nexen

Q3 INTERIM REPORT

For three months ended September 30, 2009

Current Production at Annual High Following Start-up of New Projects

(Cdn$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Production before Royalties (mboe/d)[1]	214	249	235	257
Production after Royalties (mboe/d)[1]	184	209	206	214
Net Sales	1,097	2,213	3,345	6,154
Cash Flow from Operations[2]	379	1,685	1,379	3,670
Per Common Share ($/share)	0.73	3.20	2.65	6.95
Net Income	122	886	277	1,896
Per Common Share ($/share)	0.23	1.68	0.53	3.59
Capital Expenditures, including Acquisitions[3]	671	763	2,933	2,221
Net Debt[4]	5,532	3,914	5,532	3,914
Common Shares Outstanding (millions of shares)	521.8	521.0	521.8	521.0

[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, geological and geophysical costs, and expenditures for other property, plant and equipment.
[4] Defined as long-term debt and short-term borrowings less cash and cash equivalents.

In the third quarter, we made significant progress in advancing our strategies. We successfully executed the planned turnaround at Long Lake, announced the largest discovery in the UK North Sea in the last ten years and lowered our breakevens on our Horn River shale gas play. We also started up Ettrick in the North Sea and added production from infill drilling at Telford. In the Gulf of Mexico, Longhorn recently came on stream. Our current production is at an annual high.

Quarterly cash flow was $379 million and net income was $122 million compared to $1.7 billion and $886 million a year ago. The decrease reflects the impact of lower production, lower commodity prices and some significant items included in income last year. In the third quarter, WTI averaged US$68/bbl compared to US$118/bbl a year ago. Last year, our cash flow included a one-time income tax recovery and earnings included a recovery of stock-based compensation.

Production for the third quarter averaged 214,000 boe/d (184,000 boe/d after royalties). Volumes were lower due to turnarounds and maintenance activities at a number of our fields. At Buzzard, production was shut-in for four weeks for the installation of the jacket for the fourth platform. At Scott/Telford, we completed a major turnaround which resulted in the fields being shutdown for approximately five weeks. The fields are back on-stream and additional production from the recently announced Telford step-out well has allowed us to almost double our production from the Scott platform. At Long Lake, we successfully completed the previously announced turnaround to replace valves, clean-out our hot lime softeners, isolate our water treatment trains and perform a number of other planned maintenance activities to improve reliability and operability. With the turnaround complete we have resumed steaming our wells and bitumen volumes are ramping up. In the Gulf of Mexico, maintenance activities at third party operated facilities impacted production from Wrigley and Aspen.

With the completion of these activities and the start up of new production, current production is 275,000 boe/d and growing. With production ramping up at Ettrick, Longhorn and Long Lake, we expect fourth quarter production volumes to be strong.

On the exploration front, the Golden Eagle area has emerged as a significant development opportunity. We expect development of the area will be economic with oil prices as low as US$40/bbl and require standalone facilities due to its size with project sanction targeted for 2010. Offshore West Africa, we have completed drilling the Owowo South B-1 well and expect to announce drilling results shortly. In the deepwater Gulf of Mexico, we are currently drilling the Knotty Head appraisal well and the Appomattox prospect in the Eastern Gulf. We expect results in the first half of 2010.

The Board of Directors declared a quarterly dividend of $0.05 per common share payable January 1, 2010, to shareholders of record on December 10, 2009.

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 19 to the Unaudited Consolidated Financial Statements. The date of this discussion is October 27, 2009.

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 is also presented.

Note: Canadian investors should read the Special Note to Canadian Investors on page 79 of our 2008 Annual Report of Form 10-K (2008 Form 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, except as indicated)	**2009**	**2008**	**2009**	**2008**
Production before Royalties (mboe/d)	214	249	235	257
Production after Royalties (mboe/d)	184	209	206	214
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	63.00	106.22	56.89	99.64
Cash Flow from Operating Activities	461	968	1,359	3,299
Net Income Attributable to Nexen Inc.	122	886	277	1,896
Earnings per Common Share, Basic ($/share)	0.23	1.68	0.53	3.59
Capital Investment	655	725	2,119	2,149
Acquisition of Additional Interest in Long Lake	–	–	755	–
Net Debt [1]	5,532	3,914	5,532	3,914

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

Planned maintenance and turnaround activity in the UK North Sea, Long Lake and the Gulf of Mexico temporarily reduced our production during the third quarter. Production was approximately 39,000 boe/d lower (based on production rates immediately prior) as a result of these activities. In the North Sea, the shut down of Buzzard and Scott/Telford was designed to coincide with a six week slowdown for routine maintenance on the Forties pipeline. During the shutdown, we successfully completed the fourth platform jacket installation and tie in at Buzzard and performed planned maintenance at Scott/Telford. With this work behind us and the start-up of Ettrick towards the end of the quarter, we are currently producing approximately 275,000 boe/d and we expect production to remain strong throughout the remainder of the year.

Commodity prices were slightly higher than the previous quarter, but were considerably lower than a year ago. Our realized quarterly oil and gas price increased 3% from the prior quarter to average $63.00/boe, but it remains approximately 40% below last year's realized price. With 85% of our production weighted to oil, we continue to be highly levered to increasing oil prices.

Our capital investment during the quarter focused on developing our Usan project offshore Nigeria, advancing our shale gas knowledge and capabilities, and appraising the Golden Eagle area discoveries in the UK North Sea. We are currently reviewing development options for the Golden Eagle area, which includes our Hobby and Pink discoveries. We are also making significant progress with our shale gas project in the Dilly Creek area of the Horn River basin in north-east British Columbia. During the quarter, we concluded a three-well drilling and completion program and now have five shale gas wells on-stream. In the Eastern Gulf of Mexico, we are currently drilling an exploratory well at Appomattox, about six miles west of our discovery at Vicksburg. Our Longhorn development in the Gulf of Mexico recently came on stream in late October.

At Long Lake, we achieved a major milestone at the end of August, when the solvent de-asphalter and thermal cracker units were successfully put into operation. As a result, we expect our PSC™ yield to increase to our design yield of approximately 80%. In September, we successfully completed the previously announced turnaround to replace valves, clean-out our hot lime softeners, isolate our water treatment trains and perform a number of other planned maintenance activities to improve reliability and operability. We also completed the installation of electric submersible pumps (ESPs) in some of our SAGD wells. With the turnaround complete we have resumed steaming our wells and bitumen volumes are ramping up.

Our financial position remains strong. We have available liquidity of approximately US$3.3 billion, comprised of cash on hand and undrawn lines of credit. We have no significant debt maturities until 2012 and the average term-to-maturity of our long-term debt is approximately 17 years. We believe our significant liquidity, combined with strong operating cash netbacks, provides us with the financial flexibility to carry out our investment programs.

CAPITAL INVESTMENT

Our strategy is to build a sustainable energy company focused in three areas: oil sands, unconventional gas and select conventional exploration and exploitation. We are committed to growing long-term value for our shareholders responsibly and are advancing our plans to achieve this as described below.

In 2009, we brought both Ettrick in the North Sea and Longhorn in the Gulf of Mexico on stream. We are currently investing primarily in:

- ramping up Long Lake safely and reliably;
- developing our Usan project and continuing to explore our additional acreage, offshore Nigeria;
- advancing appraisal of our Golden Eagle, Hobby and Pink discoveries in the UK North Sea;
- targeting a number of exploration prospects, primarily in the North Sea and Gulf of Mexico; and
- advancing our Horn River shale gas play in north-east British Columbia.

Details of our capital programs are set out below:

Three Months Ended September 30, 2009

	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
United Kingdom	12	–	32	121	165
Nigeria	129	–	1	–	130
Synthetic (mainly Long Lake) [1]	101	15	–	–	116
Canada	–	–	42	19	61
United States	25	–	46	6	77
Yemen	–	–	–	11	11
Other Countries	–	–	8	1	9
Syncrude	–	–	–	17	17
	267	15	129	175	586
Chemicals	53	–	–	–	53
Energy Marketing, Corporate and Other	–	–	–	16	16
Total Capital	320	15	129	191	655
As a % of Total Capital	49%	2%	20%	29%	100%

[1] Includes $72 million of capitalized start-up costs.

Nine Months Ended September 30, 2009

	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Long Lake Acquisition	755	–	–	–	755
United Kingdom	114	6	109	271	500
Nigeria	326	–	20	–	346
Synthetic (mainly Long Lake) [1]	366	78	1	–	445
Canada	–	2	188	73	263
United States	94	–	111	12	217
Yemen	–	–	–	62	62
Other Countries	–	–	30	2	32
Syncrude	–	–	–	56	56
	1,655	86	459	476	2,676
Chemicals	161	–	–	–	161
Energy Marketing, Corporate and Other	–	–	–	37	37
Total Capital	1,816	86	459	513	2,874
As a % of Total Capital	63%	3%	16%	18%	100%

[1] Includes $223 million of capitalized start-up costs.

United Kingdom – North Sea

Our Ettrick development in the North Sea produced first oil in mid August and we have tested the floating production, storage and offloading vessel (FPSO) up to its design rates. Field production will ramp-up as we commission the gas system. We have a 2008 discovery at Blackbird which could be a future tie-back to Ettrick. We operate both Ettrick and Blackbird, with a 79.73% working interest in each.

The Golden Eagle area has emerged as a significant development opportunity. We expect development of the area will be economic with oil prices as low as US$40/bbl and require standalone facilities due to its size. Project sanction is targeted for 2010. Appraisal activity continues and we have now drilled 13 wells in the area.

As we move into 2010, we are finalizing exploration plans to drill the North Uist prospect, west of the Shetland Islands and the Brand prospect in the Norwegian North Sea. These prospects have target sizes well above our typical North Sea target size.

Offshore West Africa

Development of the Usan field on block OML 138, offshore Nigeria is fully underway. The field development plan includes a FPSO vessel with a storage capacity of two million barrels of oil. Development drilling is underway and the FPSO hull is under construction. The Usan field is expected to come on stream in 2012 and will ramp up to a peak production rate of 180,000 bbls/d (36,000 bbls/d net to us). Nexen has a 20% interest in exploration and development on this block and Total E&P Nigeria Limited is the operator.

Earlier this year, we completed drilling an exploration well in the southern portion of Oil Prospecting License (OPL) 223, offshore West Africa. The Owowo South B-1 well was drilled in a water depth of 670 metres and is located 20 kilometres northeast of the Usan field, currently under development. We expect to announce drilling results shortly.

Under the production sharing contract governing OPL 223, the Nigerian National Petroleum Corporation (NNPC) is concessionaire of the license, which is operated by Total Exploration & Production Nigeria Ltd. Nexen has an 18% interest in the well. As is typical in many jurisdictions, the Nigerian Government is reviewing its existing petroleum fiscal terms, the impact of which on our projects is not yet known.

Synthetic

The turnaround at Long Lake is complete and we have resumed steaming our wells. Steam production is increasing. Bitumen production is back up to pre-turnaround rates of 10,000 to 12,000 bbls/d (gross) (6,500 to 7,800 bbls/d net to Nexen) and growing. The upgrader has recently restarted.

The turnaround activities focused on replacing valves, cleaning out the hot lime softeners and isolating the water treatment trains, and we performed a number of other planned maintenance activities to improve reliability and operability. These activities were successfully completed within the period of scheduled downtime. We also installed ESPs in a number of our SAGD wells. This will allow us to have better pressure control and ultimately reduce our overall steam-to-oil ratio ("SOR").

In addition, we recently completed the steam de-bottleneck project which will increase our SAGD steam production capacity to over 230,000 bbls/d. Start-up of the de-bottleneck project will proceed as required to support the SAGD ramp-up. We continue to expect a long-term SOR of 3.0 over the life of the project.

With respect to the Upgrader, we have now operated all units including the solvent de-asphalter and the thermal cracker. These units are necessary to achieve our target yield of approximately 80%. In addition, Syngas is being used in all SAGD operations. This allows us to decrease operating costs by reducing the requirement for purchased natural gas.

Phase 1 of our Long Lake project is designed to produce 72,000 bbls/d of gross bitumen, upgraded to approximately 60,000 bbls/d (39,000 bbls/d, net to us) of PSC™. We have a 65% interest in the project and the joint venture lands. We are the sole operator of the resource and the upgrader. We expect Long Lake will generate significant value with 40 years of production at a $10/bbl margin advantage.

Canada – Horn River Shale Gas

Following the conclusion of our recent three-well drilling and completion program, we continue to make significant progress on our substantial Horn River shale gas position in north-east British Columbia. With five shale gas wells now on-stream, we are producing approximately 15 mmcf/d with the majority of production coming from the three new wells. These wells have a higher frac density than our earlier wells. Our land position here has the potential to support 500 to 700 wells.

Substantial cost savings and productivity improvements were realized with this drilling and completion program. We took advantage of improved equipment utilization, drilled longer wells, initiated more fracs per well and maintained an industry-leading frac pace of 26 fracs in 15 days while achieving a 100% success rate on our frac program.

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 our reserve estimates can be finalized and commerciality established.

United States – Gulf of Mexico

In late October, we started production from the Longhorn development. The field is expected to reach peak production of approximately 200 mmcf/d or 33,000 boe/d gross (50 mmcf/d or 8,000 boe/d, net to us) early next year. We have a 25% non-operated working interest in this project and ENI is the operator.

In the Gulf of Mexico, the arrival of the Ensco 8501 rig has allowed us to start drilling our Knotty Head appraisal well. The well spud earlier this month and we expect results in the second quarter of 2010. A second deep-water drilling rig is expected to arrive in mid 2010. This will allow us to start drilling more of our identified prospects.

In the Eastern Gulf, we recently spud the Appomattox prospect, which is located six miles west of our Vicksburg discovery. Drilling results are expected early next year. During the quarter, we completed drilling the Antietam prospect. The well encountered thick good quality sand, but was wet. We have a 25% interest in Vicksburg and a 20% interest in Appomattox and Shiloh, an earlier discovery. Shell operates all three discoveries.

FINANCIAL RESULTS

Change in Net Income

	2009 vs. 2008	
	Three Months Ended September 30	Nine Months Ended September 30
Net Income at September 30, 2008	886	1,896
Favorable (unfavorable) variances[1]:		
Realized Commodity Prices		
Crude Oil	(581)	(1,994)
Natural Gas	(106)	(266)
Total Price Variance	(687)	(2,260)
Production Volumes, After Royalties		
Crude Oil	(310)	(379)
Natural Gas	17	(30)
Changes in Crude Oil Inventory Pending Sale	(112)	(114)
Total Volume Variance	(405)	(523)
Oil and Gas Operating Expense	3	15
Oil and Gas Depreciation, Depletion, Amortization and Impairment	38	(63)
Exploration Expense	23	26
Energy Marketing Revenue, Net	130	389
Chemicals Contribution	24	46
General and Administrative Expense [2]	(421)	(215)
Interest Expense	(68)	(167)
Current Income Taxes	(216)	303
Future Income Taxes	726	980
Other		
Decrease in Fair Value of Crude Oil Put Options	(32)	(217)
Other	121	67
Net Income at September 30, 2009	122	277

[1] All amounts are presented before provision for income taxes.
[2] Includes stock-based compensation expense.

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	
	2009	**2008**	**2009**	**2008**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	73.7	100.0	91.6	102.0
Yemen	48.7	54.1	51.5	58.0
Canada	14.2	16.0	14.9	16.2
United States	9.5	8.5	10.6	11.2
Long Lake Bitumen [2]	5.5	5.2	7.6	3.0
Other Countries	2.6	5.7	3.9	5.7
Syncrude (mbbls/d) [3]	22.5	22.9	19.1	20.4
	176.7	212.4	199.2	216.5
Natural Gas (mmcf/d)				
United Kingdom	17	17	18	19
Canada	143	133	139	128
United States	63	70	58	94
	223	220	215	241
Total Production (mboe/d)	214	249	235	257

Production (after royalties)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	73.7	100.0	91.6	102.0
Yemen	28.3	29.9	31.0	30.3
Canada	10.9	12.0	11.6	12.3
United States	8.5	7.3	9.6	9.7
Long Lake Bitumen [2]	5.5	5.2	7.6	3.0
Other Countries	2.4	5.1	3.6	5.3
Syncrude (mbbls/d) [3]	20.0	18.9	17.6	17.3
	149.3	178.4	172.6	179.9
Natural Gas (mmcf/d)				
United Kingdom	17	17	17	19
Canada	137	107	130	107
United States	56	60	52	80
	210	184	199	206
Total Production (mboe/d)	184	209	206	214

[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] Currently considered a mining operation for US reporting purposes.

Lower volumes decreased net income for the quarter by $405 million

Production before royalties was 11% lower from the prior quarter and 14% lower from the third quarter of 2008. Our production was primarily lower due to previously announced planned turnarounds and maintenance activities at a number of our fields. At Buzzard, we were impacted by routine Forties pipeline maintenance. During this downtime, we installed the jackets for the fourth platform. At Scott/Telford, we completed a major turnaround which resulted in the field being shutdown for approximately five weeks. Elsewhere, a planned turnaround was completed late in the third quarter at Long Lake and in the Gulf of Mexico, maintenance activities at third-party hosted facilities impacted production from the Aspen and Wrigley fields. Lower volumes were partially offset by: i) first oil from Ettrick; ii) a step-out development well at Telford; iii) increased shale gas production at Horn River; and iv) higher production at Syncrude, following the completion of a turnaround in the first half of the year.

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

(mboe/d)	Before Royalties	After Royalties
Production, second quarter 2009	240	208
Production changes:		
Syncrude	8	7
Canada	-	1
United Kingdom	(24)	(24)
Long Lake Bitumen	(4)	(4)
Yemen	(3)	(1)
United States	(2)	(2)
Other	(1)	(1)
Production, third quarter 2009	214	184

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

UNITED KINGDOM

Production volumes in the UK North Sea were approximately 25% lower as a result of previously announced downtime for maintenance and turnaround activity at Buzzard and Scott/Telford.

Our share of production from the Buzzard field averaged approximately 60,000 boe/d (138,000 boe/d gross) during the quarter. This was 32% lower than the previous quarter and 34% lower than the third quarter of 2008. The lower production was due to four weeks of planned downtime, scheduled to coincide with a six week slowdown of the Forties pipeline for routine maintenance. During the downtime, we successfully installed the jackets for the fourth platform and prepared the tie-ins. This platform will allow us to handle higher levels of hydrogen sulphide and maintain peak production until at least 2014. Buzzard production has since returned to full rates and is currently producing between 200,000 and 220,000 boe/d gross.

Production at Scott/Telford was 6% lower from the prior quarter as the platform was shut down for approximately five weeks for planned maintenance, coinciding with the Forties pipeline shutdown. Scott/Telford production increased 9% compared to the third quarter of 2008 primarily due to new production from a step-out development well at Telford. This well was completed in September and is tied back to our Scott platform. Production from our non-operated fields at Duart and Farragon averaged 1,700 boe/d for the quarter.

The Ettrick field began producing in mid August. Ettrick contributed 5,800 boe/d during the quarter and has been successfully produced at rates that allowed us to test the design capacity of the floating production, storage and offloading vessel (FPSO). In addition, we have a nearby discovery at Blackbird which could be a future tie-back to Ettrick, further enhancing the economics of this development.

YEMEN

Yemen production decreased 5% and 10% from the prior quarter and the third quarter of 2008, respectively. The decline is consistent with our expectations as the fields mature and as we drill fewer development wells. In the third quarter of 2009, we drilled one development well. Production declines are expected to continue as we focus on maximizing recovery of the remaining reserves.

CANADA

Production in Canada has remained flat. Slightly lower conventional production from our heavy oil properties was offset somewhat by increasing coalbed methane (CBM) production. CBM production for the quarter averaged 52 mmcf/d, 7 mmcf/d higher than the same period in 2008 and consistent with the prior quarter.

We continue to make significant progress on our substantial Horn River shale gas position in north-east British Columbia. During the quarter, we concluded a three-well drilling and completion program. We now have five shale gas wells on-stream and are producing approximately 15 mmcf/d with the majority of production coming from the three new wells.

LONG LAKE

Bitumen production for the quarter averaged 5,500 boe/d (8,500 boe/d gross), down 3,800 boe/d from the prior quarter, while the facility sold approximately 3,200 boe/d (4,900 boe/d gross) of bitumen and 1,900 boe/d (2,900 boe/d gross) of premium synthetic crude (PSC™).

Production volumes decreased as a result of water treatment issues and a previously announced turnaround in September. During the turnaround, we replaced valves, cleaned hot lime softeners, isolated water treatment trains and performed a number of other planned maintenance activities to improve reliability and operability. We installed ESPs in a number of our SAGD wells. With the turnaround complete we have resumed steaming the wells and bitumen volumes are back up to pre-turnaround levels of 10,000 to 12,000 bbls/d (gross) (6,500 to 7,800 bbls/d net to Nexen).

The last two major upgrader units, the solvent de-asphalter and thermal cracker, were successfully put into operation at the end of August. This allows us to transition from gasifying vacuum residue, which contains some lighter parts of the barrel, to gasifying asphaltenes, the heaviest part of the barrel. As a result, we expect our PSC™ yield to increase to our target yield of approximately 80%.

In addition, we recently completed the steam de-bottleneck project which will increase our SAGD steam production capacity to over 230,000 bbls/d. Start-up of the de-bottleneck project will proceed as required to support the SAGD ramp-up.

UNITED STATES

Gulf of Mexico production volumes were 10% lower than the prior quarter. In the deep water, maintenance activities at third-party hosted facilities impacted production from the Aspen and Wrigley fields. These declines were partially offset by producing for a full quarter on the shelf at Eugene Island 295, as production was brought back on stream at the end of June, following last year's hurricane damage.

Production volumes were 1% lower than the third quarter of 2008 as our Green Canyon 6, 50 and 137 deep-water fields remain shut-in following Hurricane Ike in 2008, which caused the destruction of the third–party processing platform. Production is expected to return in late 2010 or 2011, after reconstruction of the platform is completed. This decrease was substantially offset as Aspen production increased during the full quarter as compared to the same period last year when hurricane interruptions curtailed production. Aspen production is also higher as a result of additional water handling facilities being installed on the third-party platform earlier this year. At the end of the third quarter 2009, production in the Gulf of Mexico was approximately 22,000 boe/d.

Production from our non-operated Longhorn development has now started. The development is a four–well subsea tie-back to the Corral platform located 19 miles northwest of the field. The field is expected to reach peak production of approximately 200 mmcf/d or 33,000 boe/d gross (50 mmcf/d or 8,000 boe/d, net to us) early next year.

OTHER COUNTRIES

Our share of production from the Guando field in Colombia averaged 2,600 boe/d during the quarter, 1,000 boe/d lower than the prior quarter and 3,100 boe/d lower than the third quarter of 2008. The lower volumes reflect the reduced working interest of the Guando field effective in the second quarter of 2009. Under the terms of our license, our working interest in the Guando field decreased from 20% to 10% in May 2009 after cumulative production from the field reached 60 million barrels.

SYNCRUDE

Syncrude production was 51% higher than the previous quarter and 2% lower than the third quarter of 2008. Production volumes were higher than the previous quarter when we had; i) a scheduled turnaround on Coker 8-3; ii) maintenance on Coker 8-1; and iii) fewer shipments of synthetic crude as a result of outages on the Pembina pipeline. The higher production rates were partially offset by unscheduled maintenance on the Vacuum Distillation Unit in the third quarter.

Commodity Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Crude Oil				
Dated Brent (Brent) (US$/bbl)	68.27	114.78	57.16	111.02
West Texas Intermediate (WTI) (US$/bbl)	68.30	117.98	57.00	113.29
Benchmark Differentials [1] (US$/bbl)				
Heavy Oil	10.39	17.74	9.10	20.55
Mars	1.90	5.38	1.17	6.42
Masila	(0.54)	5.01	0.15	3.75
Realized Prices from Producing Assets (Cdn$/bbl)				
United Kingdom	73.15	114.89	63.78	108.21
Yemen	76.31	115.92	65.22	110.46
Canada	59.88	97.91	50.10	85.69
United States	72.27	122.46	61.60	110.29
Other Countries	70.49	120.11	55.89	108.03
Syncrude	74.54	126.56	67.26	120.12
Corporate Average (Cdn$/bbl)	72.95	115.56	63.15	108.36
Natural Gas				
New York Mercantile Exchange (US$/mmbtu)	3.44	8.95	3.91	9.73
AECO (Cdn$/mcf)	2.87	8.76	3.89	8.13
Realized Prices from Producing Assets (Cdn$/mcf)				
United Kingdom	2.64	7.53	4.04	7.11
Canada	2.85	8.00	3.67	8.33
United States	3.56	10.14	4.59	10.28
Corporate Average (Cdn$/mcf)	3.04	8.65	3.96	9.03
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	63.00	106.22	56.89	99.64
Average Foreign Exchange Rate – Canadian to US Dollar	0.9108	0.9599	0.8546	0.9817

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

Lower commodity prices reduced quarterly net income by $687 million

Crude oil prices strengthened 15% during the quarter with Brent, which the majority of our production is priced off, averaging US$68.27/bbl and WTI averaging US$68.30/bbl. However, crude prices were approximately 42% lower compared to the record prices in the third quarter last year. The impact of lower commodity prices from last year was mitigated somewhat by the strengthening US dollar. Our realized crude oil sales price averaged $72.95/bbl, 37% lower than the third quarter of 2008.

Natural gas prices continued to struggle during the quarter with NYMEX averaging US$3.44/mmbtu and AECO averaging $2.87/mcf. This was a decline of 10% and 17%, respectively from the previous quarter, and approximately 66% lower than last year. As most of our natural gas sales are priced based on NYMEX and AECO benchmark prices, these declines resulted in a realized average gas sales price of $3.04/mcf, 19% lower than the previous quarter and 65% lower than last year.

Compared to the third quarter of 2008, the US dollar strengthened against the Canadian dollar. As a result, our realized crude oil price increased by $3.73/bbl, while our realized natural gas price increased by $0.16/mcf. This increased our net sales by approximately $50 million. Compared to the previous quarter however, the US dollar weakened against the Canadian dollar, decreasing our net sales by approximately $62 million. This reduced our realized crude oil and natural gas prices by $4.57/bbl and $0.19/mcf, respectively.

CRUDE OIL REFERENCE PRICES

During the third quarter, WTI traded from a low of US$59.52/bbl to a high of US$74.37/bbl. The main drivers supporting recent increases in crude oil prices included a continuing rally in US equity markets, positive investment flows into commodity markets due to the weakening US dollar and a more optimistic outlook on the global economic recovery.

However, near-term supply/demand fundamentals have not improved as global inventory levels and spare capacity remain high and demand has been slow to recover. Economic indicators continue to be mixed and uncertainty remains about the shape of the recovery over the next few years. Most countries are expected to show positive third quarter growth, consumer confidence has increased, and industrial surveys show improvement. However, unemployment is expected to remain high, US mortgage default rates have continued to increase, and questions remain concerning the sustainability of future economic growth without support from government spending.

Geopolitical events during the quarter such as concerns over Iran's nuclear enrichment program, ongoing unrest in Iraq and Afghanistan and requests for stronger regulation of energy markets and futures trading appear to have had little impact on price.

CRUDE OIL DIFFERENTIALS

The heavy oil differential continued to be narrower than historic levels due to increasing North American heavy oil refinery capacity, cuts in medium crude oil production by OPEC, strong fuel oil prices and lower heavy oil supply from Mexico. Line-fill requirements for the Keystone pipeline in North America are expected to offset the impact of colder winter weather which has historically caused differentials to widen in the winter season.

The Brent/WTI differential was volatile during the quarter. Brent traded at a premium to WTI early in the third quarter due to depressed WTI pricing caused by high inventory levels at Cushing and reduced supply in the North Sea due to maintenance downtime. However, as US inventories decreased through the quarter, the differential reverted to a discount to WTI.

Higher Cushing inventory levels also contributed to the narrower Masila differential. The Masila price strengthened relative to Brent, reflecting strong demand from China and other Asian countries.

The Mars differential was narrow during July and August but widened in September as inventories fell at Cushing.

NATURAL GAS REFERENCE PRICES

NYMEX natural gas prices were volatile during the quarter. Relative to last year, low prices were driven by declines in industrial and power demand and high inventory levels as natural gas producers have been slow to respond to lower prices by reducing supply. Despite the fundamentals, prices strengthened during the quarter to a high of US$5/mmbtu at the end of September. Continuing weak gas prices are forecasted as strong supply additions are expected from shale gas, tight gas and new LNG volumes from Russia and the Middle East.

Operating Expenses

	Three Months Ended September 30		Nine Months Ended September 30	
(Cdn$/boe)	**2009**	**2008**	**2009**	**2008**
Operating expenses based on our production before royalties [1]				
Conventional Oil and Gas	11.56	8.75	9.41	8.38
Synthetic Crude Oil				
Syncrude	29.50	32.40	39.26	37.22
Average Oil and Gas	13.60	10.90	11.97	10.70
Operating expenses based on our production after royalties				
Conventional Oil and Gas	13.45	10.38	10.90	10.09
Synthetic Crude Oil				
Syncrude	33.19	39.23	42.67	44.01
Average Oil and Gas	15.76	12.96	13.79	12.87

[1] Operating expenses 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.

Lower operating expenses increased net income for the quarter by $3 million

Our corporate average oil and gas operating cost increased $2.70/boe compared to the third quarter of 2008. Changes in production mix due to various temporary shutdowns for maintenance during the quarter resulted in lower production volumes. However, we continued to incur fixed operating costs at the same time. The lower volumes and fixed operating costs increased our per unit costs by $1.62/boe. The stronger US dollar resulted in higher US-dollar denominated operating costs, increasing our corporate average by $0.60/boe.

In the UK North Sea, absolute operating costs at Buzzard decreased compared with the same period last year due to previously announced downtime. However, per unit operating costs were higher as additional costs were incurred for maintenance during the shut down, combined with lower production volumes. This increased our corporate average by $0.56/boe. At Scott/Telford, we similarly incurred higher operating costs per barrel due to planned maintenance downtime. This, combined

with the start up of Ettrick where operating costs per barrel are higher than our corporate average, increased our corporate average by $0.22/boe.

In Yemen, we continue to incur costs to maintain existing well productivity to maximize reserve recoveries and slow the natural decline of the field. These costs, combined with production declines, increased our corporate average operating cost by $0.73/boe. In the US Gulf of Mexico, lower repair and maintenance costs and higher volumes reduced the consolidated average unit cost by $0.59/boe.

Canada reduced our corporate average by $0.11/boe from lower utility and downhole workover costs, while lower natural gas prices and maintenance costs at Syncrude decreased our corporate average by $0.33/boe.

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Cdn$/boe)	**2009**	**2008**	**2009**	**2008**
DD&A based on our production before royalties [1]				
Conventional Oil and Gas	19.14	16.08	18.71	15.05
Synthetic Crude Oil				
Syncrude	6.12	6.10	6.29	6.47
Average Oil and Gas	17.66	15.17	17.64	14.36
DD&A based on our production after royalties				
Conventional Oil and Gas	22.26	19.08	21.67	18.13
Synthetic Crude Oil				
Syncrude	6.88	7.38	6.83	7.65
Average Oil and Gas	20.46	18.03	20.32	17.27

[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.

Lower oil and gas DD&A increased net income for the quarter by $38 million

Our corporate average DD&A cost per barrel increased $2.49/boe over last year. However, lower production as a result of maintenance and turnaround activity during the quarter reduced our absolute oil and gas DD&A expense by 11%. The stronger US dollar increased our corporate average by $1.09/boe as depletion of our international and US assets is denominated in US dollars.

Our production mix was impacted as a result of lower production caused by maintenance downtime in the UK North Sea and natural declines in Yemen. This change in production mix increased our overall corporate average by $0.51/boe.

In the UK North Sea, our Buzzard depletion rate decreased from the same period last year as successful development drilling increased our proved reserve estimates at the end of 2008. This lower depletion rate reduced our corporate average by $0.06/boe. Elsewhere in the UK, higher depletion rates at Ettrick and Scott/Telford increased our corporate average by $1.18/boe. The depletion rate at our mature Scott/Telford fields increased compared to last year as a result of downward price-related reserve revisions at the end of 2008.

Lower depletion rates in Yemen, due to lower capital expenditures from drilling fewer development wells and higher reserve estimates, reduced our corporate average by $1.23/boe. In the Gulf of Mexico, higher estimates for future abandonment costs and downward price-related reserve revisions at the end of 2008 resulted in higher depletion rates, increasing our corporate average rate by $0.31/boe.

Canadian depletion increased our corporate average by $0.69/boe. Depletion rates at our heavy oil properties were also up due to downward price-related revisions to our proved reserves at the end of 2008. This was partially offset by lower depletion rates at our CBM properties where additional proved reserves were recognized through improved recovery rates.

Exploration Expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Seismic	16	38	59	72
Unsuccessful Drilling	51	50	78	101
Other	22	24	82	72
Total Exploration Expense	89	112	219	245
New Growth Exploration	129	126	459	446
Geological and Geophysical Costs	16	38	59	72
Total Exploration Expenditures	145	164	518	518
Exploration Expense as a % of Exploration Expenditures	61%	68%	42%	47%

Lower exploration expense increased net income for the quarter by $23 million

Exploration expenditures were $19 million lower than the same period last year primarily due to lower seismic acquisition costs. During the quarter, we focused on: i) furthering our appraisal of the Golden Eagle area in the UK North Sea; ii) investing in our shale gas exploration program at Dilly Creek; and iii) advancing our deep water exploration program in the Eastern Gulf of Mexico.

We have significant exploration success in the Golden Eagle area, which includes our 34% operated interest in Golden Eagle and Hobby, and our 46% operated interest in Pink. We have drilled three exploration and ten appraisal wells, with additional appraisal wells due in the fourth quarter. We are evaluating development options as we move towards project sanction.

We continue to make significant progress on our shale gas project in the Dilly Creek area of the Horn River basin in north-east British Columbia, where we have approximately 88,000 acres with a 100% working interest. During the quarter, we concluded a three-well fracing and completion program and now have five shale gas wells on stream. Substantial cost savings and productivity improvements were realized with this drilling and completion program.

In the Eastern Gulf of Mexico, we are currently drilling an exploratory well at Appomattox, about six miles west of our discovery at Vicksburg. The well was spud in September and drilling operations are ongoing. Elsewhere, we continue to evaluate drilling results from our Owowo South B-1 well, 20 kilometers northeast of the Usan field, offshore Nigeria.

Exploration expense was $23 million lower than the same period last year, mainly related to lower seismic acquisition costs. Our exploration expense includes costs to acquire seismic data in the Gulf of Mexico and North Sea.

Unsuccessful drilling expense during the quarter includes CBM drilling costs in Canada and an unsuccessful well in the Eastern Gulf of Mexico. We expensed costs of $20 million related to our CBM exploration activities in central Alberta on those properties where we have no future development plans. Our Antietam well in the Eastern Gulf of Mexico was drilled to a depth of 23,000 feet. The well encountered thick good quality sand, but was wet. The well was subsequently plugged and abandoned, and we expensed drilling costs of $31 million. In the third quarter of 2008, exploration expense included unsuccessful drilling costs of $26 million related to our Fredericksburg well in the US Gulf of Mexico and $6 million for our Yeoman well in the UK North Sea.

ENERGY MARKETING

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Physical Sales [1]	9,711	16,479	29,719	48,987
Physical Purchases [1]	(9,605)	(16,255)	(29,011)	(48,077)
Net Financial Transactions [2]	117	239	(111)	(365)
Change in Fair Market Value of Inventory	(35)	(314)	79	(164)
Marketing Revenue	188	149	676	381
Transportation Expense	(145)	(197)	(473)	(536)
Other	4	7	8	19
Net Marketing Revenue	47	(41)	211	(136)
Contribution to Net Marketing Revenue by Region				
North America	33	(53)	192	(131)
Asia	4	2	22	10
Europe	10	10	(3)	(15)
Net Marketing Revenue	47	(41)	211	(136)
DD&A	(14)	(4)	(21)	(11)
General and Administrative	(19)	4	(68)	(63)
Allowance for Doubtful Receivables	4	(38)	4	(38)
Marketing Contribution to Income before Income Taxes	18	(79)	126	(248)
North America				
Natural Gas				
Physical Sales Volumes [3] (bcf/d)	4.9	7.0	4.9	7.0
Transportation Capacity (bcf/d)	1.5	2.1	1.5	2.1
Storage Capacity (bcf)	32.5	49.3	32.5	49.3
Financial Volumes [4] (bcf/d)	8.7	12.5	11.4	19.2
Crude Oil				
Physical Sales Volumes [3] (mbbls/d)	802	645	837	649
Storage Capacity (mmbbls)	3.1	3.2	3.1	3.2
Financial Volumes [4] (mbbls/d)	699	1,454	796	1,429
Power				
Physical Sales Volumes [3] (GWh/d)	14	5	9	5
Generation Capacity (MW)	87	87	87	87
Asia				
Physical Sales Volumes [3] (mbbls/d)	93	82	97	103
Financial Volumes [4] (mbbls/d)	420	365	425	324
Europe				
Natural Gas				
Physical Sales Volumes [3] (bcf/d)	1.2	1.1	1.2	1.2
Storage Capacity (bcf)	3.1	3.8	3.1	3.8
Crude Oil				
Financial Volumes [4] (mbbls/d)	261	216	340	970
Power				
Physical Sales Volumes [3] (GWh/d)	6	6	6	5
Value-at-Risk				
Quarter-end	13	27	13	27
High	15	33	24	40
Low	11	19	11	19
Average	12	29	16	31

[1] Marketing's physical sales, physical purchases and net financial transactions are reported within marketing revenue as detailed in the notes to the unaudited consolidated financial statements.

[2] Net financial transactions include all gains and losses on financial derivatives and the unrealized portion of gains and losses on physical purchase and sale contracts.

[3] Excludes inter-segment transactions. Physical volumes represent amounts delivered during the quarter.

[4] Financial volumes represent amounts largely acquired to economically hedge physical transactions during the quarter.

Higher contribution from Energy Marketing increased net income by $130 million

During the quarter, we initiated a strategic review of our energy marketing natural gas and power businesses. This review continues to align our marketing activities with our upstream oil and gas businesses. The review may include the sale of all or part of these businesses and is expected to continue into 2010. Data rooms are ready and numerous parties have expressed interest.

In the interim, our energy marketing team continues to focus on optimizing our physical marketing business with all groups contributing positive results in the quarter. In particular, positive returns generated by active asset optimization by the natural gas team more than offset the impact of narrowing transportation spreads. The global crude oil team continued to profit from the contango crude oil forward curve.

Our energy marketing results in 2009 are significantly improved over 2008. Last year, we incurred losses in our natural gas business, due to narrowing spreads between supply regions and consuming markets, and on certain physical basis contracts and losses on contracts used to protect the value of some of our physical capacity contracts. The losses were offset somewhat by gains from blending crude oil. Late in the year, the team began exiting positions and working to reduce trading levels and the overall size of our North American gas business.

Our results last year also included a $38 million provision for our exposure to Lehman Brothers who filed for bankruptcy protection in September 2008.

Our third quarter results were consistent relative to the second quarter. This was due to improved results from the global crude oil teams who profited from the contango curve offset by lower income from the North America gas team. The gas team recognized mark-to-market losses on derivatives that protect our storage and inventory assets, and losses on the value of inventory associated with lower prompt gas prices. We expect to see some recovery in the fourth quarter in the value of our physical assets as we move towards higher seasonal prices for winter.

Results from our energy 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	
	2009	**2008**	**2009**	**2008**
Trading Activities (Physical and related Financial)	43	(49)	201	(157)
Non-Trading Activities	4	8	10	21
Total Net Marketing Revenue	47	(41)	211	(136)

Trading Activities

In energy marketing, we enter into contracts to purchase and sell crude oil and natural gas as well as storage and transportation contracts to capture time and location differences. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all financial and 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, storage and sales 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

Our processes for estimating and classifying the fair value of our derivative contracts are consistent with those in place at December 31, 2008.

At September 30, 2009, the fair value of our derivative contracts in our energy marketing trading activities was a net liability of $7 million. These derivatives are used to 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.

	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Level 1 – Actively Quoted Markets	(106)	(54)	(20)	–	(180)
Level 2 – Based on Other Observable Pricing Inputs	82	53	9	7	151
Level 3 – Based on Unobservable Pricing Inputs	4	17	1	–	22
Total	(20)	16	(10)	7	(7)

Changes in Fair Value of Derivative Contracts

	Total
Fair Value at December 31, 2008	63
Change in Fair Value of Contracts	116
Net Losses (Gains) on Contracts Closed	(186)
Changes in Valuation Techniques and Assumptions [1]	–
Fair Value at September 30, 2009	(7)

[1] Our valuation methodology has been applied consistently in each period.

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 1.3 years. Those maturing beyond one year primarily relate to North American natural gas positions.

CHEMICALS

Higher Chemicals contribution increased net income by $24 million

Third quarter chemicals revenue experienced a decline in both chlor-alkali and chlorate sales in North America and Brazil. North America chlorate revenue decreased 4% from the same period last year, as a 12% reduction in sales volumes attributable to the global economic downturn was only partially offset by higher prices. North America chlor-alkali revenue decreased 11% over the same period due to a combination of lower volumes and weaker caustic prices. In Brazil, lower prices and sales volumes reduced chlorate and chlor-alkali revenues by 10% and 42%, respectively. Chlor-alkali revenues in Brazil were lower as a result of fewer sales of purchased product as this activity generates no gross margin.

Chemicals contribution increased from the same period last year as the stronger Canadian dollar at September 30, 2009 generated unrealized foreign exchange gains of $24 million on the Canexus US-dollar denominated debt. This was higher than the third quarter of 2008 when our chemicals operations recognized foreign exchange translation losses of $12 million.

CORPORATE EXPENSES

General and Administrative (G&A)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
General and Administrative Expense before Stock-Based Compensation	118	100	329	286
Stock-Based Compensation [1]	(5)	(408)	51	(121)
Total General and Administrative Expense	113	(308)	380	165

[1] Includes cash and non-cash expenses related to our tandem option and stock appreciation rights plans.

Higher G&A costs decreased net income by $421 million

Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. During the quarter, our share price decreased 4% and we reversed approximately $19 million of non-cash stock-based compensation expense that we had previously recognized. In the same period last year, our share price was lower by 39% resulting in a $410 million reversal of previously recognized stock-based compensation expense. Cash payments made in connection with our stock-based compensation programs during the three and nine month periods ended September 30, 2009 were $14 million and $28 million respectively (2008 – $2 million and $89 million, respectively).

Interest

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Interest	100	80	286	235
Less: Capitalized	(16)	(64)	(60)	(176)
Net Interest Expense	84	16	226	59
Effective Interest Rate	5.2%	6.1%	4.9%	4.6%

Higher net interest expense reduced net income by $68 million

Our financing costs increased $20 million from the third quarter of 2008. In July 2009, we issued US$1 billion of long-term notes and additional interest in the quarter related to this debt was $13 million. In addition, the stronger US dollar increased our interest expense by $6 million. Interest expense on our term credit facilities was slightly higher than the third quarter of 2008, as additional borrowings were partially offset by lower interest rates on floating rate debt.

Capitalized interest on our Long Lake Project was $51 million lower than the previous year as construction of the facilities was completed earlier in the year. We also ceased capitalizing interest on Ettrick during the quarter. These decreases were partially offset by capitalizing additional interest on construction of the fourth platform at Buzzard and on our major development at Usan, offshore West Africa.

Income Taxes

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Current	190	(26)	514	817
Future	(81)	645	(397)	583
Total Provision for Income Taxes	109	619	117	1,400

Lower taxes increased net income by $510 million

Our provision for income taxes decreased $510 million as compared to the third quarter of 2008 due to lower commodity prices and production in 2009 and a significant reversal of stock-based compensation expense in 2008. In the third quarter of 2008, we completed an internal reorganization and financing of our North Sea assets which provided us with an additional one-time current tax reduction. Our income tax provision includes current taxes in the UK, Yemen, Norway, Colombia and the US.

Other

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Decrease in Fair Value of Crude Oil Put Options	(23)	9	(218)	(1)

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 Dated Brent floor price of US$60/bbl, 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. During the third quarter of 2008, Lehman Brothers, one of the put option counterparties, filed for bankruptcy protection impacting 25,000 bbls/d of our 2009 put options. The carrying value of these put options has been reduced to nil. At September 30, 2009, the remaining options had a fair value of $12 million, $218 million lower than the end of 2008.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

	September 30 **2009**	December 31 **2008**
Net Debt [1]		
Bank Debt	1,847	1,448
Public Senior Notes	5,064	4,582
Total Senior Debt	6,911	6,030
Subordinated Debt	518	548
Total Debt	7,429	6,578
Less: Cash and Cash Equivalents	(1,897)	(2,003)
Total Net Debt	5,532	4,575
Shareholders' Equity	7,401	7,191

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

During the quarter, we issued US$1 billion of senior notes with US$300 million maturing in 10 years and US$700 million maturing in 30 years. The issuance of the new debt increased the average term-to-maturity of our debt to 17 years. Proceeds from the debt issue were used to repay a portion of our outstanding term credit facilities as well as for general corporate purposes.

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:

	Three Months Ended September 30 **2009**	Nine Months Ended September 30 **2009**
Capital Investment	655	2,119
Acquisition of Additional Working Interest at Long Lake	–	755
Cash Flow from Operating Activities [1]	(461)	(1,359)
Deficiency	194	1,515
Dividends on Common Shares	26	78
Issue of Common Shares	(12)	(42)
Changes in Restricted Cash	(93)	154
Foreign Exchange Translation of US-dollar Debt and Cash	(470)	(797)
Other	(2)	49
Increase (Decrease) in Net Debt	(357)	957

[1] Includes changes in non-cash working capital. For the three months ended September 30, $113 million was included as a source of cash flow and for the nine months ended September 30, $193 million was included as a source of cash flow.

Our net debt decreased from June 30, 2009 primarily as a result of the Canadian dollar strengthening relative to the US dollar. This impact was partially offset as our quarterly capital investment exceeded our cash flow from operating activities by $194 million. Our available liquidity at September 30, 2009 was approximately US$3.3 billion, comprised of cash on hand and undrawn credit facilities. Operating cash flows in the oil and gas industry can be volatile as short-term commodity prices are driven by existing supply and demand fundamentals and market volatility. We invest through the lows of the current commodity market to create future growth and value for our shareholders for the long-term. Changes in our non-cash working capital can vary between quarters as our energy marketing net working capital position fluctuates depending on timing of settlement of outstanding positions, the movement in commodity prices and inventory cycles.

Change in Working Capital

	September 30 **2009**	December 31 **2008**	Increase/ (Decrease)
Cash and Cash Equivalents	1,897	2,003	(106)
Restricted Cash	216	103	113
Accounts Receivable	2,877	3,163	(286)
Inventories and Supplies	590	484	106
Accounts Payable and Accrued Liabilities	(3,358)	(3,326)	(32)
Other	92	76	16
Net Working Capital	2,314	2,503	

Accounts receivable in our energy marketing group decreased since year end as we reduced our trading activity to focus on supporting our core physical business as a producer/marketer. Commodity inventory increased since 2008 as our trading inventory is carried at fair value and was higher than year-end as a result of stronger crude oil prices.

At September 30, 2009, our restricted cash consists of margin deposits of $216 million (December 31, 2008 – $103 million) related to exchange-traded derivative financial contracts used by our energy marketing group to hedge physical commodities, and storage, transportation and customer sales contracts. We are required to maintain margin for net out-of-the-money derivative financial contracts. The increase in margin primarily relates to derivative financial contracts protecting our natural gas positions. Our physical positions gained in value in a declining gas price environment while the derivative financial contracts protecting these positions declined in value. Additional margin was required to cover the increase in the net out-of-the-money derivative financial contracts.

Outlook for Remainder of 2009

Following the completion of turnaround and maintenance activity in the third quarter and the start up of new production, we are currently producing approximately 275,000 boe/d. With production ramping up at Ettrick, Longhorn and Long Lake, we expect fourth quarter production volumes will remain strong.

Our future liquidity and ability to fund capital requirements generally depends upon operating cash flows, existing working capital, unused committed credit facilities, and our ability to access debt and equity markets. 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 85% of our current 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 above US$60/bbl is projected to increase or decrease our cash flow from operating activities, after cash taxes, by approximately $13 million for the remainder of 2009. Our exposure to a $0.01 change in the US to Canadian dollar exchange rate is projected to increase or decrease our cash flow by approximately $9 million for the remainder of 2009. While commodity prices can fluctuate significantly in the short term, we believe that over the longer term, commodity prices will continue to strengthen as a result of growth in world demand and delays or shortages in supply growth. We believe that our existing liquidity, balance sheet capacity and capital investment flexibility provides us with the ability to fund our obligations during periods of lower commodity prices.

We have incurred approximately 80% of our 2009 planned capital expenditures to date and also acquired an additional 15% working interest in Long Lake. During the quarter, our capital was concentrated on developing our Usan project offshore Nigeria, appraising the Golden Eagle/Hobby area, advancing work on the fourth platform at Buzzard, bringing our Ettrick and Longhorn developments on stream, and on progressing our Horn River shale gas play in northeastern British Columbia.

During the first nine months of 2009, lower commodity prices reduced our cash flow from operating activities relative to the same period last year. Over the same period, we have invested approximately $2.1 billion in capital projects and another $755 million to acquire an additional 15% in the Long Lake Project. As our capital expenditures exceeded our cash flow from operating activities, we drew upon our available liquidity and issued US$1 billion of long-term debt. We currently have approximately $1.9 billion of cash and cash equivalents on hand and as well as significant undrawn committed credit facilities available. At September 30, 2009, we had unsecured term credit facilities of US$3.1 billion in place that are available until 2012, of which US$1.5 billion was drawn and US$398 million was used to support outstanding letters of credit. We also have approximately $493 million of undrawn, uncommitted, unsecured credit facilities, of which $119 million was used to support outstanding letters of credit. The average length-to-maturity of our public debt is approximately 17 years.

In the third quarter, our board of directors declared a quarterly common share dividend of $0.05 per share.

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 2008 Form 10-K. There have been no 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 2008 Form 10-K. There have been no significant developments since year-end.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

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 have set up a project team to manage this transition and to ensure successful implementation within the required timeframe.

We are currently assessing the impact of adopting IFRS on our results of operations, financial position, disclosures and financial systems. We have completed our diagnostic phase and are in the midst of the implementation phase. To date, we determined that the majority of our existing oil and gas accounting policies are acceptable under current IFRS standards. IFRS does not prescribe specific accounting guidance for extractive industries such as oil and gas, other than for costs associated with the exploration and evaluation phase. Our detailed analysis has identified differences that will impact certain aspects of our accounting for property, plant and equipment, asset retirement obligations, and long-term asset impairments. We expect to complete the implementation phase early in 2010. We are also currently evaluating the impact of exemptions and exceptions available to first-time IFRS adopters which give relief from retrospective application of IFRS. We continue to monitor changes to IFRS standards prior to adoption in 2011. Training sessions have been ongoing throughout the company and will continue into 2010.

At this time, we cannot quantify the impact that the adoption of IFRS will have on our future results of operations or future financial position. Additional disclosure of the key elements of our plan and progress on the project will be provided as we move towards the changeover date.

US Pronouncements

In December 2008, the Financial Accounting Standards Board (FASB) issued *Employers Disclosures about Postretirement Benefit Plan Assets.* This position provides guidance on disclosures about plan assets of a defined benefit pension plan or other postretirement plans. This position is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In June 2009, FASB issued *Amendments to Consolidation of Variable Interest Entities.* It retains the scope of the previous guidance with the addition of entities previously considered qualifying special-purpose entities and eliminates the previous quantitative approach for a qualitative analysis in determining whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The Statement is further amended to require ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity and requires enhanced disclosures about an enterprise's involvement in a variable interest entity. The Statement is effective at the beginning the first annual reporting period after November 15, 2009. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

EQUITY SECURITY REPURCHASES

During the quarter, we made no purchases of our own equity securities.

SUMMARY OF QUARTERLY RESULTS

	2007	2008				2009		
(Cdn$ millions, except per share amounts)	Dec	Mar	Jun	Sep	Dec	Mar	Jun	Sep
Net Sales	1,598	1,870	2,071	2,213	1,270	1,048	1,200	1,097
Net Income (Loss)	194	630	380	886	(181)	135	20	122
Earnings (Loss) Per Common Share ($/share)								
Basic	0.37	1.19	0.72	1.68	(0.35)	0.26	0.04	0.23
Diluted	0.36	1.17	0.70	1.66	(0.35)	0.26	0.04	0.23

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*, 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 acquisitions or 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 sources of liquidity, 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;
- future foreign currency exchange rates;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed, will come on-stream or reach expected operating capacity; 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;

- ultimate effectiveness of design modification to facilities;
- 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 environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings;
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and
- other factors, many of which are beyond our control.

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* and in Item 7A of our 2008 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	
	2009	**2008**	**2009**	**2008**
Revenues and Other Income				
Net Sales	1,097	2,213	3,345	6,154
Marketing and Other (Note 14)	296	131	635	387
	1,393	2,344	3,980	6,541
Expenses				
Operating	321	341	946	998
Depreciation, Depletion, Amortization and Impairment	358	386	1,180	1,084
Transportation and Other	185	291	618	691
General and Administrative	113	(308)	380	165
Exploration	89	112	219	245
Interest (Note 9)	84	16	226	59
	1,150	838	3,569	3,242
Income before Provision for Income Taxes	243	1,506	411	3,299
Provision for (Recovery of) Income Taxes				
Current	190	(26)	514	817
Future	(81)	645	(397)	583
	109	619	117	1,400
Net Income	134	887	294	1,899
Less: Net Income Attributable to Canexus Non-Controlling Interests	(12)	(1)	(17)	(3)
Net Income Attributable to Nexen Inc.	122	886	277	1,896
Earnings Per Common Share ($/share) (Note 15)				
Basic	0.23	1.68	0.53	3.59
Diluted	0.23	1.66	0.53	3.53

See accompanying notes to the Unaudited Consolidated Financial Statements.

Nexen Inc.
Unaudited Consolidated Balance Sheet

(Cdn$ millions, except share amounts)	September 30 **2009**	December 31 **2008**
Assets		
Current Assets		
Cash and Cash Equivalents	1,897	2,003
Restricted Cash (Note 7)	216	103
Accounts Receivable (Note 2)	2,877	3,163
Inventories and Supplies (Note 3)	590	484
Other	199	169
Total Current Assets	5,779	5,922
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,452 (December 31, 2008 – $10,393)	15,642	14,922
Goodwill	346	390
Future Income Tax Assets	916	351
Deferred Charges and Other Assets (Note 5)	386	570
Total Assets	23,069	22,155
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 8)	3,358	3,326
Accrued Interest Payable	81	67
Dividends Payable	26	26
Total Current Liabilities	3,465	3,419
Long-Term Debt (Note 9)	7,429	6,578
Future Income Tax Liabilities	2,698	2,619
Asset Retirement Obligations (Note 11)	992	1,024
Deferred Credits and Other Liabilities (Note 12)	1,084	1,324
Shareholders' Equity (Note 13)		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2009 – 521,846,559 shares		
2008 – 519,448,590 shares	1,025	981
Contributed Surplus	1	2
Retained Earnings	6,489	6,290
Accumulated Other Comprehensive Loss	(183)	(134)
Total Nexen Inc. Shareholders' Equity	7,332	7,139
Canexus Non-Controlling Interests	69	52
Total Shareholders' Equity	7,401	7,191
Commitments, Contingencies and Guarantees (Note 16)		
Total Liabilities and Shareholders' Equity	23,069	22,155

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	
	2009	**2008**	**2009**	**2008**
Operating Activities				
Net Income	134	887	294	1,899
Charges and Credits to Income not Involving Cash (Note 17)	174	692	887	1,544
Exploration Expense	89	112	219	245
Changes in Non-Cash Working Capital (Note 17)	113	(840)	193	(468)
Other	(49)	117	(234)	79
	461	968	1,359	3,299
Financing Activities				
Proceeds from Long-Term Notes	1,081	–	1,081	–
Proceeds from (Repayment of) Term Credit Facilities, Net	(915)	1,031	728	803
Proceeds from (Repayment of) Canexus Term Credit Facilities, Net	(4)	(9)	48	(19)
Proceeds from Canexus Debentures	46	–	46	–
Proceeds from Canexus Notes	–	–	–	51
Repayment of Medium-Term Notes	–	–	–	(125)
Repayment of Short-Term Borrowings	(1)	(4)	(1)	(4)
Dividends on Common Shares	(26)	(26)	(78)	(66)
Distributions Paid to Canexus Non-Controlling Interests	(4)	(4)	(11)	(11)
Issue of Common Shares and Exercise of Tandem Options for Shares	12	8	42	48
Repurchase of Common Shares for Cancellation	–	(300)	–	(300)
Changes in Non-Cash Working Capital (Note 17)	–	10	–	10
Other	(18)	2	(19)	–
	171	708	1,836	387
Investing Activities				
Capital Expenditures				
Exploration and Development	(586)	(689)	(1,921)	(2,064)
Proved Property Acquisitions	–	–	(755)	(2)
Energy Marketing, Chemicals, Corporate and Other	(69)	(36)	(198)	(83)
Proceeds on Disposition of Assets	2	–	17	–
Changes in Restricted Cash	93	196	(154)	143
Changes in Non-Cash Working Capital (Note 17)	14	(66)	(41)	(120)
Other	(15)	36	(16)	(61)
	(561)	(559)	(3,068)	(2,187)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(148)	41	(233)	67
Increase (Decrease) in Cash and Cash Equivalents	(77)	1,158	(106)	1,566
Cash and Cash Equivalents – Beginning of Period	1,974	614	2,003	206
Cash and Cash Equivalents – End of Period [1]	1,897	1,772	1,897	1,772

[1] Cash and cash equivalents at September 30, 2009 consist of cash of $376 million and short-term investments of $1,521 million (September 30, 2008 – cash of $26 million and short-term investments of $1,746 million).

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	
	2009	**2008**	**2009**	**2008**
Common Shares, Beginning of Period	1,011	972	981	917
Issue of Common Shares	8	8	37	32
Exercise of Tandem Options for Shares	4	–	5	16
Accrued Liability Relating to Tandem Options Exercised for Common Shares	2	1	2	16
Repurchased Under Normal Course Issuer Bid	–	(18)	–	(18)
Balance at End of Period	1,025	963	1,025	963
Contributed Surplus, Beginning of Period	2	2	2	3
Exercise of Tandem Options	(1)	–	(1)	(1)
Balance at End of Period	1	2	1	2
Retained Earnings, Beginning of Period	6,393	5,953	6,290	4,983
Net Income Attributable to Nexen Inc.	122	886	277	1,896
Dividends on Common Shares (Note 13)	(26)	(26)	(78)	(66)
Repurchase of Common Shares for Cancellation	–	(282)	–	(282)
Balance at End of Period	6,489	6,531	6,489	6,531
Accumulated Other Comprehensive Loss, Beginning of Period	(157)	(274)	(134)	(293)
Other Comprehensive Income (Loss)	(26)	41	(49)	60
Balance at End of Period	(183)	(233)	(183)	(233)
Canexus Non-Controlling Interests, Beginning of Period	54	62	52	67
Net Income Attributable to Non-Controlling Interests	15	1	24	3
Distributions Declared to Non-Controlling Interests	(5)	(5)	(14)	(13)
Issue of Partnership Units to Non-Controlling Interests under Distribution Reinvestment Plan	1	1	3	2
Estimated Fair Value of Conversion Feature of Convertible Debenture Issue Attributable to Non-Controlling Interests	4	–	4	–
Balance at End of Period	69	59	69	59

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	
	2009	**2008**	**2009**	**2008**
Net Income Attributable to Nexen Inc.	122	886	277	1,896
Other Comprehensive Income (Loss), Net of Income Taxes:				
Foreign Currency Translation Adjustment				
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(408)	221	(693)	365
Net Gains (Losses) on Foreign-Denominated Debt Hedging Self-Sustaining Foreign Operations[1]	384	(180)	646	(305)
Realized Translation Adjustments Recognized in Net Income	(2)	–	(2)	–
Other Comprehensive Income (Loss)	(26)	41	(49)	60
Comprehensive Income Attributable to Nexen Inc.	96	927	228	1,956

[1] Net of income tax expense for the three months ended September 30, 2009 of $55 million (2008 – $26 million recovery) and net of income tax expense for the nine months ended September 30, 2009 of $93 million (2008 – $45 million recovery).

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 19. 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, 2009 and December 31, 2008 and the results of our operations and our cash flows for the three and nine months ended September 30, 2009 and 2008.

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, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy 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, 2009 are not necessarily indicative of the results of operations or cash flows to be expected for the year ending December 31, 2009. As at October 27, 2009, there are no material subsequent events requiring additional disclosure in or amendment to these financial statements.

These Unaudited Consolidated Financial Statements should be read in conjunction with our Audited Consolidated Financial Statements included in our 2008 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 2008 Form 10-K.

Changes in Accounting Policies

Goodwill and Intangible Assets
On January 1, 2009, we retrospectively adopted the Canadian Institute of Chartered Accountants (CICA) Section 3064, *Goodwill and Intangible Assets* issued by the AcSB. This section clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard did not have a material impact on our results of operations or financial position.

Business Combinations
On January 1, 2009, we prospectively adopted CICA Section 1582, *Business Combinations* issued by the AcSB. This section establishes principles and requirements of the acquisition method for business combinations and related disclosures. Adoption of this statement did not have a material impact on our results of operations or financial position.

Consolidated Financial Statements and Non-Controlling Interests
On January 1, 2009, we adopted CICA Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-Controlling Interests* issued by the AcSB. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for non-controlling interests in consolidated financial statements subsequent to a business combination. Adoption of these statements did not have a material impact on our results of operations or financial position. The presentation changes have been included in the Unaudited Consolidated Financial Statements as applicable.

2. ACCOUNTS RECEIVABLE

	September 30 **2009**	December 31 **2008**
Trade		
Energy Marketing	1,489	1,501
Energy Marketing Derivative Contracts (Note 6)	552	755
Oil and Gas	657	639
Chemicals and Other	47	68
	2,745	2,963
Non-Trade	186	270
	2,931	3,233
Allowance for Doubtful Receivables	(54)	(70)
Total	2,877	3,163

3. INVENTORIES AND SUPPLIES

	September 30 **2009**	December 31 **2008**
Finished Products		
Energy Marketing	449	384
Oil and Gas	32	17
Chemicals and Other	11	16
	492	417
Work in Process	8	6
Field Supplies	90	61
Total	590	484

4. SUSPENDED EXPLORATION WELL COSTS

The following table shows the changes in capitalized exploratory well costs during the nine months ended September 30, 2009 and the year ended December 31, 2008, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Suspended exploration well costs are included in property, plant and equipment.

	Nine Months Ended September 30 **2009**	Year Ended December 31 **2008**
Beginning of Period	518	326
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	186	254
Capitalized Exploratory Well Costs Charged to Expense	(32)	(81)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(17)	(29)
Effects of Foreign Exchange Rate Changes	(37)	48
End of Period	618	518

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 **2009**	December 31 **2008**
Capitalized for a Period of One Year or Less	189	239
Capitalized for a Period of Greater than One Year	429	279
Total	618	518
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	11	7

As at September 30, 2009, we have exploratory costs that have been capitalized for more than one year relating to our interests in six exploratory blocks in the North Sea ($178 million), certain coalbed methane and shale gas exploratory activities in Canada ($120 million), two exploratory blocks in the Gulf of Mexico ($112 million), and our interest in an exploratory block offshore Nigeria ($19 million). These costs relate to projects with successful exploration wells for which we have not been able to recognize 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.

5. DEFERRED CHARGES AND OTHER ASSETS

	September 30 **2009**	December 31 **2008**
Crude Oil Put Options and Natural Gas Swaps (Note 6) [1]	–	234
Long-Term Energy Marketing Derivative Contracts (Note 6)	241	217
Long-Term Capital Prepayments	42	61
Asset Retirement Remediation Fund	9	9
Defined Benefit Pension Assets	46	3
Other	48	46
Total	386	570

[1] The crude oil put options were reclassified to other current assets in the first quarter as they settle within 12 months.

6. 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, accrued interest payable, dividends payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying values of our short-term receivables and payables approximate their fair value as the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities, 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, 2009. 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, 2009, the estimated fair value of our long-term debt was $7,531 million (December 31, 2008 – $5,686 million) as compared to the carrying value of $7,429 million (December 31, 2008 – $6,578 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

Derivatives

(a) Derivative contracts related to trading activities

Our energy marketing group engages in various activities including the purchase and sale of physical commodities and the use of financial instruments such as commodity and foreign exchange futures, forwards and swaps to economically hedge exposures and generate revenue. These contracts are accounted for as derivatives and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	September 30 **2009**	December 31 **2008**
Commodity Contracts	537	742
Foreign Exchange Contracts	15	13
Accounts Receivable (Note 2)	552	755
Commodity Contracts	241	213
Foreign Exchange Contracts	–	4
Deferred Charges and Other Assets (Note 5) [1]	241	217
Total Trading Derivative Assets	793	972
Commodity Contracts	516	585
Foreign Exchange Contracts	56	30
Accounts Payable and Accrued Liabilities (Note 8)	572	615
Commodity Contracts	228	248
Foreign Exchange Contracts	–	46
Deferred Credits and Other Liabilities (Note 12) [1]	228	294
Total Trading Derivative Liabilities	800	909
Total Net Trading Derivative Contracts	(7)	63

[1] These derivative contracts settle beyond 12 months and are considered non-current; once settlement is within 12 months, they are included in accounts receivable or accounts payable.

Excluding the impact of netting arrangements, the fair value of derivative instruments is as follows:

	September 30 **2009**
Current Trading Assets	3,608
Non-Current Trading Assets	1,031
Total Trading Derivative Assets	4,639
Current Trading Liabilities	3,628
Non-Current Trading Liabilities	1,018
Total Trading Derivative Liabilities	4,646
Total Net Trading Derivative Contracts	(7)

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. During the three and nine months ended September 30, 2009, the following trading revenues were recognized in marketing and other income:

	Three Months Ended September 30 **2009**	Nine Months Ended September 30 **2009**
Commodity	177	748
Foreign Exchange	11	(72)
Marketing Revenue (Note 14)	188	676

As an energy marketer, we may undertake several transactions during a period to execute a single sale of physical product. Each transaction may be represented by one or more derivative instruments including a physical buy, physical sell, and in many cases, numerous financial instruments for economically hedging and trading purposes. The absolute notional volumes associated with our derivative instrument transactions are as follows:

		Three Months Ended September 30 **2009**	Nine Months Ended September 30 **2009**
Natural Gas	bcf/d	19.3	22.2
Crude Oil	mmbbls/d	3.1	3.6
Power	GWh/d	236.1	231.0
Foreign Exchange	USD millions	742	1,973
Foreign Exchange	Euro millions	48	308

(b) Derivative contracts related to non-trading activities

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

	September 30 **2009**	December 31 **2008**
Accounts Receivable	12	6
Deferred Charges and Other Assets (Note 5) [1]	–	234
Total Non-Trading Derivative Assets	12	240
Accounts Payable and Accrued Liabilities	27	21
Deferred Credits and Other Liabilities [1]	7	26
Total Non-Trading Derivative Liabilities	34	47
Total Net Non-Trading Derivative Contracts [2]	(22)	193

[1] These derivative contracts settle beyond 12 months and are considered non-current.
[2] The net fair value of these derivatives is equal to the gross fair value before consideration of netting arrangements and collateral posted or received with counterparties.

Crude oil put options

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production for $14 million. These options establish an annual average Dated Brent floor price of US$60/bbl on these volumes. In September 2008, Lehman Brothers filed for bankruptcy protection. This impacts approximately 25,000 bbls/d of our 2009 put options and the carrying value of these put options has been reduced to nil. The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third party brokers, which were validated with observable market data to the extent possible. With the rise in Dated Brent oil price since the beginning of the year, the fair value of the crude oil put options decreased. This decrease is included in marketing and other income.

					Change in Fair Value	
	Notional Volumes	Term	Average Floor Price	Fair Value	Three Months Ended September 30 **2009**	Nine Months Ended September 30 **2009**
	(bbls/d)		(US$/bbl)			
Dated Brent Crude Oil Put Options	45,000	2009	60	12	(23)	(218)
Dated Brent Crude Oil Put Options	25,000	2009	60	–	–	–
				12	(23)	(218)

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. The change in fair value of the fixed price natural gas contracts and natural gas swaps is included in marketing and other income.

					Change in Fair Value	
	Notional Volumes	Term	Average Price	Fair Value	Three Months Ended September 30 **2009**	Nine Months Ended September 30 **2009**
	(Gj/d)		($/Gj)			
Fixed-Price Natural Gas Contracts	15,514	2009	2.28	(14)	(2)	7
	15,514	2010	2.28	(5)	4	21
Natural Gas Swaps	15,514	2009	7.60	(13)	3	(19)
	15,514	2010	7.60	(2)	2	(3)
				(34)	7	6

(c) Fair value of derivatives

Our processes for estimating and classifying the fair value of our derivative contracts are consistent with those in place at December 31, 2008. The following table includes our derivatives carried at fair value for our trading and non-trading activities as at September 30, 2009. 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.

Net Derivatives	Level 1	Level 2	Level 3	Total
Trading Derivatives	(180)	151	22	(7)
Non-Trading Derivatives	–	(22)	–	(22)
Total	(180)	129	22	(29)

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the nine months ended September 30, 2009 is provided below:

	Level 3
Beginning of Period	(82)
Realized and Unrealized Gains (Losses)	57
Purchases, Issuances and Settlements	55
Transfers In and/or Out of Level 3	(8)
End of Period	22
Unsettled Gains (Losses) Relating to Instruments Still Held as of September 30, 2009	49

Trading derivatives classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 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.

7. RISK MANAGEMENT

(a) Market risk

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks 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 these market exposures.

The following market risk discussion focuses on the commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial, as substantially all of our debt is fixed rate.

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 and are generally sold at contract or posted prices. Changes in the global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices, while natural gas prices are affected primarily by North American supply and demand fundamentals. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes may also affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

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 also expose us to commodity price risk during the time between when we purchase and sell contracted volumes. We periodically manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on providing services for our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities including crude oil, natural gas, electricity and other commodities in selected regions of the world. We accomplish this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers. In order to manage the commodity and foreign exchange price risks that are generated by this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as foreign currency swaps or forwards.

We also seek to profit from our views on the future movement of energy commodity pricing relationships, primarily between different locations, time periods or product qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions. We may also carry exposures to the absolute change in commodity prices based on our market views or as a consequence of managing our physical and financial positions on a daily basis.

Our risk management activities include prescribed capital limits and the use of tools such as Value-at-Risk (VaR) and stress testing consistent with the methodology used at December 31, 2008. Our period end, high, low and average VaR amounts for the three and nine months ended September 30, 2009 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
Value-at-Risk	**2009**	**2008**	**2009**	**2008**
Period End	13	27	13	27
High	15	33	24	40
Low	11	19	11	19
Average	12	29	16	31

If market shocks occur in 2009 as they did in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

Foreign currency risk

Foreign currency 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 borrowings and long-term debt.

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 cash flows. We designate a portion of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

The foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in accumulated other comprehensive income in shareholders' equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at September 30, 2009 and December 31, 2008 are as follows:

(US$ millions)	September 30 **2009**	December 31 **2008**
Net Investment in Self-Sustaining Foreign Operations	4,272	4,662
Designated US-Dollar Debt	4,272	4,545

For the three and nine month periods ended September 30, 2009, the ineffective portion of our US-dollar debt resulted in a net foreign exchange gain of $78 million and $135 million, respectively ($68 million and $118 million, respectively, net of income tax expense) and is included in marketing and other income. A one cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $43 million, net of income tax, and would increase or decrease our net income by approximately $8 million, net of income tax.

We also have modest exposures to currencies other than the US dollar including a portion of our UK operating expenses, capital spending and future asset retirement obligations which are denominated in British Pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies including Canadian and US dollars, British Pounds and Euros. We may actively manage significant currency exposures using forward contracts and swaps.

(b) Credit risk

Credit risk affects our oil, gas and chemicals operations and trading and non-trading derivative activities is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposure is with counterparties in the energy industry, including integrated oil companies, crude oil refiners and utilities, and are subject to normal industry credit risk. Approximately 74% of our exposure is 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. Our processes to manage this risk are consistent with those in place at December 31, 2008.

At September 30, 2009, only one counterparty individually made up more than 10% of our credit exposure. This counterparty is a major integrated oil company with a strong investment grade credit rating. No other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating.

Credit Rating	September 30 **2009**	December 31 **2008**
A or higher	71%	65%
BBB	22%	29%
Non-Investment Grade	7%	6%
Total	100%	100%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts on non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We provided an allowance of $54 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at September 30, 2009 includes $51 million of cash and $506 million of letters of credit. The cash received reflects customer deposits that are included in 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 become due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due, and to operate 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, 2009, we had approximately $3.2 billion of cash and available committed lines of credit. This includes $1.9 billion of cash and cash equivalents on hand. In addition, we have undrawn term credit facilities of $1.7 billion, of which $427 million was supporting letters of credit at September 30, 2009. These facilities are available until 2012. We also have about $493 million of undrawn, uncommitted credit facilities at September 30, 2009.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at September 30, 2009:

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Long-Term Debt [1]	7,522	–	1,847	590	5,085
Interest on Long-Term Debt [2]	8,340	369	739	712	6,520
Total	15,862	369	2,586	1,302	11,605

[1] Excludes cash and cash equivalents currently available.
[2] Excludes interest on term credit facilities of $3.3 billion and Canexus term credit facilities of $452 million as the amounts drawn on the facilities fluctuate. Based on amounts drawn at September 30, 2009 and current interest rates, we would be required to pay $20 million per year until the outstanding amounts on the term credit facilities are repaid.

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 (Note 6)	800	572	189	39	–
Non-Trading Derivatives (Note 6)	34	27	7	–	–
Total	834	599	196	39	–

The commercial agreements our energy marketing group enter 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 occurs, such as a drop in credit rating. Based on contracts in place and commodity prices at September 30, 2009, we could be required to post collateral of up to $975 million if we were downgraded to non-investment grade. This represents the maximum amount of collateral that we would be required to post assuming a severe event that causes all rating agencies to simultaneously downgrade us and no actions are taken by us to mitigate our exposure. This amount includes trade payables of $686 million and derivative contracts with a fair value of $289 million. All of these obligations are included on our September 30, 2009 balance sheet. In the event of a ratings downgrade, we could monetize our trading inventories and receivables and draw on our existing credit facilities to meet our collateral obligations. Further various actions can be taken, in anticipation of a downgrade that would reduce the maximum amount of collateral we would need to provide.

At September 30, 2009, collateral posted with counterparties includes $14 million of cash and $330 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 $216 million (December 31, 2008 – $103 million), which have been included in restricted cash.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30 **2009**	December 31 **2008**
Energy Marketing	1,437	1,286
Accrued Payables	699	887
Energy Marketing Derivative Contracts (Note 6)	572	615
Income Taxes Payable	209	69
Trade Payables	208	251
Stock-Based Compensation	109	97
Other	124	121
Total	3,358	3,326

9. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	September 30 **2009**	December 31 **2008**
Canexus Term Credit Facilities, due 2011 (US$223 million drawn) (a)	239	223
Term Credit Facilities, due 2012 (US$1.5 billion drawn) (b)	1,608	1,225
Canexus Notes, due 2013 (US$50 million)	54	61
Notes, due 2013 (US$500 million)	536	612
Canexus Convertible Debentures, due 2014 (c)	46	–
Notes, due 2015 (US$250 million)	268	306
Notes, due 2017 (US$250 million)	268	306
Notes, due 2019 (US$300 million) (d)	322	–
Notes, due 2028 (US$200 million)	214	245
Notes, due 2032 (US$500 million)	536	612
Notes, due 2035 (US$790 million)	847	968
Notes, due 2037 (US$1,250 million)	1,340	1,531
Notes, due 2039 (US$700 million) (e)	751	–
Subordinated Debentures, due 2043 (US$460 million)	493	563
	7,522	6,652
Unamortized Debt Issue Costs	(93)	(74)
Total	7,429	6,578

(a) Canexus term credit facilities

Canexus has $452 million (US$422 million) of committed, secured term credit facilities, $431 million (US$402 million) of which is available until 2011, with the balance due 2013. At September 30, 2009, $239 million (US$223 million) was drawn on these facilities (December 31, 2008 – $223 million (US$182 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 of Canexus. The weighted-average interest rate on the Canexus term credit facilities was 2.0% for the three months ended September 30, 2009 (three months ended September 30, 2008 – 4.6%) and 2.3% for the nine months ended September 30, 2009 (nine months ended September 30, 2008 – 4.5%).

(b) Term credit facilities

We have unsecured term credit facilities of $3.3 billion (US$3.1 billion) available until 2012. At September 30, 2009, $1.6 billion (US$1.5 billion) was drawn on these facilities (December 31, 2008 – $1.2 billion (US$1 billion)). 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 0.9% for the three months ended September 30, 2009 (three months ended September 30, 2008 – 3.5%) and 1.0% for the nine months ended September 30, 2009 (nine months ended September 30, 2008 – 3.6%). At September 30, 2009, $427 million (US$398 million) of these facilities were utilized to support outstanding letters of credit (December 31, 2008 – $381 million (US$311 million)).

(c) Canexus convertible debentures

In August 2009, Canexus issued $46 million of convertible unsecured subordinated debentures to non-controlling interests. Interest is payable semi-annually at a rate of 8.00%. These debentures mature on December 31, 2014 and are convertible at the holder's option at any time prior to the close of business on the earlier of i) the maturity date and ii) the business day immediately preceding the date specified by Canexus for redemption of the debentures into trust units. The conversion price is $5.10 per trust unit.

Canexus has the option to redeem the debentures in whole or in part from time to time subject to the satisfaction of certain conditions, after December 31, 2012 but before maturity, at a redemption price equal to the principal amount and unpaid interest. Canexus may elect to satisfy its obligation to pay interest or repay the principal by issuing trust units at market value.

The estimated fair value of the conversion feature of the convertible debentures amounted to $4 million and was included in non-controlling interests, in shareholders' equity. The amount of the convertible debentures allocated to long-term debt is being amortized over the term of the debt using the effective interest rate method.

Concurrent with the issuance, we acquired $40 million of debentures from Canexus with substantially the same terms which allow us to protect against dilution of our ownership interest at our option. These debentures are eliminated on consolidation.

(d) Notes, due 2019

In July 2009, we issued US$300 million of notes. Interest is payable semi-annually at a rate of 6.20%, and the principal is to be repaid in July 2019. We 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 0.40%.

(e) Notes, due 2039

In July 2009, we issued US$700 million of notes. Interest is payable semi-annually at a rate of 7.50%, and the principal is to be repaid in July 2039. We 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 0.45%.

(f) Interest expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Long-Term Debt	96	75	274	220
Other	4	5	12	15
Total	100	80	286	235
Less: Capitalized	(16)	(64)	(60)	(176)
Total	84	16	226	59

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

(g) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $493 million (US$459 million), none of which were drawn at September 30, 2009 (December 31, 2008 – nil). We utilized $119 million (US$111 million) of these facilities to support outstanding letters of credit at September 30, 2009 (December 31, 2008 – $29 million (US$24 million)). Interest is payable at floating rates. The weighted-average interest rate on our short-term borrowings was nil for the three months ended September 30, 2009 (three months ended September 30, 2008 – 3.6%) and 2.1% for the nine months ended September 30, 2009 (nine months ended September 30, 2008 – 3.2%).

10. CAPITAL MANAGEMENT

Our objectives and processes for managing our capital structure are consistent with those in place at December 31, 2008. Our capital consists of shareholders' equity, short-term borrowings, long-term debt and cash and cash equivalents as follows:

	September 30 **2009**	December 31 **2008**
Net Debt [1]		
Long-Term Debt	7,429	6,578
Less: Cash and Cash Equivalents	(1,897)	(2,003)
Total	5,532	4,575
Shareholders' Equity	7,401	7,191

[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 and interest coverage ratios at various commodity prices.

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 that does not have any standard meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by others. We calculate net debt 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, 2009, our net debt to cash flow from operating activities ratio was 2.3 times compared to 1.1 times at December 31, 2008. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility or when we identify

strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio monitors our ability to fund the interest requirements associated with our debt. Our interest coverage was 7.2 times at September 30, 2009 (December 31, 2008 – 15.6 times). Interest coverage is calculated by dividing our twelve-month trailing adjusted EBITDA by interest expense before capitalized interest. Adjusted EBITDA is a non-GAAP measure. The calculation of adjusted EBITDA is set out in the following table and is unlikely to be comparable to similar measures presented by others.

	Twelve Months Ended September 30 **2009**	Year Ended December 31 **2008**
Net Income Attributable to Nexen Inc.	96	1,715
Add:		
Interest Expense	261	94
Provision for Income Taxes	174	1,457
Depreciation, Depletion, Amortization and Impairment	2,110	2,014
Exploration Expense	376	402
Recovery of Non-Cash Stock-Based Compensation	(39)	(272)
Change in Fair Value of Crude Oil Put Options	14	(203)
Other Non-Cash Expenses	(210)	(1)
Adjusted EBITDA	2,782	5,206

11. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our Property, Plant & Equipment (PP&E) are as follows:

	Nine Months Ended September 30 **2009**	Year Ended December 31 **2008**
Balance at Beginning of Period	1,059	832
Obligations Incurred with Development Activities	25	32
Obligations Discharged with Disposed Properties	(2)	–
Obligations Settled	(25)	(45)
Accretion Expense	51	58
Revisions to Estimates	(19)	159
Effects of Changes in Foreign Exchange Rate	(62)	23
Balance at End of Period [1, 2]	1,027	1,059

[1] Obligations due within 12 months of $35 million (December 31, 2008 – $35 million) have been included in accounts payable and accrued liabilities.
[2] Obligations relating to our oil and gas activities amount to $979 million (December 31, 2008 – $1,009 million) and obligations relating to our chemicals business amount to $48 million (December 31, 2008 – $50 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,353 million (December 31, 2008 – $2,393 million). We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted, risk-free rate of 5.9%. Approximately $367 million included in our asset retirement obligations is expected to be settled over the next five years. The remaining obligations settle beyond five years and are expected to be funded by future cash flows from our operations.

12. DEFERRED CREDITS AND OTHER LIABILITIES

	September 30 **2009**	December 31 **2008**
Deferred Tax Credit	542	709
Long-Term Energy Marketing Derivative Contracts (Note 6)	228	294
Defined Benefit Pension Obligations	71	67
Capital Lease Obligations	61	53
Deferred Transportation Revenue	57	69
Other	125	132
Total	1,084	1,324

13. SHAREHOLDERS' EQUITY

Dividends

Dividends per common share for the three months ended September 30, 2009 were $0.05 per common share (2008 – $0.05). Dividends per common share for the nine months ended September 30, 2009 were $0.15 per common share (2008 – $0.125). Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

14. MARKETING AND OTHER INCOME

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Marketing Revenue, Net (Note 6)	188	149	676	381
Change in Fair Value of Crude Oil Put Options (Note 6)	(23)	9	(218)	(1)
Interest	1	7	4	20
Foreign Exchange Gains (Losses)	93	(33)	112	(34)
Other	37	(1)	61	21
Total	296	131	635	387

15. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by 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)	**2009**	**2008**	**2009**	**2008**
Weighted-average number of common shares outstanding	521.7	525.9	521.0	528.3
Shares issuable pursuant to tandem options	10.3	19.6	10.7	24.9
Shares notionally purchased from proceeds of tandem options	(7.0)	(13.0)	(7.5)	(16.2)
Weighted-average number of diluted common shares outstanding	525.0	532.5	524.2	537.0

In calculating the weighted-average number of diluted common shares outstanding for the three and nine months ended September 30, 2009, we excluded 13,077,285 and 13,236,034 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, 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. During the periods presented, outstanding tandem options were the only potential dilutive instruments.

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

As described in Note 16 to the Audited Consolidated Financial Statements included in our 2008 Form 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 continue to believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations. There have been no significant developments since year-end.

17. CASH FLOWS

(a) Charges and credits to income not involving cash

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Depreciation, Depletion, Amortization and Impairment	358	386	1,180	1,084
Stock-Based Compensation	(19)	(410)	23	(210)
Provision for (Recovery of) Future Income Taxes	(81)	645	(397)	583
Change in Fair Value of Crude Oil Put Options	23	(9)	218	1
Allowance for Doubtful Accounts	(4)	38	(5)	34
Foreign Exchange	(117)	43	(154)	48
Other	14	(1)	22	4
Total	174	692	887	1,544

(b) Changes in non-cash working capital

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Accounts Receivable	212	503	39	(821)
Inventories and Supplies	(13)	260	(142)	(128)
Other Current Assets	(24)	(64)	(12)	(80)
Accounts Payable and Accrued Liabilities	(68)	(1,607)	251	425
Other Current Liabilities	20	12	16	26
Total	127	(896)	152	(578)
Relating to:				
Operating Activities	113	(840)	193	(468)
Financing Activities	–	10	–	10
Investing Activities	14	(66)	(41)	(120)
Total	127	(896)	152	(578)

(c) Other cash flow information

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Interest Paid	70	64	248	212
Income Taxes Paid	179	655	247	816

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $16 million for the three months ended September 30, 2009 (2008 – $38 million) and $59 million for the nine months ended September 30, 2009 (2008 – $72 million).

18. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen is involved in activities relating to Oil and Gas, Syncrude, Energy Marketing and Chemicals in various geographic locations as described in Note 22 to the Audited Consolidated Financial Statements included in our 2008 Form 10-K.

Three months ended September 30, 2009

	Oil and Gas					Syncrude	Energy Marketing	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	176	92	74	478	16	137	9	115	–	1,097
Marketing and Other	3	(6)	–	5	6	–	188	29	71 [2]	296
Total Revenues	179	86	74	483	22	137	197	144	71	1,393
Less: Expenses										
Operating	49	42	23	71	2	62	5	67	–	321
Depreciation, Depletion, Amortization and Impairment	19	59	67	162	2	13	14	12	10	358
Transportation and Other	7	8	2	3	–	5	141	13	6	185
General and Administrative [3]	4	16	13	8	5	–	19	9	39	113
Exploration	–	24	40	7	18 [4]	–	–	–	–	89
Interest	–	–	–	–	–	–	–	2	82	84
Income (Loss) before Income Taxes	100	(63)	(71)	232	(5)	57	18	41	(66)	243
Less: Provisions for (Recovery of) Income Taxes	35	(15)	(30)	102	(5)	14	8	9	(9)	109
Less: Non-Controlling Interests	–	–	–	–	–	–	–	12	–	12
Net Income (Loss)	65	(48)	(41)	130	–	43	10	20	(57)	122
Identifiable Assets	241	7,756 [5]	1,880	5,157	976	1,244	3,114 [6]	704	1,997	23,069
Capital Expenditures										
Development and Other	11	135	31	133	130	17	9	53	7	526
Exploration	–	42	46	32	9	–	–	–	–	129
	11	177	77	165	139	17	9	53	7	655
Property, Plant and Equipment										
Cost	2,516	9,558	3,957	6,165	782	1,424	250	1,086	356	26,094
Less: Accumulated DD&A	2,369	1,955	2,507	2,396	97	264	78	552	234	10,452
Net Book Value	147	7,603 [5]	1,450	3,769	685	1,160	172	534	122	15,642

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $1 million, foreign exchange gains of $93 million and decrease in the fair value of crude oil put options of $23 million.
[3] Includes recovery of stock-based compensation expense of $5 million.
[4] Includes exploration activities primarily in Norway, Nigeria and Colombia.
[5] Includes costs of $5,946 million related to our insitu oil sands projects (Long Lake and future phases).
[6] Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

Three months ended September 30, 2008

	Oil and Gas					Syncrude	Energy Marketing	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	317	192	139	1,141	56	220	17	131	–	2,213
Marketing and Other	2	1	–	6	1	3	149	(12)	(19) [2]	131
Total Revenues	319	193	139	1,147	57	223	166	119	(19)	2,344
Less: Expenses										
Operating	39	48	29	66	2	68	10	79	–	341
Depreciation, Depletion, Amortization and Impairment	46	50	56	192	4	12	4	11	11	386
Transportation and Other	3	–	1	21	–	4	235	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	139	(79)	5	77	1,506
Less: Provisions for (Recovery of) Income Taxes	86	44	13	444	(3)	40	(20)	2	13	619
Less: Non-Controlling Interests	–	–	–	–	–	–	–	1	–	1
Net Income (Loss)	163	112	27	425	53	99	(59)	2	64	886
Identifiable Assets	365	6,301 [5]	1,951	6,502	536	1,218	4,468 [6]	541	333	22,215
Capital Expenditures										
Development and Other	29	245	46	189	35	19	2	24	10	599
Exploration	–	34	38	43	11	–	–	–	–	126
	29	279	84	232	46	19	2	24	10	725
Property, Plant and Equipment										
Cost	2,402	7,697	3,670	5,558	358	1,363	268	896	322	22,534
Less: Accumulated DD&A	2,220	1,725	2,072	1,456	95	232	72	495	199	8,566
Net Book Value	182	5,972 [5]	1,598	4,102	263	1,131	196	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 insitu oil sands projects (Long Lake and future phases).
[6] Approximately 85% of Marketing's identifiable assets are accounts receivable and inventories.

Nine months ended September 30, 2009

	Oil and Gas					Syncrude	Energy Marketing	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	513	281	225	1,574	55	320	29	348	–	3,345
Marketing and Other	10	2	–	13	6	1	676	44	(117) [2]	635
Total Revenues	523	283	225	1,587	61	321	705	392	(117)	3,980
Less: Expenses										
Operating	145	125	73	175	6	205	21	196	–	946
Depreciation, Depletion, Amortization and Impairment	92	184	215	537	11	33	21	53	34	1,180
Transportation and Other	25	19	18	14	–	17	469	37	19	618
General and Administrative [3]	5	58	51	15	29	1	68	34	119	380
Exploration	–	53	87	26	53 [4]	–	–	–	–	219
Interest	–	–	–	–	–	–	–	6	220	226
Income (Loss) before Income Taxes	256	(156)	(219)	820	(38)	65	126	66	(509)	411
Less: Provisions for (Recovery of) Income Taxes	89	(39)	(81)	358	(29)	16	52	15	(264)	117
Less: Non-Controlling Interests	–	–	–	–	–	–	–	17	–	17
Net Income (Loss)	167	(117)	(138)	462	(9)	49	74	34	(245)	277
Identifiable Assets	241	7,756 [5]	1,880	5,157	976	1,244	3,114 [6]	704	1,997	23,069
Capital Expenditures										
Development and Other	62	519	106	391	328	56	20	161	17	1,660
Exploration	–	189	111	109	50	–	–	–	–	459
Proved Property Acquisitions	–	755	–	–	–	–	–	–	–	755
	62	1,463	217	500	378	56	20	161	17	2,874
Property, Plant and Equipment										
Cost	2,516	9,558	3,957	6,165	782	1,424	250	1,086	356	26,094
Less: Accumulated DD&A	2,369	1,955	2,507	2,396	97	264	78	552	234	10,452
Net Book Value	147	7,603 [5]	1,450	3,769	685	1,160	172	534	122	15,642

[1] Includes results of operations from producing activities in Colombia.
[2] Includes interest income of $4 million, foreign exchange gains of $112 million, decrease in the fair value of crude oil put options of $218 million and other losses of $15 million.
[3] Includes stock-based compensation expense of $51 million.
[4] Includes exploration activities primarily in Norway, Nigeria and Colombia.
[5] Includes costs of $5,946 million related to our insitu oil sands projects (Long Lake and future phases).
[6] Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

Nine months ended September 30, 2008

	Oil and Gas					Syncrude	Energy Marketing	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	United Kingdom	Other Countries [1]					
Net Sales	912	545	518	3,053	156	567	52	351	–	6,154
Marketing and Other	9	2	4	17	2	3	381	(13)	(18) [2]	387
Total Revenues	921	547	522	3,070	158	570	433	338	(18)	6,541
Less: Expenses										
Operating	129	137	77	186	7	208	33	221	–	998
Depreciation, Depletion, Amortization and Impairment	120	144	192	505	12	36	11	32	32	1,084
Transportation and Other	7	10	2	21	–	11	574	41	25	691
General and Administrative [3,4]	(9)	13	23	(7)	14	1	63	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	314	(248)	12	(169)	3,299
Less: Provisions for (Recovery of) Income Taxes	234	57	55	1,181	(3)	89	(72)	5	(146)	1,400
Less: Non-Controlling Interests	–	–	–	–	–	–	–	3	–	3
Net Income (Loss)	438	145	103	1,142	38	225	(176)	4	(23)	1,896
Identifiable Assets	365	6,301 [6]	1,951	6,502	536	1,218	4,468 [7]	541	333	22,215
Capital Expenditures										
Development and Other	61	855	180	410	73	39	3	57	23	1,701
Exploration	9	146	147	114	30	–	–	–	–	446
Proved Property Acquisitions	–	2	–	–	–	–	–	–	–	2
	70	1,003	327	524	103	39	3	57	23	2,149
Property, Plant and Equipment										
Cost	2,402	7,697	3,670	5,558	358	1,363	268	896	322	22,534
Less: Accumulated DD&A	2,220	1,725	2,072	1,456	95	232	72	495	199	8,566
Net Book Value	182	5,972 [6]	1,598	4,102	263	1,131	196	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 severance accrual of $7 million in connection with North Vancouver technology conversion project.
[4] Includes a 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 insitu oil sands projects (Long Lake and future phases).
[7] Approximately 85% of Marketing's identifiable assets are accounts receivable and inventories.

19. 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 Statements and summaries of differences from Canadian GAAP are as follows:

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	
	2009	**2008**	**2009**	**2008**
Revenues and Other Income				
Net Sales	1,097	2,213	3,345	6,154
Marketing and Other (v); (vi)	344	366	702	470
	1,441	2,579	4,047	6,624
Expenses				
Operating	321	341	946	998
Depreciation, Depletion, Amortization and Impairment	358	386	1,180	1,084
Transportation and Other (v)	191	291	616	687
General and Administrative (iv)	89	(272)	394	180
Exploration	89	112	219	245
Interest	84	16	226	59
	1,132	874	3,581	3,253
Income before Provision for Income Taxes	309	1,705	466	3,371
Provision for (Recovery of) Income Taxes				
Current	190	(26)	514	817
Deferred (iv); (vi); (vii)	(68)	724	(384)	610
	122	698	130	1,427
Net Income	187	1,007	336	1,944
Less: Net Income Attributable to Non-Controlling Interests	(12)	(1)	(17)	(3)
Net Income Attributable to Nexen Inc. – US GAAP [1]	175	1,006	319	1,941
Earnings Per Common Share ($/share) (Note 15)				
Basic	0.34	1.91	0.61	3.67
Diluted	0.33	1.89	0.61	3.61

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Net Income Attributable to Nexen Inc – Canadian GAAP	122	886	277	1,896
Impact of US Principles, Net of Income Taxes:				
Stock-based Compensation (iv)	17	(26)	(11)	(11)
Inventory Valuation (vi)	29	146	46	56
Deferred Taxes (vii)	7	–	7	–
Net Income Attributable to Nexen Inc – US GAAP	175	1,006	319	1,941

Unaudited Consolidated Balance Sheet – US GAAP

(Cdn$ millions, except share amounts)	September 30 **2009**	December 31 **2008**
Assets		
Current Assets		
Cash and Cash Equivalents	1,897	2,003
Restricted Cash	216	103
Accounts Receivable	2,877	3,163
Inventories and Supplies (vi)	601	426
Other	199	169
Total Current Assets	5,790	5,864
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,845 (December 31, 2008 - $10,786) (i); (iii)	15,593	14,873
Goodwill	346	390
Deferred Income Tax Assets	916	351
Deferred Charges and Other Assets	386	570
Total Assets	23,031	22,048
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities (iv)	3,430	3,384
Accrued Interest Payable	81	67
Dividends Payable	26	26
Total Current Liabilities	3,537	3,477
Long-Term Debt	7,429	6,578
Deferred Income Tax Liabilities (i); (ii); (iv); (vi); (vii)	2,635	2,543
Asset Retirement Obligations	992	1,024
Deferred Credits and Other Liabilities (ii)	1,188	1,428
Shareholders' Equity		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2009 – 521,846,559 shares		
2008 – 519,448,590 shares	1,025	981
Contributed Surplus	1	2
Retained Earnings (i) – (vii)	6,413	6,172
Accumulated Other Comprehensive Loss (ii)	(258)	(209)
Total Nexen Inc. Shareholders' Equity	7,181	6,946
Canexus Non-Controlling Interests	69	52
Total Shareholders Equity	7,250	6,998
Commitments, Contingencies and Guarantees (Note 16)		
Total Liabilities and Shareholders' Equity	23,031	22,048

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Net Income Attributable to Nexen Inc. – US GAAP	175	1,006	319	1,941
Other Comprehensive Income (Loss), Net of Income Taxes:				
Foreign Currency Translation Adjustment	(26)	41	(49)	60
Comprehensive Income Attributable to Nexen Inc. – US GAAP	149	1,047	270	2,001

Unaudited Consolidated Statement of Accumulated Other Comprehensive Loss – US GAAP

	September 30 **2009**	December 31 **2008**
Foreign Currency Translation Adjustment	(183)	(134)
Unamortized Defined Benefit Pension Plan Costs (ii)	(75)	(75)
Accumulated Other Comprehensive Loss	(258)	(209)

Notes to the Unaudited Consolidated US GAAP Financial Statements:

i. Under Canadian GAAP, we defer certain development costs to PP&E. Under US principles, these costs have been included in operating expenses in prior years. As a result PP&E is lower under US GAAP by $30 million (December 31, 2008 – $30 million).

ii. US GAAP requires the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability. At September 30, 2009 and December 31, 2008, the unfunded amount of our defined benefit pension plans that was not included in the pension liability under Canadian GAAP was $104 million. This amount has been included in deferred credits and other liabilities and $75 million, net of income taxes, has been included in Accumulated Other Comprehensive Income (AOCI).

iii. On January 1, 2003, we adopted *Accounting for Asset Retirement Obligations* 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 PP&E under US GAAP being lower by $19 million.

iv. 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. In addition, under Canadian principles, we retroactively adopted EIC-162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, US GAAP requires the accelerated recognition of stock-based compensation expense for such employees for awards granted on or after January 1, 2006. As a result under US GAAP:

- general and administrative (G&A) expense is lower by $24 million and higher by $14 million ($17 million and $11 million, net of income taxes) for the three and nine months ended September 30, 2009, respectively (2008 – higher by $36 million and $15 million, respectively ($26 million and $11 million, net of income taxes)); and
- accounts payable and accrued liabilities are higher by $72 million as at September 30, 2009 (December 31, 2008 – $58 million).

v. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Losses of $6 million and gains of $2 million for the three and nine months ended September 30, 2009, respectively, were reclassified from marketing and other income to transportation and other expense (gains of nil and $4 million were reclassified for the three and nine months ended September 30, 2008).

vi. Under Canadian GAAP, we carry our commodity inventory held for trading purposes at fair value, less any costs to sell. 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 $42 million and $69 million ($29 million and $46 million, net of income taxes) for the three and nine months ended September 30, 2009, respectively (2008 – higher by $235 million and $87 million ($146 million and $56 million, net of income taxes)); and
- inventories are higher by $11 million as at September 30, 2009 (December 31, 2008 – lower by $58 million).

vii. On January 1, 2007, we adopted *Accounting for Uncertainty in Income Taxes* regarding accounting and disclosure for uncertain tax positions. On the adoption of this US guidance, we recorded a cumulative effect of a change in accounting principle of $28 million. This amount increased our deferred income tax liabilities, and decreased our retained earnings as at January 1, 2007 in our US GAAP – Unaudited Consolidated Balance Sheet. During the quarter our uncertain tax position changed. As a result:

- Deferred income tax expense is lower by $7 million for the three and nine months ended September 30, 2009 (2008 – nil); and
- Deferred income tax liabilities are higher by $21 million as at September 30, 2009 (December 31, 2008 – higher by $28 million).

As at September 30, 2009, the total amount of our unrecognized tax benefit was approximately $273 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Unaudited Consolidated Statement of Income. As at September 30, 2009, the total amount of interest

and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP – Unaudited Consolidated Balance Sheet was approximately $7 million. We had no interest or penalties included in the US GAAP – Unaudited Consolidated Statement of Income for the three and nine months ended September 30, 2009.

Our income tax filings are subject to audit by taxation authorities and as at September 30, 2009 the following tax years remained subject to examination, (i) Canada – 1985 to date (ii) United Kingdom – 2007 to date and (iii) United States – 2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next 12 months.

Changes in Accounting Policies – US GAAP

Business Combinations

On January 1, 2009, we prospectively adopted *Business Combinations* which establishes principles and requirements of the acquisition method for business combinations and related disclosures. The adoption of this statement did not impact our results of operations or financial position.

Non-Controlling Interests

On January 1, 2009, we prospectively adopted *Non-controlling Interests in Consolidated Financial Statements.* 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. The adoption of this statement did not have a material impact on our results of operations or financial position. The presentation changes have been included in the Consolidated Financial Statements, as applicable.

Derivative and Hedging Accounting and Disclosures

On January 1, 2009, we prospectively adopted *Disclosures about Derivative Instruments and Hedging Activities.* 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. The disclosures required by this standard are provided in Notes 6 and 7.

On April 1, 2009, we prospectively adopted three changes to FASB guidance intended to improve guidance and disclosures on fair value measurement and impairments. The positions clarify fair value accounting specifically regarding: inactive markets and distressed transactions, other-than-temporary impairments, and expanded fair value disclosures for financial instruments in interim periods. The adoption of these positions did not have a material impact on our results of operation or financial position.

Subsequent Events

On April 1, 2009, we prospectively adopted *Subsequent Events*. The new standard reflects the existing principles of current subsequent events accounting guidance and retains the notion and definition of "available to be issued" financial statements. The new standard requires disclosure of the date through which subsequent events have been evaluated and clarifies that original issuance of financial statements means both "issued" or "available to be issued". The adoption of this standard did not have a material impact on our results of operation or financial position.

New Accounting Pronouncements – US GAAP

In December 2008, FASB issued *Employers Disclosures about Postretirement Benefit Plan Assets*. This position provides guidance on disclosures about plan assets of a defined benefit pension or other postretirement plans. This position is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In June 2009, FASB issued *Amendments to Consolidation of Variable Interest Entities.* It retains the scope of the previous guidance with the addition of entities previously considered qualifying special-purpose entities and eliminates the previous quantitative approach for a qualitative analysis in determining whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The Statement is further amended to require ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity and requires enhanced disclosures about an enterprise's involvement in a variable interest entity. The Statement is effective at the beginning of the first annual reporting period after November 15, 2009. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

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

(all dollar amounts in Cdn$ unless noted)	Quarters – 2009 1st	2nd	3rd	Quarters – 2008 1st	2nd	3rd	4th	Total Year 2008
PRICES:								
WTI Crude Oil (US$/bbl)	43.08	59.62	68.30	97.90	123.98	117.98	58.73	99.65
Nexen Average – Oil (Cdn$/bbl)	50.41	68.32	72.95	93.00	118.00	115.56	59.90	96.92
NYMEX Natural Gas (US$/mmbtu)	4.48	3.81	3.44	8.75	11.48	8.95	6.41	8.90
Nexen Average – Gas (Cdn$/mcf)	5.11	3.77	3.04	7.97	10.21	8.65	6.34	8.44
NETBACKS:								
Canada – Heavy Oil								
Sales (mbbls/d)	15.4	14.7	14.0	16.2	16.4	16.0	16.2	16.2
Price Received ($/bbl)	35.35	56.05	59.88	65.94	93.16	97.91	41.14	74.51
Royalties & Other	6.86	12.83	13.47	16.65	22.61	24.24	8.81	18.07
Operating Costs	15.42	16.41	16.21	15.76	17.17	16.99	16.69	16.66
Netback	13.07	26.81	30.20	33.53	53.38	56.68	15.64	39.78
Canada – Natural Gas								
Sales (mmcf/d)	137	134	136	127	126	133	138	131
Price Received ($/mcf)	4.75	3.42	2.85	7.57	9.67	8.00	6.06	7.73
Royalties & Other	0.59	0.15	0.21	1.18	1.53	1.52	1.07	1.32
Operating Costs	1.54	1.59	1.82	1.67	1.84	1.84	1.66	1.75
Netback	2.62	1.68	0.82	4.72	6.30	4.64	3.33	4.66
Yemen								
Sales (mbbls/d)	54.7	51.4	43.2	62.5	57.4	54.2	51.7	56.4
Price Received ($/bbl)	52.30	69.40	76.31	96.57	120.39	115.92	64.48	99.87
Royalties & Other	19.43	31.94	32.08	48.07	59.21	52.47	26.33	46.94
Operating Costs	9.62	10.39	12.43	7.76	8.80	7.82	9.80	8.51
In-country Taxes	4.92	9.01	9.70	11.82	17.45	16.11	7.60	13.31
Netback	18.33	18.06	22.10	28.92	34.93	39.52	20.75	31.11
Syncrude								
Sales (mbbls/d)	19.8	14.9	22.5	19.3	19.1	22.9	22.3	20.9
Price Received ($/bbl)	55.48	71.58	74.54	101.70	130.90	126.56	65.48	105.47
Royalties & Other	0.40	8.84	8.31	11.93	22.08	21.89	4.97	15.11
Operating Costs	36.95	57.21	29.50	35.16	45.09	32.40	34.67	36.53
Netback	18.13	5.53	36.73	54.61	63.73	72.27	25.84	53.83

[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 – 2009 1st	2nd	3rd	Quarters – 2008 1st	2nd	3rd	4th	Total Year 2008
United States								
Crude Oil:								
Sales (mbbls/d)	10.4	12.1	9.5	13.7	11.3	8.5	3.8	9.3
Price Received ($/bbl)	46.27	66.23	72.27	94.07	120.77	122.46	58.43	104.94
Natural Gas:								
Sales (mmcf/d)	50	61	63	112	99	70	31	78
Price Received ($/mcf)	5.93	4.58	3.56	9.03	11.80	10.14	8.09	10.07
Total Sales Volume (mboe/d)	18.8	22.2	20.0	32.4	27.8	20.2	8.9	22.3
Price Received ($/boe)	41.50	48.53	45.43	71.10	91.08	86.75	52.77	79.02
Royalties & Other	4.52	4.94	4.77	9.53	12.88	12.30	7.89	11.03
Operating Costs	13.79	13.11	12.40	8.20	9.28	15.62	21.58	11.57
Netback	23.19	30.48	28.26	53.37	68.92	58.83	23.30	56.42
United Kingdom								
Crude Oil:								
Sales (mbbls/d)	100.8	97.0	70.4	108.9	89.0	107.0	96.4	100.3
Price Received ($/bbl)	51.60	69.42	73.15	93.38	118.24	114.89	58.60	96.23
Natural Gas:								
Sales (mmcf/d)	21	17	17	22	24	18	16	20
Price Received ($/mcf)	5.50	3.67	2.64	6.82	7.06	7.53	5.44	6.78
Total Sales Volume (mboe/d)	104.3	99.8	73.2	112.6	93.0	110.0	99.0	103.7
Price Received ($/boe)	50.97	68.10	70.95	91.67	114.95	112.99	57.91	94.45
Operating Costs	5.48	5.85	10.34	5.67	7.42	6.71	7.39	6.75
Netback	45.49	62.25	60.61	86.00	107.53	106.28	50.52	87.70
Other Countries								
Sales (mbbls/d)	5.5	3.6	2.6	6.0	5.7	5.7	5.8	5.8
Price Received ($/bbl)	41.68	66.83	70.49	91.85	113.18	120.11	72.43	98.98
Royalties & Other	3.26	5.17	5.38	7.46	8.95	9.42	5.81	7.88
Operating Costs	4.81	5.73	5.70	4.74	4.43	5.14	3.79	4.52
Netback	33.61	55.93	59.41	79.65	99.80	105.55	62.83	86.58
Company-Wide								
Oil and Gas Sales (mboe/d)	241.4	228.9	198.2	270.1	240.4	250.9	226.9	247.0
Price Received ($/boe)	47.56	61.28	63.00	85.90	108.26	106.22	56.94	89.78
Royalties & Other	5.64	9.23	9.58	14.87	19.92	16.98	8.22	15.06
Operating Costs	10.62	11.95	13.60	9.46	11.89	10.90	12.01	11.04
In-country Taxes	1.11	2.02	2.11	2.74	4.16	3.48	1.73	3.04
Netback	30.19	38.08	37.71	58.83	72.29	74.86	34.98	60.64

[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	
	2009	**2008**	**2009**	**2008**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	73.7	100.0	91.6	102.0
Yemen	48.7	54.1	51.5	58.0
Canada	14.2	16.0	14.9	16.2
United States	9.5	8.5	10.6	11.2
Long Lake Bitumen [2]	5.5	5.2	7.6	3.0
Other Countries	2.6	5.7	3.9	5.7
Syncrude (mbbls/d) [3]	22.5	22.9	19.1	20.4
	176.7	212.4	199.2	216.5
Natural Gas (mmcf/d)				
United Kingdom	17	17	18	19
Canada	143	133	139	128
United States	63	70	58	94
	223	220	215	241
Total Production (mboe/d)	214	249	235	257

Production Volumes (after royalties)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	**2008**	**2009**	**2008**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	73.7	100.0	91.6	102.0
Yemen	28.3	29.9	31.0	30.3
Canada	10.9	12.0	11.6	12.3
United States	8.5	7.3	9.6	9.7
Long Lake Bitumen [2]	5.5	5.2	7.6	3.0
Other Countries	2.4	5.1	3.6	5.3
Syncrude (mbbls/d) [3]	20.0	18.9	17.6	17.3
	149.3	178.4	172.6	179.9
Natural Gas (mmcf/d)				
United Kingdom	17	17	17	19
Canada	137	107	130	107
United States	56	60	52	80
	210	184	199	206
Total Production (mboe/d)	184	209	206	214

[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] Currently considered a mining operation for US reporting purposes.

Cash Flow from Operations [1]

(Cdn$ millions)	Three Months Ended September 30 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008
Oil & Gas and Syncrude				
United Kingdom	400	1,056	1,382	2,857
Yemen [2]	79	195	244	543
Canada	23	131	85	344
United States	34	93	87	405
Other Countries	13	45	30	108
Marketing	29	(65)	147	(216)
Syncrude	70	151	98	350
	648	1,606	2,073	4,391
Chemicals	29	28	84	60
	677	1,634	2,157	4,451
Interest and Other Corporate Items	(147)	(56)	(369)	(203)
Income Taxes [3]	(151)	107	(409)	(578)
Cash Flow from Operations [1]	379	1,685	1,379	3,670

[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 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008
Cash Flow from Operating Activities	461	968	1,359	3,299
Changes in Non-Cash Working Capital	(113)	840	(193)	468
Other	49	(117)	234	(79)
Impact of Annual Crude Oil Put Options	(18)	(6)	(21)	(18)
Cash Flow from Operations	379	1,685	1,379	3,670
Weighted-average Number of Common Shares Outstanding (millions of shares)	521.7	525.9	521.0	528.3
Cash Flow from Operations Per Common Share ($/share)	0.73	3.20	2.65	6.95

[2] After in-country cash taxes of $39 million for the three months ended September 30, 2009 (2008 – $81 million) and $105 million for the nine months ended September 30, 2009 (2008 – $239 million).

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

CORPORATE INFORMATION

OFFICERS

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

Marvin F. Romanow
President and
Chief Executive Officer

Kevin J. Reinhart
Senior Vice President
and Chief Financial Officer

Laurence Murphy
Executive Vice President,
International Oil and Gas

Gary H. Nieuwenburg
Executive Vice President, Canada

James T. Arnold
Senior Vice President,
Synthetic Crude

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

Kim D. McKenzie
Vice President and Chief Information Officer

Eric B. Miller
Vice President, General Counsel and Secretary

Una M. Power
Vice President, Corporate Planning and Business Development

Brendon T. Muller
Controller

J. Michael Backus
Treasurer

Rick C. Beingessner
Assistant Secretary

C. James Cummings
Assistant Secretary

DIRECTORS

William B. Berry

Robert G. Bertram

Dennis G. Flanagan

S. Barry Jackson

Kevin J. Jenkins

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

Eric P. Newell, O.C.

Thomas C. O'Neill

Marvin F. Romanow

Francis M. Saville, Q.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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