6.24	7.39	7.12
Nexen Average – Gas (Cdn$/mcf)	7.97	10.21	8.65	7.58	7.52	5.80	6.47	6.81
NETBACKS:								
Canada – Heavy Oil								
Sales (mbbls/d)	16.2	16.4	16.0	17.8	17.2	16.9	16.4	17.1
Price Received ($/bbl)	65.94	93.16	97.91	41.71	41.89	46.76	46.07	44.07
Royalties & Other	16.65	22.61	24.24	9.16	9.52	10.93	10.04	9.91
Operating Costs	15.76	17.17	16.99	13.65	15.14	14.53	15.22	14.62
Netback	33.53	53.38	56.68	18.90	17.23	21.30	20.81	19.54
Canada – Natural Gas								
Sales (mmcf/d)	127	126	133	118	116	112	124	118
Price Received ($/mcf)	7.57	9.67	8.00	7.16	7.06	5.17	5.88	6.32
Royalties & Other	1.18	1.53	1.52	1.26	1.09	0.78	0.86	1.00
Operating Costs	1.67	1.84	1.84	1.59	1.81	2.52	1.71	1.90
Netback	4.72	6.30	4.64	4.31	4.16	1.87	3.31	3.42
Yemen								
Sales (mbbls/d)	62.5	57.4	54.2	77.5	72.7	69.9	66.2	71.5
Price Received ($/bbl)	96.57	120.39	115.92	63.02	77.34	78.27	88.24	76.29
Royalties & Other	48.07	59.21	52.47	28.17	33.84	34.73	43.04	34.69
Operating Costs	7.76	8.80	7.82	6.07	6.29	6.72	7.24	6.56
In-country Taxes	11.82	17.45	16.11	6.38	9.89	10.03	12.18	9.52
Netback	28.92	34.93	39.52	22.40	27.32	26.79	25.78	25.52
Syncrude								
Sales (mbbls/d)	19.3	19.1	22.9	21.4	19.0	25.2	22.6	22.1
Price Received ($/bbl)	101.70	130.90	126.56	70.03	77.12	82.09	88.33	79.76
Royalties & Other	11.93	22.08	21.89	8.26	10.33	13.42	15.33	12.02
Operating Costs	35.16	45.09	32.40	24.40	29.91	22.37	27.52	25.80
Netback	54.61	63.73	72.27	37.37	36.88	46.30	45.48	41.94

[1] Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.

Nexen Inc.
Oil and Gas Cash Netback [1] (continued)

(all dollar amounts in Cdn$ unless noted)	Quarters – 2008 1st	2nd	3rd	Quarters – 2007 1st	2nd	3rd	4th	Total Year 2007
United States								
Crude Oil:								
Sales (mbbls/d)	13.7	11.3	8.5	21.6	16.0	14.1	13.9	16.4
Price Received ($/bbl)	94.07	120.77	122.46	58.49	68.18	74.43	84.33	69.83
Natural Gas:								
Sales (mmcf/d)	112	99	70	101	86	98	119	101
Price Received ($/mcf)	9.03	11.80	10.14	8.58	8.85	6.75	7.27	7.80
Total Sales Volume (mboe/d)	32.4	27.8	20.2	38.4	30.4	30.5	33.8	33.3
Price Received ($/boe)	71.10	91.08	86.75	55.44	61.04	56.28	60.32	58.16
Royalties & Other	9.53	12.88	12.30	6.78	7.71	7.28	8.13	7.45
Operating Costs	8.20	9.28	15.62	8.11	9.46	7.40	8.78	8.43
Netback	53.37	68.92	58.83	40.55	43.87	41.60	43.41	42.28
United Kingdom								
Crude Oil:								
Sales (mbbls/d)	108.9	89.0	107.0	58.8	87.2	83.6	94.5	81.1
Price Received ($/bbl)	93.38	118.24	114.89	64.33	74.07	78.06	84.06	76.30
Natural Gas:								
Sales (mmcf/d)	22	24	18	13	13	16	21	16
Price Received ($/mcf)	6.82	7.06	7.53	3.87	3.32	4.99	5.84	4.71
Total Sales Volume (mboe/d)	112.6	93.0	110.0	60.8	89.3	86.3	98.0	83.7
Price Received ($/boe)	91.67	114.95	112.99	62.92	72.75	76.56	82.29	74.79
Operating Costs	5.67	7.42	6.71	9.60	6.59	6.28	6.23	6.94
Netback	86.00	107.53	106.28	53.32	66.16	70.28	76.06	67.85
Other Countries								
Sales (mbbls/d)	6.0	5.7	5.7	5.8	6.2	6.5	6.2	6.2
Price Received ($/bbl)	91.85	113.18	120.11	59.81	68.04	76.29	79.74	71.29
Royalties & Other	7.46	8.95	9.42	4.80	5.62	6.46	6.60	5.90
Operating Costs	4.74	4.43	5.14	2.97	3.39	3.34	4.13	3.45
Netback	79.65	99.80	105.55	52.04	59.03	66.49	69.01	61.94
Company-Wide								
Oil and Gas Sales (mboe/d)	270.1	240.4	250.9	241.5	254.1	253.9	263.9	253.4
Price Received ($/boe)	85.90	108.26	106.22	59.13	68.48	69.82	75.50	68.46
Royalties & Other	14.87	19.92	16.98	12.26	12.65	13.02	14.37	13.10
Operating Costs	9.46	11.89	10.90	9.67	9.41	9.26	9.46	9.45
In-country Taxes	2.74	4.16	3.48	2.05	2.83	2.76	3.05	2.69
Netback	58.83	72.29	74.86	35.15	43.59	44.78	48.62	43.22

[1] Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.

Nexen Inc.

Production Volumes (before royalties) [1]

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Crude Oil and NGLs (mbbls/d)				
United Kingdom	100.0	90.0	102.0	77.2
Yemen	54.1	69.8	58.0	73.3
Canada	16.0	17.0	16.2	17.3
United States	8.5	14.2	11.2	17.3
Other Countries	5.7	6.5	5.7	6.2
Long Lake Bitumen	5.2	–	3.0	–
Syncrude (mbbls/d) [2]	22.9	25.2	20.4	21.9
	212.4	222.7	216.5	213.2
Natural Gas (mmcf/d)				
Canada	133	111	128	115
United States	70	98	94	95
United Kingdom	17	18	19	15
	220	227	241	225
Total Production (mboe/d)	249	261	257	251

Production Volumes (after royalties)

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	**2007**	**2008**	**2007**
Crude Oil and NGLs (mbbls/d)				
United Kingdom	100.0	90.0	102.0	77.2
Yemen	29.9	39.0	30.3	41.8
Canada	12.0	12.9	12.3	13.5
United States	7.3	12.5	9.7	15.3
Other Countries	5.1	6.0	5.3	5.7
Long Lake Bitumen	5.2	–	3.0	–
Syncrude (mbbls/d) [2]	18.9	21.1	17.3	18.8
	178.4	181.5	179.9	172.3
Natural Gas (mmcf/d)				
Canada	107	94	107	96
United States	60	83	80	81
United Kingdom	17	18	19	15
	184	195	206	192
Total Production (mboe/d)	209	214	214	204

Notes:
[1] We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
[2] Considered a mining operation for US reporting purposes.

Cash Flow from Operations [1]

(Cdn$ millions)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Oil & Gas and Syncrude				
United Kingdom	1,056	563	2,857	1,416
Yemen [2]	195	171	543	511
Canada	131	35	344	130
United States	93	109	405	355
Other Countries	45	29	108	61
Marketing	(65)	(7)	(216)	64
Syncrude	151	102	350	229
	1,606	1,002	4,391	2,766
Chemicals	28	26	60	62
	1,634	1,028	4,451	2,828
Interest and Other Corporate Items	(56)	(89)	(203)	(276)
Income Taxes [3]	107	(71)	(578)	(173)
Cash Flow from Operations [1]	1,685	868	3,670	2,379

[1] Defined as cash flow from operating activities before changes in non-cash working capital and other. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other and excludes items of a non-recurring nature. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt. Cash flow from operations may not be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Cash Flow from Operating Activities	968	1,097	3,299	2,127
Changes in Non-Cash Working Capital	840	(253)	468	19
Other	(117)	30	(79)	253
Amortization of Premium for Crude Oil Put Options	(6)	(6)	(18)	(20)
Cash Flow from Operations	1,685	868	3,670	2,379
Weighted-average Number of Common Shares Outstanding (millions of shares)	525.9	527.4	528.3	526.8
Cash Flow from Operations Per Common Share ($/share)	3.20	1.65	6.95	4.52

[2] After in-country cash taxes of $81 million for the three months ended September 30, 2008 (2007 – $65 million) and $239 million for the nine months ended September 30, 2008 (2007 – $174 million).

[3] Excludes in-country cash taxes in Yemen.

CORPORATE INFORMATION

OFFICERS

Francis M. Saville, Q.C.
Chair of the Board

Charles W. Fischer
President and
Chief Executive Officer

Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

Laurence Murphy
Executive Vice President,
International Oil and Gas

Roger D. Thomas
Executive Vice President,
North America

Gary H. Nieuwenburg
Senior Vice President, Synthetic
Crude

Kevin J. Reinhart
Senior Vice President, Corporate
Planning and Business Development

Brian C. Reinsborough
Senior Vice President,
United States Oil and Gas

Tim J. Thomas
Senior Vice President, Canadian Oil
and Gas

Randy J. Jahrig
Vice President, Human Resources
and Corporate Services

Kim D. McKenzie
Vice President and Chief Information
Officer

Eric B. Miller
Vice President, General Counsel and
Secretary

Una M. Power
Treasurer

Brendon T. Muller
Controller

Rick C. Beingessner
Assistant Secretary

Sylvia L. Groves
Assistant Secretary

DIRECTORS

Charles W. Fischer

Dennis G. Flanagan

David A. Hentschel

S. Barry Jackson

Kevin J. Jenkins

The Hon. A. Anne McLellan, P.C.

Eric P. Newell, O.C.

Thomas C. O'Neill

Francis M. Saville, Q.C.

Richard M. Thomson, O.C.

John M. Willson

Victor J. Zaleschuk

For more information on our officers and directors, please see Item 10 in our Form 10-K or visit www.nexeninc.com.

WEBSITE

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com.

Hard copies may be ordered via the Investor section of our website or by calling 403.699.5931.

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STOCK SYMBOL: NXY

Toronto Stock Exchange
New York Stock Exchange

SUBORDINATED NOTES

7.35% due 2043
TSX: NXY.PR.U
NYSE: NXYPRB

DIVIDEND REINVESTMENT PLAN

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or on the internet at www.cibcmellon.com

AUDITORS

Deloitte & Touche LLP
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