

# MANAGEMENT'S DISCUSSION AND ANALYSIS

Despite a 38% decrease in WTI in 2009, our strong netbacks helped generate \$1.9 billion of cash flow from operating activities and \$536 million of net income.



## Part II *(continued)*

### ITEM 7: Management's Discussion and Analysis of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 21 to the Consolidated Financial Statements. The date of this discussion is February 17, 2010. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Oil and gas volumes, reserves and related performance measures are 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 an after-royalty basis in tabular format.

*1 Investors should read the Special Note Regarding Forward-Looking Statements on page 96.*

*2 Canadian investors should read the Special Note to Canadian Investors on page 97 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.*

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## PART II

### ITEM 7.

#### Management's Discussion and Analysis of Financial Condition and Results of Operations

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### EXECUTIVE SUMMARY

#### 2009 Results

<i>(Cdn\$ millions, except otherwise indicated)</i>	2009	2008	2007
Production before Royalties (mboe/d) <sup>1</sup>	243	250	254
Production after Royalties (mboe/d)	213	210	207
Cash Flow from Operating Activities	1,886	4,354	2,830
Net Income	536	1,715	1,086
Earnings per Common Share, Basic (\$/share)	1.03	3.26	2.06
Net Debt <sup>2</sup>	5,551	4,575	4,404

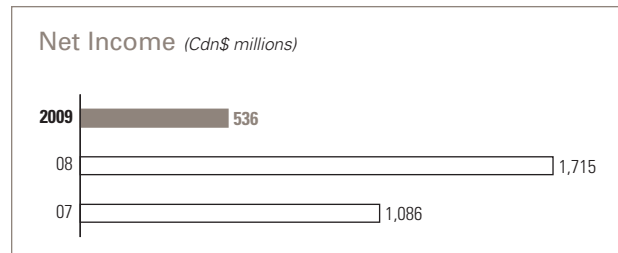
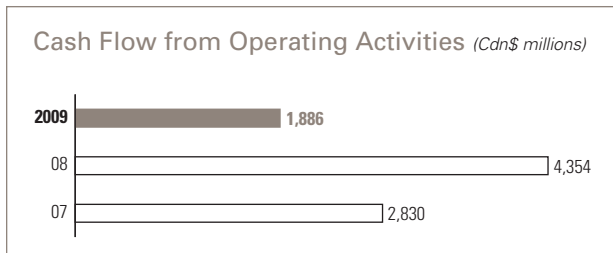
<sup>1</sup> Production before royalties reflects our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

<sup>2</sup> Long-term debt and short-term borrowings less cash and cash equivalents.

In 2009, we generated cash flow from operating activities of \$1.9 billion and net income of \$536 million. The decline from the prior year was primarily due to lower commodity prices as WTI averaged US\$61.80/bbl for the year, down 38% from 2008. WTI started the year at approximately US\$46/bbl before recovering to almost US\$80/bbl by the end of 2009. Dated Brent decreased 37% to average US\$61.51/bbl over the same period. The impact of lower commodity prices was partially offset by changes in the US/Canadian foreign exchange rate, which averaged 88 cents in 2009 as compared to 94 cents last year.

Production before royalties averaged 243,000 boe/d in 2009, 3% below last year's volumes. At Buzzard, planned downtime reduced our production, while in Yemen our fields continued to mature. These decreases were partially

offset by the start-up of the Ettrick field in the UK North Sea, the Longhorn field in the US Gulf of Mexico and higher bitumen production at Long Lake. Our production after royalties increased slightly over last year as a result of lower royalty rates on our Canadian gas production and higher Long Lake bitumen volumes. Production after royalties increased slightly to average 213,000 boe/d, as higher margin barrels displaced higher royalty barrels. Our production in the fourth quarter averaged 265,000 boe/d, 24% higher than the third quarter as Buzzard returned to full rates during the quarter and we brought Longhorn and Ettrick on stream. In 2010, we expect production to range between 230,000 and 280,000 boe/d before royalties. Over the last three years, our production after royalties has grown at an average compounded rate of 11%.



Despite lower commodity prices, our cash netbacks remain strong. Much of our production has low operating costs and royalties, resulting in annual cash netbacks of \$38.55/boe (before royalties).

Our net debt increased by \$976 million as capital investments, including costs to acquire an additional 15% working interest in Long Lake early in the year, exceeded our cash flow from operating activities by \$1.6 billion. This increase was partially offset by the weaker US dollar, which reduced our US-dollar-denominated debt and cash by approximately \$900 million.

Our financial position is strong. For the past several years, we invested significant capital in a number of major development projects, such as Buzzard and Long Lake. With the investment in these projects behind us and production ramping up at Ettrick, Longhorn and Long Lake, we expect to fund our next generation of new growth projects from operating cash flows. These projects include Golden Eagle in the UK North Sea, Usan offshore West Africa, future phases of Long Lake and shale gas in the Horn River Basin in northeast British Columbia, as well as several exploration prospects.

Our available liquidity is currently \$3.3 billion, comprised of cash and undrawn committed credit facilities, most of which are available until 2012. In response to improving credit markets, we issued US\$1 billion of senior notes during the year, which were used to repay a portion of our outstanding term credit facilities as well as for general corporate purposes. Issuing this debt increased the average term-to-maturity of our debt to 17 years.

## Strategy Progress

(Cdn\$ millions)	2009	2008	2007
Capital Investment, including Acquisitions	3,497	3,066	3,401
Proved Oil and Gas Reserves before Royalties (mmbœ) <sup>1</sup>	1,011	988	1,058
Proved Oil and Gas Reserves after Royalties (mmbœ) <sup>1</sup>	920	926	917

<sup>1</sup> Includes developed and undeveloped proved reserves as at December 31.

Our strategy is to build a sustainable energy company focused in three growth areas: oil sands, conventional exploration and development, and unconventional gas. Our investment in these areas generated the following results in 2009:

- oil sands—we acquired an additional 15% interest in the Long Lake project and joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the SAGD bitumen extraction process and the upgrader for Phase 1, as well as future phases. During the year, we confirmed that our Long Lake design gasifies the bottom of the bitumen barrel and that we can upgrade bitumen to premium synthetic oil. Bitumen production ramped up as we increased our steam availability;
- conventional exploration and development—our conventional exploration program was focused in the UK and Norwegian North Sea, deep-water Gulf of Mexico and offshore West Africa. We were successful by bringing Ettrick and Longhorn on stream during the year and from advancing the developments of Usan and the Buzzard H<sub>2</sub>S processing facilities. We had exploration success during the year at Golden Eagle and Owowo; and
- unconventional gas—we have a significant land position in the Horn River Basin in northeast British Columbia. Our 2009 drilling and completion program realized substantial cost savings and productivity improvements and demonstrated that we could successfully frac the shale to allow the gas to flow. We now have five shale gas wells on stream and achieved peak rates of over 15 mmcf/d during the year.

During 2009, our proved oil and gas reserves additions replaced 205% of our oil and gas production (198% after royalties) before the year-end transition to new SEC reserves rules. Excluding economic revisions, we replaced 187% of our oil and gas production (202% after royalties). The difference in economic revisions between before and after royalties reflects an increase in oil sands royalties related to higher oil prices.

	Oil and Gas	
	Before Royalties	After Royalties
<i>(mmboe)</i>		
<b>Production</b>	90	78
<b>Proved Reserve Changes excluding Production</b>		
Net Additions	168	157
Economic Revisions	16	(2)
	184	155

The majority of our additions before economic revisions relate to our Long Lake acquisition, successful exploitation of our North Sea fields at Buzzard and Telford, and elsewhere at Long Lake, offshore West Africa, Syncrude and Masila. Economic revisions are largely related to positive revisions from oil price increases, somewhat offset by negative revisions from decreases in gas prices.

## Outlook

In 2010, we expect our annual production to grow approximately 4 to 6%, assuming the midpoint of our guidance, and range from 230,000 to 280,000 boe/d (200,000 to 250,000 boe/d after royalties). This growth reflects a full year of production from Ettrick and Longhorn,

and increasing volumes from Long Lake. At the high end of our guidance, our production growth would be as high as 15%. The low end includes the possibility of advancing the start-up of the fourth platform at Buzzard, which is currently scheduled for 2011. Advancement to 2010 would only be required if we see higher than expected levels of hydrogen sulphide. The downtime associated with advancing the start-up could reduce annual volumes by 10,000 to 15,000 boe/d.

Our capital investment plans for 2010 total \$2.5 billion. We plan to finance this investment through cash flow from operating activities and existing cash and cash equivalents. Our capital program will advance our future growth areas as we move forward with developing several major identified projects, including Buzzard, Usan, Golden Eagle and Horn River shale gas. We also plan to spend approximately \$575 million drilling 14 wells to advance our new growth exploration and appraisal opportunities, primarily in the North Sea and the Gulf of Mexico. We continue to monitor economic conditions and commodity prices and are prepared to adjust our capital investment program accordingly.

At December 31, 2009, we had \$1.7 billion of cash on hand, and \$1.6 billion of undrawn committed credit facilities. The primary debt maturity in the next few years is our \$3.2 billion term credit facility, which matures in 2012, of which \$1.6 billion was drawn at December 31, 2009 and \$407 million was utilized to support outstanding letters of credit. We also have \$492 million in undrawn uncommitted credit facilities at December 31, 2009, of which \$86 million was utilized to support outstanding letters of credit. The average term-to-maturity of our debt is approximately 17 years.

## CAPITAL INVESTMENT

<i>(Cdn\$ millions)</i>	Estimated 2010	2009	2008
Major Development	700	726	1,437
Early Stage Development	300	100	167
New Growth Exploration	575	582	582
Core Asset Development	825	1,814	731
Total Oil & Gas <sup>1</sup>	2,400	3,222	2,917
Energy Marketing, Corporate, Chemicals and Other	100	275	149
<b>Total Capital</b>	<b>2,500</b>	<b>3,497</b>	<b>3,066</b>

<sup>1</sup> Includes capital related to capitalized interest and the Long Lake upgrader, but excludes cash flows related to geological and geophysical expenditures.

Our strategy and capital programs are focused on growing long-term value for our shareholders responsibly.

To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- exploration and new growth projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning toward less mature basins and unconventional resource plays. Key focus areas include Athabasca oil sands, Canadian unconventional gas plays, the North Sea, deep-water Gulf of Mexico, and offshore West Africa—areas we believe have attractive fiscal terms and significant remaining opportunity and where we have a competitive advantage.

## 2009 Capital<sup>1</sup>

<i>(Cdn\$ millions)</i>	<b>Major Development</b>	<b>Early Stage Development</b>	<b>New Growth Exploration</b>	<b>Core Asset Development</b>	<b>Total</b>
<b>Oil and Gas</b>					
United Kingdom	128	–	143	355	626
Canada	–	–	214 <sup>2</sup>	81	295
Synthetic	–	100	1	1,202 <sup>3</sup>	1,303
Syncrude	–	–	–	87	87
United States	112	–	157	16	285
Yemen	–	–	–	69	69
Nigeria	486	–	20	–	506
Other Countries	–	–	47	4	51
	<b>726</b>	<b>100</b>	<b>582</b>	<b>1,814</b>	<b>3,222</b>
Chemicals	144	–	–	70	214
Energy Marketing, Corporate and Other	–	–	–	61	61
<b>Total Capital</b>	<b>870</b>	<b>100</b>	<b>582</b>	<b>1,945</b>	<b>3,497</b>
<b>As a % of Total Capital</b>	<b>25%</b>	<b>3%</b>	<b>16%</b>	<b>56%</b>	<b>100%</b>

<sup>1</sup> Excludes geological and geophysical expenditures of \$81 million.

<sup>2</sup> Includes shale gas in northeast British Columbia.

<sup>3</sup> Includes \$755 million to acquire an additional 15% working interest at Long Lake.

We invested \$2.8 billion on oil and gas activities and added 184 mmbœ of proved reserves and 349 mmbœ of probable reserves (before royalties) before the year-end transition to new SEC reserve rules. We are not carrying any proved or probable reserves for our discoveries in the Eastern Gulf of Mexico, at Knotty Head or for our shale gas lands. A summary of our 2009 capital investment program and reserve additions are shown in the table below. In this section, production and reserves are before royalties. Additional information on our oil and gas reserves can be found in Items 1 and 2 *Business and Properties* (pages 23 to 31) and in Item 8 *Consolidated Financial Statements and Supplementary Data* (pages 150 to 158).

	<b>Capital Investment<sup>1</sup></b> <i>(Cdn\$ millions)</i>	<b>Production<sup>2</sup></b> <i>(mmbœ)</i>	<b>Proved Reserve Additions<sup>2</sup></b> <i>(mmbœ)</i>	<b>Probable Reserve Additions<sup>2</sup></b> <i>(mmbœ)</i>
Conventional Exploration and Production	1,649	80	70	13
Unconventional—Oil Sands	942	10	114	336
Unconventional—Shale Gas	216	–	–	–
<b>Total Oil and Gas</b>	<b>2,807</b>	<b>90</b>	<b>184</b>	<b>349</b>

<sup>1</sup> Oil and gas capital investment excludes amounts related to capitalized interest, Long Lake upgrader, marketing, corporate, chemicals and other.

<sup>2</sup> Before royalties and the adoption of the new SEC rules.

## 2010 Estimated Capital

(Cdn\$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
<b>Oil and Gas</b>					
United Kingdom	75	–	250	425	750
Canada	–	200	–	20	220
Synthetic	–	100	–	200	300
Syncrude	–	–	–	100	100
United States	50	–	125	50	225
Yemen	–	–	–	30	30
Nigeria	575	–	50	–	625
Other Countries	–	–	150	–	150
	<b>700</b>	<b>300</b>	<b>575</b>	<b>825</b>	<b>2,400</b>
Chemicals	55	–	–	10	65
Energy Marketing, Corporate and Other	–	–	–	35	35
<b>Total Capital</b>	<b>755</b>	<b>300</b>	<b>575</b>	<b>870</b>	<b>2,500</b>
<b>As a % of Total Capital</b>	<b>30%</b>	<b>12%</b>	<b>23%</b>	<b>35%</b>	<b>100%</b>

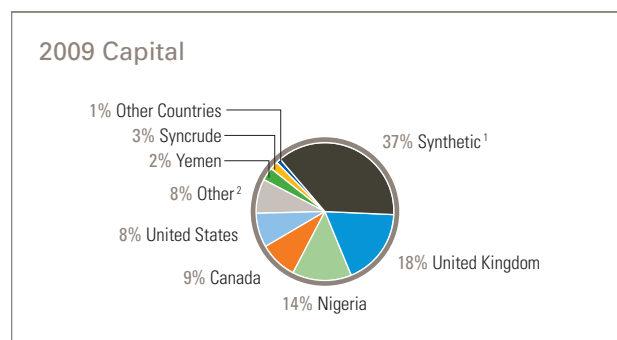
### SYNTHETIC

In 2009, we invested \$755 million on the acquisition of an additional 15% interest in the Long Lake project and joint venture lands. This added 86 mmboc of proved and 220 mmboc of probable bitumen reserves (before royalties). In addition, core-hole delineation activities on the first phase of Long Lake added 21 mmboc of proved bitumen reserves (before royalties), while lease delineation work on Phase 2 added 116 mmboc of probable bitumen reserves (before royalties).

With the completion of the turnaround at Long Lake, steam reliability has improved significantly and steam rates are at an all-time high of over 105,000 bbls/d and increasing. As a result, we are injecting more steam into more wells than ever before, with 57 well pairs now on production and steam circulating in an additional 19 pairs. These circulating wells will be converted to production over the next few months.

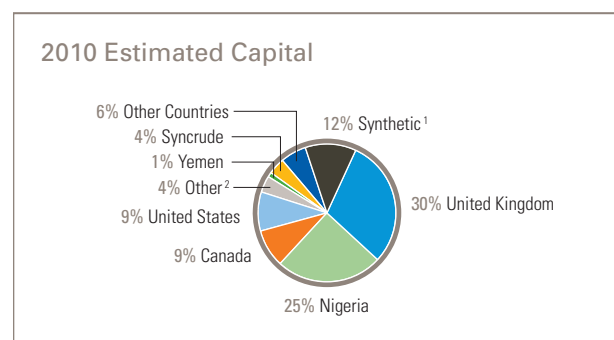
The reservoir is responding to consistent steaming, and bitumen production levels are increasing. Prior to the turnaround, which was completed late last year, we were only providing meaningful steam to about one-third of our 91 wells. These wells are providing the majority of our bitumen production, which averaged 13,600 bbls/d (gross) in the fourth quarter. The remaining wells have been cold for about a year and need to go through the circulation and ramp-up cycle.

We are currently producing approximately 18,000 bbls/d (gross) at an all-in steam-to-oil ratio (SOR) of approximately 6.0. This SOR includes steam to the wells that are in the steam-circulation stage and not yet producing bitumen and wells early in their ramp-up cycle. As our circulating wells start producing, we expect to see an increase in bitumen production rates with a corresponding decrease in SOR. The SOR of our producing wells is approximately 5.0 and includes well pairs recently converted to production that are in the early stages of ramp-up. We continue to expect a long-term SOR of 3.0 over the life of the project.



<sup>1</sup> Mainly Long Lake.

<sup>2</sup> Energy Marketing, Corporate and Other.



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<sup>2</sup> Energy Marketing, Corporate and Other.

We have achieved a number of major milestones at Long Lake over the past year. The facility is running as designed. The gasification process is working, creating a low-cost fuel source that reduces our need to purchase natural gas for operations. Post turnaround, the upgrader has processed approximately 90% of bitumen feedstock into the highest quality synthetic crude oil in North America. We continue to expect that we will ramp up to full rates and generate a significant margin advantage over our peers, even at current gas prices.

#### UNITED KINGDOM

We invested \$626 million in the UK North Sea last year including \$143 million on exploration activities. Our exploration program in the Golden Eagle area has generated discoveries at Golden Eagle, Pink and Hobby. To date, we have booked 50 mmboe of probable reserves (before royalties) for this area. We expect to book proved reserves as we advance the field development plan, which is progressing. We expect development will support standalone facilities and be economic with oil prices significantly lower than they are currently. We have a 34% interest in both Golden Eagle and Hobby and a 46% interest in Pink, and operate all three.

At Buzzard, we invested \$232 million, of which \$104 million related to the construction of the fourth platform, with the rest relating to ongoing development drilling. During the year, we added 22 mmboe of proved reserves here (before royalties). Fourteen mmboe are attributable to successful drilling and production performance, which resulted in increases in both reservoir size and recovery factor. The remaining eight mmboe relate to positive economic revisions associated with improved oil prices. In 2010, Buzzard will continue to be a significant contributor to our cash flow and production volumes.

At Ettrick, production was brought on stream last year and is expected to ramp up to approximately 20,000 boe/d (gross) in 2010. We also have a discovery at Blackbird that could be a future tie-back to Ettrick and plan to drill an appraisal well

here later this year. We have no proved reserves booked for Blackbird. We operate both Ettrick and Blackbird, with a 79.73% working interest in each.

At Scott/Telford, we added 12 mmboe of proved reserves (before royalties) largely as a result of successful development drilling at Telford, which allowed us to almost double our production from the Scott platform. We see further upside in the area with opportunities for quick tie-backs, and additional drilling is planned for 2010.

#### NIGERIA

Development of the Usan field, offshore West Africa, is progressing well, with first production expected in 2012. The development includes an FPSO with the ability to process 180,000 bbls/d (36,000 bbls/d, net to us) and store up to two million barrels of oil. In 2009, our capital investment here focused on fabrication of the FPSO hull and topside facilities, subsea equipment, development drilling and completion of detailed engineering and procurement. In 2010, we expect to complete fabrication of the FPSO hull and most of the topsides. In addition, we will continue fabrication of subsea components, development drilling and well completion activities. We have a 20% interest in exploration and development on this block and Total Exploration & Production Nigeria Limited is the operator.

We continue to explore offshore West Africa, and during the fourth quarter announced a successful exploration well at Owowo in the southern portion of Oil Prospecting License (OPL) 223. 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. The well reached a total depth of 2,227 metres and discovered several oil-bearing reservoirs containing light oil according to logs and other analysis. Under the production-sharing contract governing OPL 223, the Nigerian National Petroleum Corporation (NNPC) is concessionaire of the licence, which is operated by Total Exploration & Production Nigeria Limited. We have an 18% interest in the discovery.

## CANADA SHALE GAS

As conventional basins in Canada mature, we are focusing our investment on unconventional resource plays such as shale gas. In northeast British Columbia, we have a material shale gas position in the Horn River Basin with a 100% working interest. This play has the potential to be one of the most significant shale gas plays in North America. In 2009, we invested approximately \$214 million to drill, frac, complete and test wells, and build infrastructure. 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 this summer of 26 fracs in 15 days while achieving a 100% success rate on our frac program.

In 2010, we plan to build on this success by drilling an eight-well pad that will have longer horizontal wells with more fracs (18 fracs per well) than our earlier programs. The wells will be drilled this winter and then fraced and completed with production commencing in the second half of the year. We expect to achieve shale gas volumes from this program of approximately 50 mmcf/d in 2011. This program sets up a potential capital investment plan consisting of an 18-well pad that could commence drilling later in 2010. Further appraisal activity is required before we can establish commerciality and book reserves.

## SYNCRUDE

At Syncrude, we invested \$87 million in 2009 and converted seven mmbob of probable reserves to proved reserves. In 2010, a coker turnaround is scheduled in the third quarter and we expect annual production of between 19,000 and 24,000 bbls/d before royalties.

## UNITED STATES

In the Gulf of Mexico, our capital program is focused on the deep water and in 2009, we invested approximately \$64 million on our base shelf and deep-water producing assets.

We invested \$91 million to complete the development of Longhorn, which includes four subsea wells tied in to the ENI-operated Corral platform. Production is approaching peak rates in excess of 200 mmcf/d gross (50 mmcf/d, net to us). In 2009, we added two mmbob of proved reserves (before royalties). We have a 25% non-operated working interest in Longhorn, and ENI is the operator.

In the Eastern Gulf, we invested \$62 million on our exploration activities, which include the Antietam and Appomattox wells. The Antietam well encountered thick, good quality sand, but was non-commercial. Operations at Appomattox are ongoing and we are currently drilling a sidetrack well to further evaluate the prospect. Appomattox is located six miles west of our Vicksburg discovery. We have a 25% interest in Vicksburg and a 20% interest in Appomattox and Shiloh, an earlier discovery. To date, we have not booked any proved or probable reserves for these two discoveries. Shell Offshore Inc. operates all these Eastern Gulf wells.

Elsewhere in the deep water, we are drilling an appraisal well at Knotty Head with our contracted Ensco 8501 rig. The well spud in December and we expect results in the second quarter. To date, we have not booked any proved or probable reserves here. A second deep-water drilling rig is expected to arrive in mid 2010, which will allow us to start drilling more of our identified prospects.

## YEMEN

Yemen is an important asset for us and continues to generate cash flow in excess of capital requirements. In 2009, we invested \$69 million and added 12 mmbob of proved reserves (before royalties). We will continue to maximize the value of these assets over the remaining life of the contract and expect our 2010 annual production to average between 32,000 and 37,000 boe/d, before royalties. We are currently working with the Yemen government on a possible contract extension.

## CHEMICALS

We continued with the development of our technology conversion project (TCP) at our North Vancouver chlor-alkali plant. The TCP is providing technology and assets that are more cost-efficient and environmentally friendly than our current infrastructure. Project benefits are expected to include incremental annual operating cash flow of approximately \$40 million as a result of decreased production costs and increased plant capacity. The project is expected to start up in the second quarter of 2010 and should lower our cost structure and solidify our low-cost position in this regional market.

## FINANCIAL RESULTS

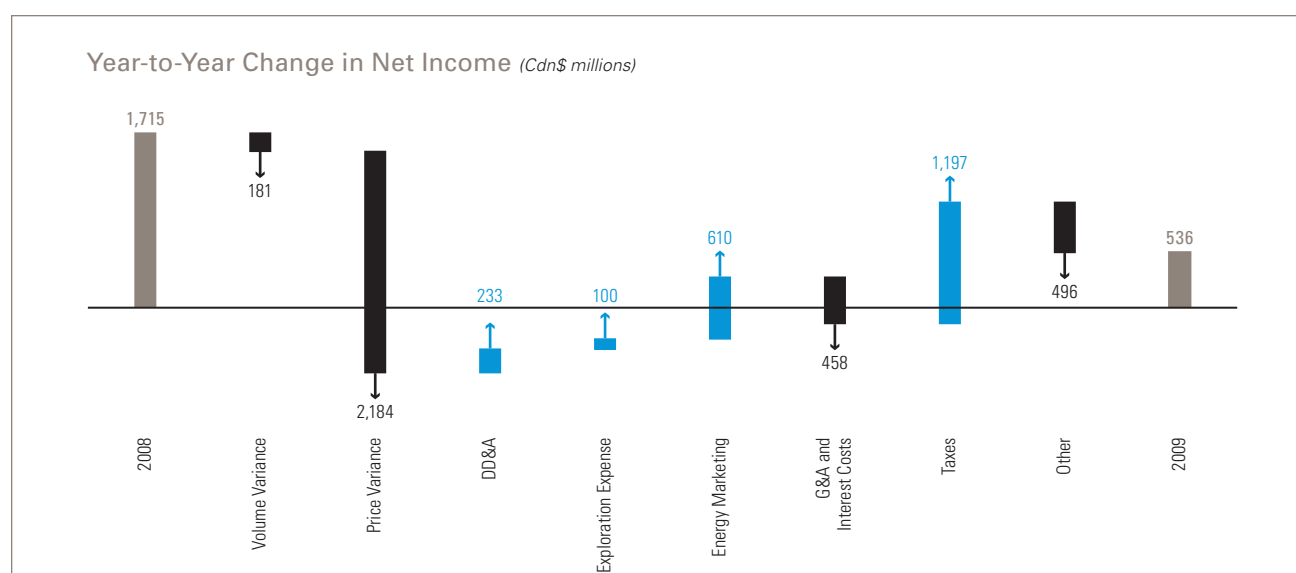
### Year-to-Year Change in Net Income

(Cdn\$ millions)

	2009 vs 2008	2008 vs 2007
<b>Net Income for 2008 and 2007</b>	<b>1,715</b>	<b>1,086</b>
Favourable (unfavourable) variances: <sup>1</sup>		
Production Volumes, After Royalties		
Crude Oil	(137)	40
Natural Gas	36	(22)
Change in Crude Oil Inventory	(80)	13
Total Volume Variance	(181)	31
Realized Commodity Prices		
Crude Oil	(1,871)	1,495
Natural Gas	(313)	119
Total Price Variance	(2,184)	1,614
Oil & Gas Operating Expense	9	(121)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas	241	(228)
Other	(8)	(19)
Total DD&A	233	(247)
Exploration Expense	100	(76)
Energy Marketing Revenue, Net	610	(424)
Chemicals Contribution	73	(76)
General and Administrative Expense	(240)	117
Interest Expense	(218)	74
Current Income Taxes	83	(425)
Future Income Taxes	1,114	(240)
Other		
Increase (Decrease) in Fair Value of Crude Oil Put Options	(454)	246
Other	(124)	156
<b>Net Income for 2009 and 2008</b>	<b>536</b>	<b>1,715</b>

<sup>1</sup> All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.



## OIL & GAS

### Production

	2009		2008		2007	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Oil and Liquids</b> (mmbbls/d)						
United Kingdom	98.0	98.0	99.7	99.7	81.2	81.2
Canada	14.6	11.4	16.2	12.3	17.1	13.4
Long Lake Bitumen <sup>2</sup>	7.9	7.9	3.9	3.9	–	–
Syncrude	20.2	18.6	20.9	18.2	22.1	18.8
United States	10.5	9.5	9.3	8.1	16.4	14.5
Yemen	49.9	29.8	56.6	30.6	71.6	39.8
Other Countries	3.5	3.2	5.8	5.3	6.2	5.7
	204.6	178.4	212.4	178.1	214.6	173.4
<b>Natural Gas</b> (mmcf/d)						
United Kingdom	24	24	18	18	16	16
Canada	139	128	131	109	118	98
United States	65	57	78	66	101	86
	228	209	227	193	235	200
<b>Total</b> (mboe/d)	<b>243</b>	<b>213</b>	<b>250</b>	<b>210</b>	<b>254</b>	<b>207</b>

- <sup>1</sup> We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.  
<sup>2</sup> We report bitumen as production until we are consistently operating the upgrader and producing Premium Synthetic Crude™.

#### 2009 VS 2008—LOWER VOLUMES DECREASED INCOME BY \$181 MILLION

Production before royalties was down 3% from 2008. Buzzard production was lower due to planned downtime for pipeline maintenance and to install the jacket of the fourth platform, as well as downtime to reinstall the Galaxy III drilling rig on location. This was partially offset by the start-up of the Ettrick field in the UK North Sea and Longhorn in the Gulf of Mexico. Bitumen production at Long Lake continues to ramp up as we increase steam to the field and bring on more wells. Our mature Yemen fields declined as expected but our after-royalty production volumes were consistent with the prior year as lower prices increased our share of net production under the cost-recovery arrangement.

Production after royalties increased slightly to average 213,000 boe/d, as higher margin barrels displaced higher royalty barrels.

The following table summarizes our production changes year over year:

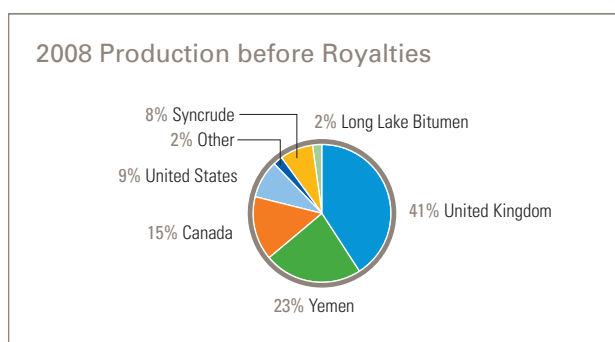
(mboe/d)	Before Royalties	After Royalties
<b>2008 Production</b>	<b>250</b>	<b>210</b>
<b>Production Changes</b>		
United Kingdom	(1)	(1)
Canada	–	2
Long Lake Bitumen	4	4
Syncrude	(1)	1
United States	(1)	–
Yemen	(6)	(1)
Other Countries	(2)	(2)
<b>2009 Production</b>	<b>243</b>	<b>213</b>

Fourth-quarter production averaged 265,000 boe/d (235,000 after royalties), 51,000 boe/d higher than the third quarter and 35,000 boe/d higher than the fourth quarter of 2008. The increase reflects resuming full production at Buzzard after successfully completing planned maintenance during the summer, ramping up of our new facilities at Ettrick and Longhorn, a successful step-out well at Telford and the ramp-up of Long Lake.

Production volumes discussed in this section represent our working interest before royalties.

## United Kingdom

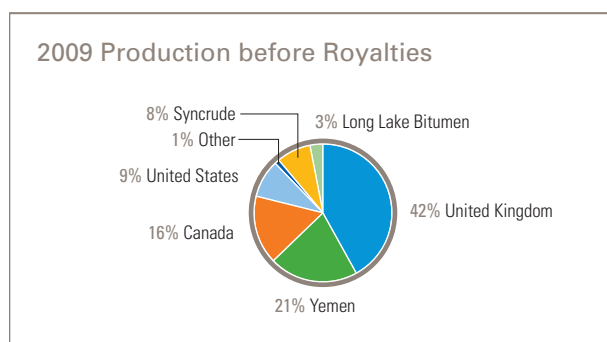
UK production for the year decreased slightly from 2008 to average 102,000 boe/d. Our share of Buzzard production averaged 81,400 boe/d (188,000 boe/d gross), down 8% from the prior year due to planned maintenance downtime midway through the year. In the second quarter, Buzzard production was shut-in for a week while the Galaxy III drilling rig was reinstalled on the platform. There were also four weeks of planned downtime in the third quarter, coinciding with a six-week slowdown of the Forties pipeline for routine maintenance. During this period, we successfully installed the jacket 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 2013. In the second quarter of 2010, we expect to install the topside facilities relating to the fourth platform onto the jacket. Based on our production experience to date, we anticipate that start-up of the platform will not be required until 2011. If advanced to 2010, downtime associated with the start-up could reduce annual volumes in 2010 by 10,000 to 15,000 boe/d.



At Scott/Telford, we averaged 13,500 boe/d, 29% higher than 2008 as a result of a successful step-out development well at Telford. This well was completed in the third quarter and is tied back to our Scott platform. Production from our non-operated fields at Duart and Farragon averaged 2,700 boe/d in 2009.

Production from the Ettrick field commenced in the third quarter, contributing 4,300 boe/d to our annual average volumes. We successfully produced at rates that allowed us to test the design capacity of the floating production, storage and offloading vessel (FPSO). Ettrick continues to ramp up as we complete safe commissioning of all systems. Our share of production averaged 11,400 boe/d in the fourth quarter. We have a nearby discovery at Blackbird that could be a future tie-back to Ettrick, further enhancing the economics of this development.

In 2010, we expect to drill an additional development well at Telford, which should add production volumes in the field. Additional development drilling is also planned at Ettrick, along with appraisal drilling at Blackbird. We expect production from the North Sea to average between 100,000 and 130,000 boe/d in 2010, taking into account expected downtime. Increases are expected to come from higher rates at Buzzard, ramp-up of Ettrick and additional successful development drilling at Telford.



On February 16th, we identified an item requiring repair to the separator unit on the Buzzard platform, which temporarily reduced production volumes to 30,000 to 50,000 boe/d (gross). Subsequently, production was restored to full rates of between 200,000 and 220,000 boe/d (86,000 and 95,000 boe/d, net to us).

## Canada

Production in Canada (excluding oil sands) remained consistent with the prior year. Slightly lower conventional production from our heavy oil properties was offset somewhat by higher coalbed methane (CBM) production rates. CBM production increased 20% from 2008 and averaged 51 mmcf/d. Natural declines on our heavy oil properties resulted in production decreasing 11% in 2009. Our natural gas production in the Medicine Hat region and Balzac was comparable with the previous year. In 2010, we expect our share of production from Canada to average between 28,000 and 34,000 boe/d. We recently identified a number of non-core assets for possible disposal, including our heavy oil assets in Western Canada. Production from our heavy oil properties averaged 16,800 boe/d in 2009.

### Long Lake

Bitumen production at Long Lake doubled from the prior year and averaged 7,900 boe/d (net to us) during 2009.

The higher production represents the continued ramp-up of production in response to increased steam volumes and more well pairs on production. During the year, the facility sold approximately 2,400 boe/d (net to us) of bitumen and 3,200 boe/d (net to us) of PSC™.

Our capital investment program in 2010 includes converting more existing wells from gas lift to electrical submersible pumping and drilling two sustaining well pads in accordance with our full field resource development plan. These pads are expected to be available to come on stream in late 2011. In 2010, annual bitumen production at Long Lake is expected to average between 20,000 and 30,000 boe/d (net to us).

### Syncrude

Syncrude production decreased 3% to average 20,200 boe/d during the year. Production in 2009 has been impacted by several factors including: i) a scheduled turnaround on Coker 8-3; ii) maintenance work on Coker 8-1; iii) fewer shipments of synthetic crude as a result of outages on the Pembina pipeline; and iv) unscheduled maintenance on both the vacuum distillation unit and the diluent recovery unit. In 2010, we expect to have one coker turnaround for routine maintenance and our share of production is expected to average between 19,000 and 24,000 boe/d.

### United States

Gulf of Mexico production volumes were 21,300 boe/d, 4% lower than 2008 due to declines in our mature shelf production. In the deep water, production remained consistent with the prior year. Production was higher at Aspen this year as production was shut-in during the fourth quarter of 2008 due to Hurricane Ike. When Aspen was brought back on stream, production rates were higher as a result of installing additional water-handling facilities on the third-party platform. Our non-operated Longhorn development commenced production late in 2009 and is approaching peak production of approximately 200 mmcf/d gross (50 mmcf/d, net to us). Current production is 37,000 boe/d gross (9,300 boe/d, net to us). Higher production volumes at Aspen and Longhorn were offset by Green Canyon 6, 50 and 137, which remain shut-in following Hurricane Ike. The third-party processing platform was destroyed during the hurricane last year and we are currently reviewing options to maximize the value of these fields.

Our shelf production decreased 1,200 boe/d, 12% below 2008 rates as a result of natural declines. During the year, we completed several successful recompletions and workovers to enhance performance; however, we are minimizing the capital invested in our mature shelf assets.

In 2010, we expect our share of production from the Gulf of Mexico to average between 20,000 and 28,000 boe/d.

### Yemen

In 2009, production from our Masila field declined 14% compared to last year and averaged 39,400 boe/d. This decline is consistent with our expectations as the field matures. We continue to target select infill development drilling opportunities due to the maturity of the field. During the year, we drilled 20 development wells as we concentrated our drilling program on maximizing reserve recoveries and economic returns, prior to the 2011 expiry of our contract. In 2010, we plan to drill up to 10 development wells. We are working with the Yemen government and our partners to potentially extend our production-sharing agreement for an additional five years beyond 2011. There is no assurance that this extension will be received.

Production at our East Al Hajr field on Block 51 decreased slightly from the prior year and averaged 10,500 boe/d for 2009. Successful well optimization and pressure maintenance somewhat offset natural declines.

Our oil and gas operations have operated as usual during the recent unrest in Yemen. Our production facilities are remote and located a significant distance from major population centres. We remain committed to operating in Yemen, focusing on the safety of our employees, contractors and facilities.

We expect our share of Yemen production to average between 32,000 and 37,000 boe/d in 2010.

### Other Countries

Production from Guando in Colombia decreased 40% to average 3,500 boe/d in 2009. The lower volumes reflect the reduced working interest in the Guando field effective in the second quarter of 2009. Under the terms of our licence, 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. We expect our share of production to average 2,000 boe/d in 2010.

## 2008 VS 2007—HIGHER NET PRODUCTION INCREASED INCOME BY \$31 MILLION

Production after royalties in 2008 was slightly higher than 2007. A full year of Buzzard production and increasing bitumen production at Long Lake offset declines at our maturing Yemen fields and hurricane interruptions in the US Gulf of Mexico. UK production was 22% higher than 2007 due primarily to a full year of production from Buzzard, which averaged 88,200 boe/d. This was offset somewhat by lower production at Scott/Telford resulting from higher than expected natural declines and increased downtime for maintenance.

Production in Canada (excluding oil sands) increased slightly in 2008, primarily as a result of increasing CBM volumes, offset somewhat by a decline in heavy oil production. Bitumen production at Long Lake averaged 3,900 boe/d (net to us) during 2008.

Our US production fell 33%, or about 11,000 boe/d from 2007, as hurricanes in the Gulf of Mexico temporarily shut-in production in the region. Prior to Hurricanes Gustav and Ike, we were producing approximately 30,000 boe/d. Production was reduced to 6,000 boe/d immediately after the hurricanes. Our properties at Gunnison, West Cameron and Eugene Island came back on stream during the fourth quarter, while production at Aspen, Wrigley and Green Canyon 6, 50 and 137 deep-water fields remained shut-in for the remainder of 2008. We exited 2008 producing approximately 12,000 boe/d.

At Syncrude, production decreased 5% from 2007 due to several factors, including: (i) two planned coker turnarounds and other maintenance; (ii) shutdown of the sulphur plant for maintenance; (iii) reduction in shipments of synthetic crude from outages in the Pembina pipeline; and (iv) shortage of bitumen supply as a result of production challenges in the mines.

## Commodity Prices

	2009	2008	2007
<b>Crude Oil</b>			
West Texas Intermediate (WTI) (US\$/bbl)	61.80	99.65	72.31
Dated Brent (Brent) (US\$/bbl)	61.51	96.99	72.52
Benchmark Differentials <sup>1</sup> (US\$/bbl)			
Heavy Oil	9.91	20.27	23.44
Mars	1.48	6.21	5.67
Masila	0.39	4.31	0.50
Realized Prices from Producing Assets (Cdn\$/bbl)			
United Kingdom	67.70	96.23	76.30
Canada	53.04	74.51	44.07
Syncrude	70.96	105.47	79.76
United States	65.01	104.94	69.83
Yemen	68.49	99.87	76.29
Other Countries	59.05	98.98	71.29
Corporate Average (Cdn\$/bbl)	66.85	96.92	73.43
<b>Natural Gas</b>			
New York Mercantile Exchange (US\$/mmbtu)	4.16	8.90	7.12
AECO (Cdn\$/mcf)	3.92	7.71	6.26
Realized Prices from Producing Assets (Cdn\$/mcf)			
United Kingdom	3.95	6.78	4.71
Canada	3.78	7.73	6.32
United States	4.67	10.07	7.80
Corporate Average (Cdn\$/mcf)	4.06	8.44	6.81
<b>Nexen's Average Realized Oil and Gas Price (Cdn\$/boe)</b>	<b>60.02</b>	<b>89.78</b>	<b>68.46</b>
Average Foreign Exchange Rate—Canadian to US Dollar	0.8757	0.9381	0.9304

<sup>1</sup> These differentials are a discount/(premium) to WTI.

## 2009 VS 2008—LOWER REALIZED PRICES DECREASED NET INCOME \$2,184 MILLION

Crude oil prices steadily increased during 2009, after falling dramatically in the fourth quarter of 2008 due to the economic crisis. WTI averaged US\$61.80/bbl for the year, down 38% from 2008, while Dated Brent decreased 37% to average US\$61.51/bbl over the same period. Gas prices fluctuated during the year, with NYMEX averaging US\$4.16/mmbtu and AECO averaging \$3.92/mcf, decreases of 53% and 49% from 2008, respectively. The impact of lower average commodity prices was partially offset by foreign exchange savings. Our corporate average crude oil price fell 31% to \$66.85/bbl, while our corporate average natural gas price was 52% lower, averaging \$4.06/mcf.

In 2009, the average annual US dollar was stronger than the Canadian dollar as compared to 2008. This reduced the impact of lower benchmark commodity prices, increasing net sales by approximately \$295 million. This impact on sales increased our realized crude oil and natural gas prices by approximately \$4.45/bbl and \$0.27/mcf, respectively.

### Crude Oil Reference Prices

During 2009, WTI prices were volatile and ranged from a low of US\$32.70/bbl to a high of US\$82.00/bbl, while averaging US\$61.80/bbl. WTI reached its low in February, recovering to US\$60/bbl by May and traded between US\$60/bbl and US\$80/bbl for the remainder of the year. Prices at the beginning of the year were driven by a weak global economy but increased later in the year as world economies responded to monetary and fiscal stimuli. The main drivers supporting crude oil prices were macro-related, including a continuing rally in US equity markets, positive investment flows into commodity markets in response to the weakening US dollar and more optimistic outlooks for global economic recovery.

Near-term demand/supply fundamentals have been slow to recover, with inventory levels and spare capacity remaining high. However, increases in oil demand from China and emerging markets has taken crude oil out of the Atlantic basin and is helping to balance the market and reduce inventory levels. Future demand growth is expected to come from these markets. A colder than normal winter also reduced inventory levels at the end of the year, which supported higher oil prices.

Economic indicators continue to be mixed and uncertainty remains about the sustainability of the recovery over the next few years. Coordinated monetary and fiscal policies have ended the recession in most countries, although much of the improvement in employment and GDP is being driven by unsustainable levels of public spending. A lasting global economic recovery is dependent on growth in Asia and the developing world and increased consumer spending in developed countries, which will be challenging due to high levels of unemployment, lower property values and a need to reduce consumer debt. The pace of the global recovery may be helped by China, which has significant cash reserves, low consumer debt and a high personal savings rate that could be reduced. China's growth may be slowed by government efforts to avoid creating a credit bubble.

Geopolitical events during the year such as concerns over Iran's nuclear enrichment program, military action in Nigeria, the ongoing wars in Iraq and Afghanistan and requests for greater regulation of energy markets and futures trading seemed to have little impact on price due to spare capacity and high inventory levels. However, a much tighter supply/demand environment is expected to emerge in 2010. With minimal growth forecast in non-OPEC supply, oil demand growth is expected to reduce inventory levels and OPEC spare capacity. This will increase price sensitivity to geopolitical events.

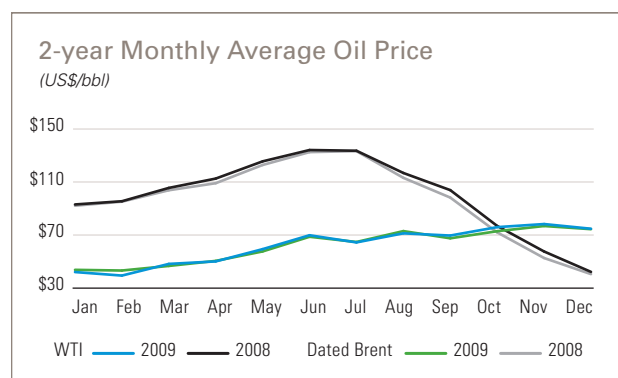
### Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US\$9.91/bbl (16% of WTI) for the year, compared to US\$20.27/bbl (20% of WTI) in 2008. The heavy oil differential continued to be narrower than historic levels due to cuts in low/medium-quality crude oil production quotas by OPEC, strong fuel oil prices and lower heavy oil supply from Mexico and Venezuela. Excess refinery capacity increased the demand for heavy oil and also contributed to the narrower differential.

The Brent/WTI differential strengthened during 2009, with Brent trading at a discount of only US\$0.29/bbl compared to US\$2.66/bbl in 2008. The Brent/WTI differential was volatile during the year. Initially, Brent was at a premium to WTI 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 year, the differential reverted to a discount.

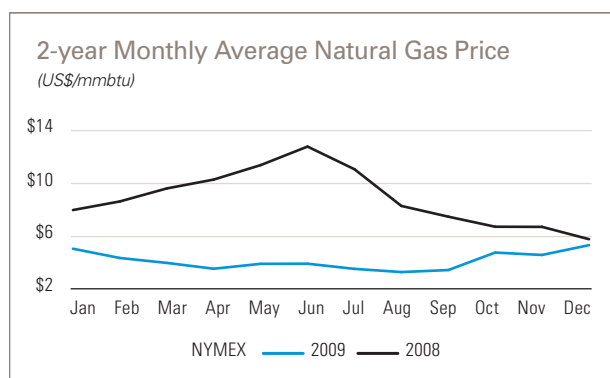
The US Gulf Coast Mars differential narrowed during the year, averaging US\$1.48/bbl in 2009 compared with US\$6.21/bbl in 2008. This was due to high inventory levels at Cushing as a portion of production from the Gulf of Mexico was sent overseas, rather than into an oversupplied onshore market. The differential also narrowed due to OPEC cuts in medium crude.

The Yemen Masila differential narrowed during the year, averaging US\$0.39/bbl in 2009 compared with US\$4.31/bbl in 2008. The Masila price strengthened relative to both WTI and Brent, reflecting strong demand from China and other Asian countries that are the primary buyers of Masila Crude. High Cushing inventory levels also contributed to the narrower Yemen Masila differential to WTI.



### Natural Gas Reference Prices

Low NYMEX natural gas 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. Market fears of reaching maximum gas storage well before the withdrawal season resulted in low prices for most of the year. Supply in North America has been impacted by the growth in unconventional gas and increased productivity through technological advances in horizontal drilling and fracturing techniques. Cold weather in late 2009 increased prices and reduced a portion of the inventory surplus. However, continuing weak gas prices are forecasted as strong supply additions are expected from shale gas, tight gas and new LNG volumes imported from Russia and the Middle East.



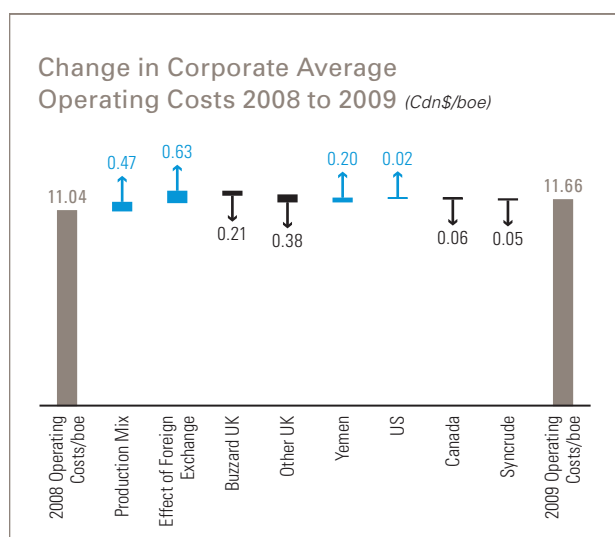
### 2008 VS 2007—HIGHER REALIZED PRICES INCREASED NET INCOME \$1,614 MILLION

In 2008, commodity prices reached record highs but declined significantly in the fourth quarter. WTI averaged US\$99.65/bbl for the year, 38% higher than 2007, while Dated Brent increased 34% over the same period. Our average realized crude oil price increased 32% from \$73.43/bbl to \$96.92/bbl. During the year, NYMEX gas price increased 25% and AECO increased 23%, averaging US\$8.90/mmbtu and \$7.71/mcf, respectively. During the same period, our corporate average realized gas price increased 24% to \$8.44/mcf, as our gas sales are primarily based off of NYMEX and AECO prices. Compared to 2007, the US dollar weakened relative to the Canadian dollar. As a result, our realized crude oil and natural gas price decreased by approximately \$0.80/bbl and \$0.07/mcf, respectively, and our net sales were lower by approximately \$56 million.

## Operating Expenses

(Cdn\$/boe)	2009		2008		2007	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Conventional Oil and Gas</b>						
United Kingdom	6.87	6.87	6.75	6.75	6.94	6.94
Canada	12.76	14.80	13.12	16.38	12.91	15.93
United States	12.58	14.10	11.57	13.48	8.43	9.69
Yemen	10.69	18.34	8.51	15.88	6.56	12.00
Other Countries	6.03	6.53	4.52	4.91	3.45	3.76
Average Conventional	9.34	10.76	8.68	10.40	7.89	9.75
<b>Synthetic Crude Oil</b>						
Syncrude	35.92	39.09	36.53	42.04	25.80	30.32
<b>Average Oil and Gas</b>	<b>11.66</b>	<b>13.33</b>	<b>11.04</b>	<b>13.18</b>	<b>9.45</b>	<b>11.63</b>

<sup>1</sup> 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.



### 2009 VS 2008—LOWER OPERATING EXPENSES INCREASED NET INCOME BY \$9 MILLION

Our average oil and gas operating cost increased \$0.62/boe from 2008 as lower costs in Canada and Syncrude were only partially offset by the impact of a stronger US dollar in other areas. US-dollar-denominated operating costs were higher when translated to Canadian dollars, increasing our corporate average by \$0.63/boe for 2009.

Changes in our production profile during the year increased our corporate average by \$0.47/boe. Buzzard, a lower cost area, contributed a smaller percentage of our total production compared to higher cost areas such as Scott/Telford and Ettrick.

In the UK North Sea, lower production rates at Buzzard were more than offset by reduced operating costs due to higher planned downtime and lower production tariffs and logistics costs. This reduced our corporate average by \$0.21/boe. The impact of other areas in the UK North Sea reduced our corporate average by \$0.38/boe. At Scott/Telford, total costs decreased while production was higher due to additional Telford production. This was somewhat offset by the start-up of the Ettrick field and FPSO, where operating costs per barrel are higher than our corporate average.

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 \$0.20/boe. In the US Gulf of Mexico, slightly higher operating costs, combined with lower shelf production, increased our corporate average by \$0.02/boe.

Canada reduced our corporate average by \$0.06/boe as lower heavy oil and CBM costs were substantially offset by increased operating costs at Balzac. Our heavy oil properties experienced improved run times and less downtime, which reduced downhole workover costs. This, combined with lower utility costs, reduced operating costs by 14%. CBM costs increased as we brought more wells on stream; however, the incremental production volumes reduced our average cost per barrel. This was partially offset by increased per-unit cost at Balzac, where the impact of declining production has only partially been offset by lower operating costs.

At Syncrude, operating costs decreased as lower natural gas costs were partially offset by higher maintenance costs. The lower operating costs reduced our corporate average by \$0.05/boe. Costs at Long Lake are capitalized as development costs until we reach commercial operations, which is expected to occur in the first quarter of 2010.

#### **2008 VS 2007—HIGHER OPERATING EXPENSES DECREASED NET INCOME BY \$121 MILLION**

Overall, operating costs increased 14% from 2007, primarily due to the low-cost Buzzard field being on stream for the full year and higher expenditures at Syncrude. Our production mix also changed from the previous year as additional Buzzard volumes were offset by lower volumes in Yemen and the US Gulf of Mexico. Changes in our production profile reduced our corporate average by \$0.35/boe, as Buzzard has lower operating costs per barrel.

In the UK North Sea, operating costs increased 19%. The increase was attributable to a full year's production at Buzzard, compared to 2007, when we were ramping up production. In addition, transportation costs increased from higher volumes and increased tariff charges. Elsewhere in the UK North Sea, operating costs increased while production declined, increasing our corporate average by \$0.45/boe. The majority of the cost increase was due to platform maintenance at Scott/Telford, including: i) additional diesel costs for turbine repairs, ii) maintenance on our water injection and power generation facilities and iii) subsea maintenance.

In Yemen, Masila and Block 51 increased our corporate average by \$0.32/boe and \$0.21/boe, respectively, as a result of lower production rates. Our operating costs were focused on service rig activity and maintenance programs for existing wells. In the US Gulf of Mexico, operating costs were 8% lower than 2007; however, lower production as a result of the hurricanes increased the average unit cost by \$0.30/boe.

Operating costs in Canada were marginally higher than in 2007. Costs in our heavy oil operations increased as a result of higher salaries, utilities and trucking costs. While CBM costs were slightly higher as the number of producing wells increased, the incremental volumes reduced our average cost per barrel. At our natural gas properties, a combination of increased downhole activity and surface maintenance resulted in higher operating costs. These increases were offset by lower costs at our Balzac gas plant, which had a turnaround in the previous year.

Syncrude operating costs were \$72 million or 35% higher than 2007 and increased our corporate average by \$0.91/boe. A number of factors contributed to the higher operating costs, including: i) higher contracting costs to increase the mineable ore inventory for bitumen supply; ii) purchasing additional third-party bitumen to upgrade; iii) higher natural gas prices in the first half of 2008; and iv) unscheduled and extended maintenance.

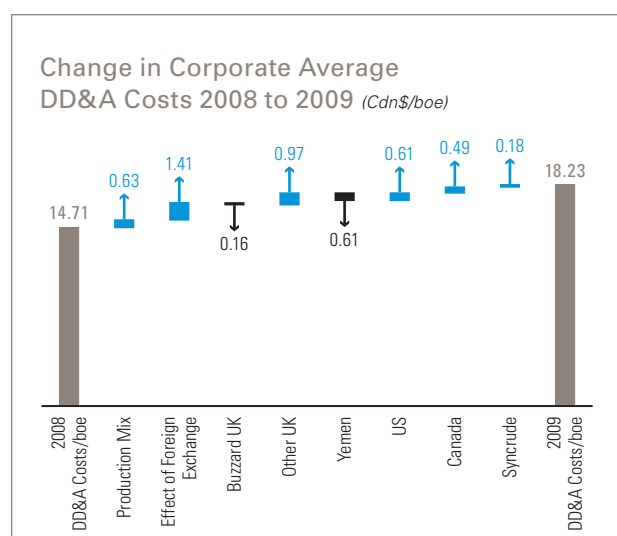
US-dollar-denominated operating costs were lower when translated to Canadian dollars as a result of the weaker US dollar for the majority of 2008. This decreased our corporate average by \$0.23/boe.

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

(Cdn\$/boe)	2009		2008		2007	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Conventional Oil and Gas<sup>2</sup></b>						
United Kingdom	22.42	22.42	17.72	17.72	19.59	19.59
Canada	18.12	21.03	14.99	18.71	12.46	15.37
United States	37.64	42.18	27.46	31.97	22.64	26.03
Yemen	5.75	9.87	7.75	14.45	8.15	14.92
Other Countries	11.16	12.08	7.90	8.58	3.68	4.06
Average Conventional	19.16	22.09	15.48	18.54	14.94	18.47
<b>Synthetic Crude Oil</b>						
Syncrude	8.46	9.20	6.39	7.35	6.59	7.74
<b>Average Oil and Gas</b>	<b>18.23</b>	<b>20.90</b>	<b>14.71</b>	<b>17.56</b>	<b>14.21</b>	<b>17.49</b>

<sup>1</sup> 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.

<sup>2</sup> DD&A per boe excludes the impairment charges described in Note 4 of our Consolidated Financial Statements.



### 2009 VS 2008—LOWER OIL AND GAS DD&A INCREASED NET INCOME BY \$241 MILLION

Our corporate average DD&A cost per barrel increased \$3.52/boe from 2008. The stronger US dollar increased our corporate average by \$1.41/boe as depletion of our international and US assets is denominated in US dollars, while changes in our production profile also increased our corporate average by \$0.63/boe. The change in our production mix was primarily a result of: i) slightly lower Buzzard production, where our DD&A rate is low and ii) higher production volumes at Scott/Telford and Ettrick, where we have higher than average DD&A rates. We incurred non-cash impairment charges of \$78 million in the fourth

quarter at three natural gas properties in Canada and the US. Our year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices.

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 total corporate average by \$0.16/boe. Elsewhere in the UK, higher depletion rates at Ettrick and Scott/Telford increased our corporate average by \$0.97/boe. The Ettrick depletion rate is higher than our average as a result of higher development costs. The Scott/Telford fields' depletion rate increased compared to 2008 as a result of downward price-related reserve revisions at the end of 2008. Our DD&A expense also includes \$49 million for our Perth prospect in the North Sea, where we expensed allocated acquisition costs as we are unlikely to proceed with development of this prospect.

Lower depletion rates in Yemen, due to lower capital expenditures from drilling fewer development wells and higher reserve estimates, reduced our corporate average by \$0.61/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 \$0.61/boe.

Canadian depletion increased our corporate average by \$0.49/boe. Depletion rates at our heavy oil properties increased 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.

Syncrude incurred an additional depletion expense of \$14 million in the fourth quarter related to the replacement of an asset that was previously damaged at the upgrading facilities. This increased Syncrude's DD&A rate by \$1.95/boe for the year and increased our corporate average by \$0.18/boe. Excluding the impact of the additional depletion expense, Syncrude DD&A rate was consistent with the prior year.

#### **2008 VS 2007—HIGHER OIL AND GAS DD&A DECREASED NET INCOME BY \$228 MILLION**

During the fourth quarter of 2008, we recorded non-cash impairment charges of \$568 million primarily related to properties in the UK North Sea and the Gulf of Mexico. In the North Sea, we recognized an impairment charge of \$318 million relating to our Selkirk and Ettrick properties. At Selkirk, we expensed \$62 million of allocated acquisition costs as we had no firm development plans. At Ettrick, the impairment charge largely reflected higher costs and lower reserve estimates. In the Gulf of Mexico, our impairment charge related to four shelf properties (\$143 million) and our Green Canyon 6 deep-water property (\$107 million). The shelf properties that were impaired were late-life, mature assets that were sensitive to near-term commodity prices. At Green Canyon 6, the impairment expense reflected higher costs after Hurricane Ike destroyed a third-party production

platform in the third quarter of 2008. This resulted in unexpected costs to construct new production facilities.

In the UK, our DD&A expense increased 14% over 2007 as a result of additional production from Buzzard. The impact of higher production was offset by a lower DD&A rate at Buzzard with the addition of new reserves at the beginning of 2008. The lower depletion rate at Buzzard decreased our corporate average rate by \$0.74/boe. Elsewhere in the UK, our depletion rate increased at our mature Scott/Telford and smaller Farragon fields, increasing our corporate average by \$0.47/boe.

In the Gulf of Mexico, reserve revisions at the end of 2007 resulted in higher depletion rates in 2008 and increased our corporate average unit cost by \$0.59/boe.

Depletion of our Canadian assets increased our corporate average rate by \$0.38/boe and was primarily due to our CBM projects in central Alberta. During 2008, we invested capital in new wells and facilities. A difference exists between the timing of capital expenditures and the recognition of the reserves. This delay resulted in high initial depletion rates for our CBM projects.

In Colombia, our depletion rate doubled from 2007, a result of increased capital costs and lower reserve estimates. This increased our corporate average rate by \$0.10/boe.

The stronger Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by \$0.45/boe as our US and international depletion is denominated in US dollars.

## Exploration Expense

<i>(Cdn\$ millions)</i>	2009	2008	2007
Seismic	81	137	123
Unsuccessful Drilling	115	203	126
Other	106	62	77
<b>Total Exploration Expense</b>	<b>302</b>	<b>402</b>	<b>326</b>
New Growth Exploration	582	582	573
Geological and Geophysical Costs	81	137	123
<b>Total Exploration Expenditures</b>	<b>663</b>	<b>719</b>	<b>696</b>
Exploration Expense as a % of Exploration Expenditures	46%	56%	47%

### 2009 VS 2008—LOWER EXPLORATION EXPENSE INCREASED NET INCOME BY \$100 MILLION

Exploration expenditures decreased \$56 million from last year as we focused our capital on the US Gulf of Mexico, the North Sea and shale gas in Canada. Exploration expense decreased 25% over the same period due to more successful exploration wells in 2009 and lower seismic data acquisition costs.

In the UK, we had 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. In total, we have drilled three exploration and eleven appraisal wells here. We are evaluating development options for the Golden Eagle area as we continue project appraisal.

We drilled a successful 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 east of the Usan field, currently under development. The well reached a total depth of 2,227 metres and discovered several oil-bearing reservoirs.

In the Eastern Gulf of Mexico, operations at Appomattox are ongoing and we are currently drilling a sidetrack well to further evaluate the prospect. Appomattox is located six miles west of our Vicksburg discovery. We are also currently drilling an appraisal well at Knotty Head and results are expected in 2010. The well is being drilled by our first contracted deep-water rig, the Ensco 8501.

We continue to make significant progress on our shale gas project in the Dilly Creek area of the Horn River Basin in northeast British Columbia, where we have approximately

90,000 acres with a 100% working interest. During the year, we completed a drilling and completion program and realized substantial cost savings and productivity improvements. We now have five shale gas wells on stream and achieved first month average rates of over 15 mmcf/d in 2009.

Unsuccessful drilling expense during the year includes expensing CBM drilling costs in Canada and unsuccessful wells in the Eastern Gulf of Mexico and UK North Sea.

In Canada, we expensed costs of \$49 million related to our CBM exploration activities in central Alberta on properties where we currently have no future firm development plans. In the Eastern Gulf of Mexico, the Antietam well encountered thick, good-quality sand, but was non-commercial and subsequently plugged and abandoned, resulting in expensing costs of \$31 million. We also chose not to proceed with the development of a small discovery at Green Canyon 448 and accordingly expensed \$14 million.

During 2009, seismic data acquisition costs were \$56 million lower than 2008 when we purchased significant seismic data associated with newly acquired blocks in the Norwegian North Sea. Seismic data costs will fluctuate depending on the level of our evaluation activities stage.

### 2008 VS 2007—HIGHER EXPLORATION EXPENSE REDUCED NET INCOME BY \$76 MILLION

Our total exploration expenditures increased \$23 million from 2007. In 2008, we focused our investment on exploratory drilling in the US Gulf of Mexico, UK North Sea and CBM in Canada and on acquiring seismic data in Norway. Exploration expense increased 23% over the same period due to higher seismic data acquisitions and unsuccessful exploration wells.

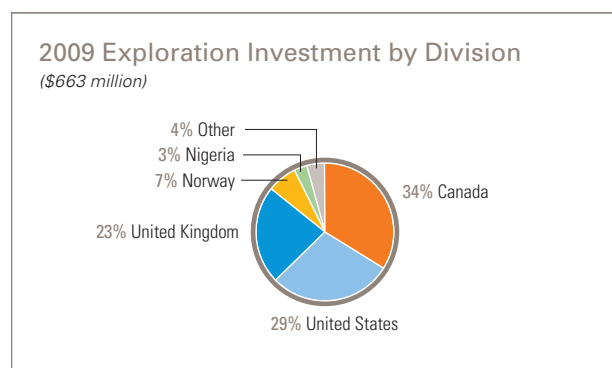
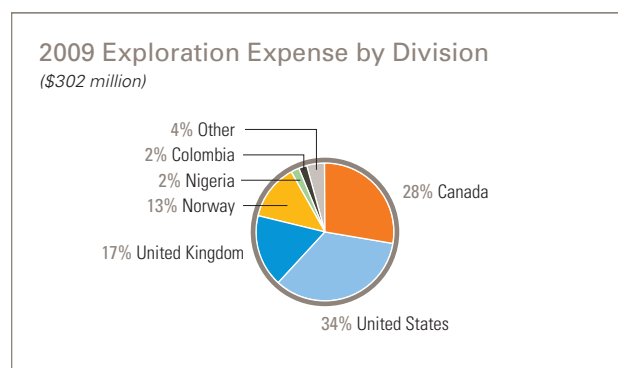
In the Gulf of Mexico, we drilled a successful deep-water exploration well early in 2008 at Mississippi Canyon 72. Elsewhere in the deep water, we drilled two unsuccessful wells. At Fredericksburg, we drilled to a depth of 24,560 feet but failed to encounter commercial hydrocarbons. This well was subsequently abandoned and \$24 million in exploration costs were written off. Our unsuccessful exploration well at Sapphire resulted in a \$28 million expense.

In the UK North Sea, we had successes at Blackbird, Pink, Bugle and Rochelle. Blackbird is located 6 km south of Ettrick and production could be tied in to the Ettrick FPSO, following additional appraisal drilling and development evaluation. At Pink, we drilled a successful exploration well and sidetrack. Early in 2009, we completed drilling a successful appraisal well at Rochelle, where we have a 44% non-operated interest. Rochelle is located approximately

20 km south of the Scott/Telford fields. During 2008, we drilled a dry hole at Full Moon, which cost \$16 million, and we expensed \$32 million of drilling costs for our Selkirk prospect, which we do not plan to develop.

In Canada, we expensed \$67 million for unsuccessful CBM exploration in Alberta. The costs related to our CBM exploration activities in central Alberta, where we have no future development plans.

During 2008, seismic data acquisition costs were 11% higher than 2007. Norway seismic acquisitions increased 47% during 2008 as we obtained data on newly acquired blocks in the Norwegian North Sea. In the US Gulf of Mexico, our seismic investment decreased from 2007 as we focused on analyzing seismic data acquired in previous years. Elsewhere, we acquired seismic data in the UK North Sea, Nigeria and Colombia.



## OIL & GAS NETBACKS

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. Our margins improved 26% over the last five years. Our cash netbacks are 64% of realized sales prices in 2009. This is caused by transitioning our production to lower royalty jurisdictions.

	2009	2008	2007	2006	2005
Realized Sales Price	60.02	89.78	68.46	62.92	57.97
Cash Netback	38.55	60.64	43.22	32.75	30.57
Cash Netback as % of Realized Sales Price	64%	68%	63%	52%	53%

The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

## Before Royalties<sup>1</sup>

	2009						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	65.93	34.58	70.96	46.27	68.49	59.05	60.02
Royalties and Other	–	(5.75)	(6.04)	(4.89)	(28.94)	(4.52)	(8.06)
Operating Expenses	(6.87)	(12.76)	(35.92)	(12.58)	(10.69)	(6.03)	(11.66)
In-country Taxes <sup>2</sup>	–	–	–	–	(8.31)	–	(1.75)
<b>Cash Netback</b>	<b>59.06</b>	<b>16.07</b>	<b>29.00</b>	<b>28.80</b>	<b>20.55</b>	<b>48.50</b>	<b>38.55</b>

	2008						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	94.45	58.34	105.47	79.02	99.87	98.98	89.78
Royalties and Other	–	(12.25)	(15.11)	(11.03)	(46.94)	(7.88)	(15.06)
Operating Expenses	(6.75)	(13.12)	(36.53)	(11.57)	(8.51)	(4.52)	(11.04)
In-country Taxes <sup>2</sup>	–	–	–	–	(13.31)	–	(3.04)
<b>Cash Netback</b>	<b>87.70</b>	<b>32.97</b>	<b>53.83</b>	<b>56.42</b>	<b>31.11</b>	<b>86.58</b>	<b>60.64</b>

	2007						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	74.79	40.79	79.76	58.16	76.29	71.29	68.46
Royalties and Other	–	(7.81)	(12.02)	(7.45)	(34.69)	(5.90)	(13.10)
Operating Expenses	(6.94)	(12.91)	(25.80)	(8.43)	(6.56)	(3.45)	(9.45)
In-country Taxes <sup>2</sup>	–	–	–	–	(9.52)	–	(2.69)
<b>Cash Netback</b>	<b>67.85</b>	<b>20.07</b>	<b>41.94</b>	<b>42.28</b>	<b>25.52</b>	<b>61.94</b>	<b>43.22</b>

## After Royalties<sup>1</sup>

	2009						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	65.93	34.58	70.96	46.27	68.49	59.05	60.02
Operating Expenses	(6.87)	(14.80)	(39.09)	(14.10)	(18.34)	(6.53)	(13.33)
In-country Taxes <sup>2</sup>	–	–	–	–	(14.26)	–	(2.00)
<b>Cash Netback</b>	<b>59.06</b>	<b>19.78</b>	<b>31.87</b>	<b>32.17</b>	<b>35.89</b>	<b>52.52</b>	<b>44.69</b>

	2008						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	94.45	58.34	105.47	79.02	99.87	98.98	89.78
Operating Expenses	(6.75)	(16.38)	(42.04)	(13.48)	(15.88)	(4.91)	(13.18)
In-country Taxes <sup>2</sup>	–	–	–	–	(24.83)	–	(3.63)
<b>Cash Netback</b>	<b>87.70</b>	<b>41.96</b>	<b>63.43</b>	<b>65.54</b>	<b>59.16</b>	<b>94.07</b>	<b>72.97</b>

	2007						
(\$/boe)	UK	Canada	Syncrude	US	Yemen	Other	Total
Sales	74.79	40.79	79.76	58.16	76.29	71.29	68.46
Operating Expenses	(6.94)	(15.93)	(30.32)	(9.69)	(12.00)	(3.76)	(11.63)
In-country Taxes <sup>2</sup>	–	–	–	–	(17.42)	–	(3.31)
<b>Cash Netback</b>	<b>67.85</b>	<b>24.86</b>	<b>49.44</b>	<b>48.47</b>	<b>46.87</b>	<b>67.53</b>	<b>53.52</b>

<sup>1</sup> Before royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

<sup>2</sup> Comprises income taxes payable in Yemen that are included in the government's share of profit oil.

## ENERGY MARKETING

<i>(Cdn\$ millions)</i>	2009	2008	2007
Physical Sales <sup>1</sup>	41,093	54,772	34,358
Physical Purchases <sup>1</sup>	(40,145)	(54,047)	(33,417)
Net Financial Transactions <sup>1,2</sup>	(171)	(142)	(61)
Change in Fair Market Value of Inventory <sup>1</sup>	166	(116)	79
<b>Marketing Revenue</b>	<b>943</b>	<b>467</b>	<b>959</b>
Transportation Expense	(600)	(751)	(806)
Other	5	27	14
<b>Net Marketing Revenue</b>	<b>348</b>	<b>(257)</b>	<b>167</b>
<b>Contribution to Net Marketing Revenue by Region</b>			
North America	318	(284)	151
Asia	23	13	11
Europe	7	14	5
<b>Net Marketing Revenue</b>	<b>348</b>	<b>(257)</b>	<b>167</b>
Depreciation, Depletion, Amortization and Impairment	(27)	(19)	(13)
General and Administrative	(91)	(79)	(87)
Allowance for Doubtful Receivables	5	(54)	–
<b>Marketing Contribution to Income before Income Taxes</b>	<b>235</b>	<b>(409)</b>	<b>67</b>
<b>North America</b>			
<b>Natural Gas</b>			
Physical Sales Volumes <sup>3</sup> (bcf/d)	4.9	6.7	5.8
Transportation Capacity (bcf/d)	1.5	1.8	2.0
Storage Capacity <sup>4</sup> (bcf)	32	38	39
Financial Volumes <sup>5</sup> (bcf/d)	10.1	16.8	21.9
<b>Crude Oil</b>			
Physical Sales Volumes <sup>3</sup> (mmbbls/d)	852	656	655
Storage Capacity <sup>4</sup> (mmbbls)	3,030	2,578	2,734
Financial Volumes <sup>5</sup> (mmbbls/d)	730	1,591	2,134
<b>Power</b>			
Physical Sales Volumes <sup>3</sup> (GWhrs/d)	10	5	5
Generation Capacity (MW/hr)	87	87	87
<b>Asia</b>			
Physical Sales Volumes <sup>3</sup> (mmbbls/d)	94	99	120
Financial Volumes <sup>5</sup> (mmbbls/d)	384	349	256
<b>Europe</b>			
Financial Volumes <sup>5</sup> (mmbbls/d)	378	787	529
<b>Value-at-Risk</b>			
Year End	11	25	26
High	24	40	38
Low	9	19	24
Average	15	30	30

1 Energy marketing's physical sales, physical purchases, net financial transactions and changes in fair market value of inventory are reported net on the Consolidated Statement of Income as marketing and other income.

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 year.

4 Energy marketing's storage capacity reflects volumes contracted but not necessarily used at all times.

5 Financial volumes represent amounts largely acquired to economically hedge physical transactions during the year.

### **2009 VS 2008—HIGHER CONTRIBUTIONS FROM ENERGY MARKETING INCREASED NET INCOME BY \$610 MILLION**

Energy marketing generated \$348 million in net revenue in 2009, with all businesses contributing positive results. We renewed focus on the physical producer/marketer model, which involves buying, selling and holding physical commodities and holding the rights to physical transportation and storage assets.

During the fourth quarter, energy marketing continued to optimize its trading around physical assets, resulting in gains on physical positions and commodity inventory, together with gains from blending in our crude oil business. During the latter part of 2009, gas prices increased as a result of cold weather across North America, resulting in unrealized gains on inventory, which is carried at fair value. We also had gains on derivatives used to hedge our transportation assets.

The largest contribution in 2009 came from our global crude oil business, which generated gains by inventory management and physical business as a result of contango in the forward price curve. These gains were recognized largely in the first quarter of 2009. This contango, combined with narrowing crude oil differentials, enabled us to capture both realized and unrealized gains on our relatively low-risk physical trading strategies.

Similar to 2008, the natural gas business faced a challenging economic environment. Gas prices remained suppressed while location spreads between markets continued to narrow throughout the year. Early in the year, the gas business incurred losses as a result of exiting the last of its trading positions from 2008 and from selling natural gas inventory where the offsetting gains on the financial instruments hedging the inventory were recognized in prior periods. Weakness in gas markets reduced the value of holding transportation capacity. Any losses associated with the transportation and storage capacity contracts will be recognized when the contracts are used or sold.

During the year, 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. In early 2010, we entered into an agreement to sell our European gas and power marketing business.

### **2008 VS 2007—REDUCED ENERGY MARKETING NET REVENUE DECREASED NET INCOME BY \$424 MILLION**

Our 2008 results were impacted by the significant volatility in commodity markets, the dramatic decrease in commodity prices and markets that operated outside normal historical fundamentals. Losses in 2008 were largely from our North America gas team, who were positioned to take advantage of differentials between locations and capture value between summer and winter prices. The rapidly deteriorating economic environment resulted in dramatic demand destruction. In mid 2008, we refocused on optimizing the physical business and the team began to exit positions, thereby incurring losses due to the lack of liquidity in the market and falling commodity prices.

The credit crisis that impacted financial markets caused some of our counterparties to restructure or declare bankruptcy. In September 2008, Lehman Brothers filed for bankruptcy protection and our exposure to them in our trading operations was approximately \$39 million. The entire amount was expensed in the third quarter of 2008, although we continue to pursue recovery of these amounts. We also provided an additional \$15 million for credit risk with our counterparties. The majority of our counterparties are integrated oil companies, crude oil refiners and marketers, and large utilities.

Results from our marketing group vary between periods, and historical results are not necessarily indicative of future results. 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 economically hedge these assets.

## COMPOSITION OF NET MARKETING REVENUE

<i>(Cdn\$ millions)</i>	2009	2008	2007
Trading Activities (Physical and Financial)	339	(287)	147
Other Activities	9	30	20
<b>Total Net Marketing Revenue</b>	<b>348</b>	<b>(257)</b>	<b>167</b>

### TRADING ACTIVITIES

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts using fair value accounting and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

### OTHER ACTIVITIES

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

### Fair Value of Derivative Contracts

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net short position and the bid price when we have a net long position. This adjustment reflects an estimated exit price and incorporates the impact of liquidity when the bid-ask spread

widens in less liquid markets. We incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

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

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

At December 31, 2009, the fair value of our derivative contracts in our energy marketing trading activities totaled \$23 million. This includes contracts used to economically hedge our physical storage and transportation contracts that cannot be carried at fair value until they are used. Below is a breakdown of the derivative fair value by valuation method and contract maturity.

(Cdn\$ millions)	Maturity				Total
	< 1 year	1–3 years	4–5 years	> 5 years	
Level 1—Actively Quoted Markets	(68)	(61)	(14)	–	(143)
Level 2—Based on Other Observable Pricing Inputs	56	52	10	6	124
Level 3—Based on Unobservable Pricing Inputs	22	20	–	–	42
<b>Fair Value at December 31, 2009</b>	<b>10</b>	<b>11</b>	<b>(4)</b>	<b>6</b>	<b>23</b>

### Changes in Fair Value of Derivative Contracts

(Cdn\$ millions)	Total
Fair Value at December 31, 2008	63
Change in Fair Value of Contracts	142
Net Losses (Gains) on Contracts Closed	(182)
Changes in Valuation Techniques and Assumptions <sup>1</sup>	–
<b>Fair Value at December 31, 2009</b>	<b>23</b>

<sup>1</sup> Our valuation methodology has been applied consistently 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 1.2 years.

## CHEMICALS

(Cdn\$ millions)	2009	2008	2007
Net Sales	458	477	414
Sales Volumes (thousand short tons)			
Sodium Chlorate	441	495	478
Chlor-alkali	447	469	465
Operating Profit <sup>1</sup>	143	125	118
Operating Margin <sup>2</sup>	31%	26%	29%
Chemicals Contribution to Income Before Income Taxes <sup>3</sup>	79	(14)	64
Capacity Utilization	88%	92%	94%

<sup>1</sup> Net sales less operating costs, transportation and other.

<sup>2</sup> Operating profit divided by net sales.

<sup>3</sup> Includes foreign exchange gains and losses on long-term debt.

### 2009 VS 2008—HIGHER CHEMICALS CONTRIBUTION INCREASED NET INCOME BY \$73 MILLION

North America chlorate revenue decreased 2% from 2008, as a 13% reduction in sales volumes attributable to the global economic downturn was partially offset by stronger pricing. North America chlor-alkali revenue increased 2% from 2008 as weaker caustic prices somewhat offset higher volumes. In Brazil, lower caustic prices and a decline in sales volumes decreased chlor-alkali revenues 32%. Chlor-alkali sales volumes decreased because we reduced sales of

purchased product as this activity generates no gross margin. There was no impact on our returns in Brazil by eliminating this activity. Chlorate sales in Brazil increased 5% from the prior year as a result of higher prices.

The Canadian dollar strengthened compared to the prior year-end and chemicals contribution includes unrealized foreign exchange gains of \$50 million on the Canexus US-dollar-denominated debt. This compared to our 2008 results, which included unrealized foreign exchange losses of \$54 million.

## 2008 VS 2007—LOWER CHEMICALS CONTRIBUTION DECREASED NET INCOME BY \$76 MILLION

North America sodium chlorate revenues increased 14% in 2008 as a result of higher realized selling prices and higher sales volumes. Price increases implemented in North America in the first and third quarters more than offset the impact of the stronger Canadian dollar on US-dollar-denominated sales. Strong demand from US customers contributed to the increase in sales volumes. North American chlor-alkali revenues were up 11% in 2008 as we realized higher selling prices for caustic soda. These increases were offset by higher operating and transportation costs, as the price of fuel and power increased during 2008. In Brazil, we have a pass-through contract with our primary customer, Aracruz Cellulose, that allows us to amend our sales prices when operating costs change. Higher costs in 2008 increased the sales revenues we receive from them.

Chemicals contribution to income included foreign exchange losses of \$54 million in 2008, primarily from unrealized losses on the revaluation of US-dollar-denominated long-term debt.

## CORPORATE EXPENSES

### General and Administrative (G&A)

(Cdn\$ millions)	2009	2008	2007
General and Administrative Expense before Stock-Based Compensation	428	417	336
Stock-Based Compensation <sup>1</sup>	69	(160)	38
<b>Total</b>	<b>497</b>	<b>257</b>	<b>374</b>

<sup>1</sup> Includes cash and non-cash expenses related to our tandem option plan and stock appreciation rights plan.

### 2009 VS 2008—HIGHER COSTS DECREASED NET INCOME BY \$240 MILLION

Higher stock-based compensation expense was the primary reason for the 93% increase in G&A costs in 2009. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation obligations and related expense. Our stock price fluctuated during the year before closing at \$25.22/share, up 18% from \$21.45/share at the end of 2008. Cash payments made in connection with our stock-based compensation programs in 2009 decreased 29% from 2008 to \$79 million. Cash payments were higher in 2008 as our stock price reached a high of \$43.45/share during the year.

### 2008 VS 2007—LOWER COSTS INCREASED NET INCOME BY \$117 MILLION

During 2008, we recovered non-cash stock-based compensation costs of \$272 million as our stock price closed the year at \$21.45/share, compared to \$32.10/share the previous year. This recovery was partially offset by cash payments for stock-based compensation programs of \$112 million, 24% lower than 2007.

G&A expense before stock-based compensation increased \$81 million, primarily as a result of higher employee costs and cost inflation. An integral part of our strategy to expand our oil and gas operations has been to actively recruit highly experienced employees, positioning us for success in our core areas. We have been actively recruiting skilled individuals to strengthen our teams in Norway and the US.

## Interest

(Cdn\$ millions)	2009	2008	2007
Interest	389	334	341
Less: Capitalized	(77)	(240)	(173)
<b>Net Interest Expense</b>	<b>312</b>	<b>94</b>	<b>168</b>
Effective Interest Rate	5.0%	5.9%	6.2%

### 2009 VS 2008—HIGHER NET INTEREST EXPENSE REDUCED NET INCOME BY \$218 MILLION

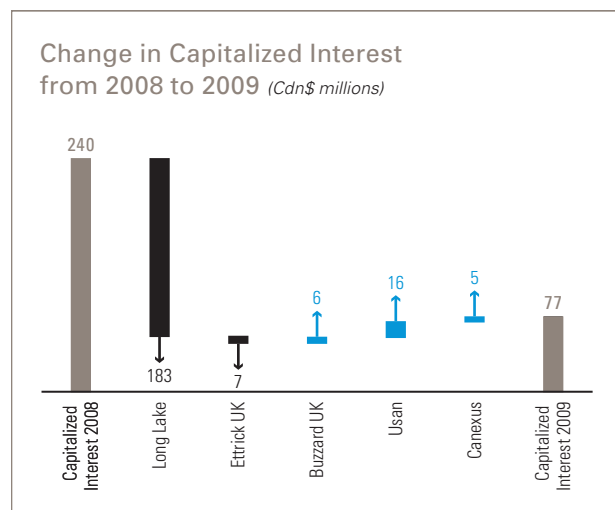
Financing costs increased \$55 million from 2008. This 16% increase was a result of higher levels of debt, partially offset by lower interest rates. Our capital investment program, including the acquisition of an additional 15% interest in Long Lake, exceeded our cash flow, causing us to draw down a portion of our term credit facility. In addition, we issued US\$1 billion of long-term notes in the third quarter, increasing interest costs by \$32 million this year. The stronger US dollar increased our US-dollar-denominated interest costs for the year by \$32 million.

During the year, capitalized interest decreased \$163 million from 2008 as a result of completing major development projects. Long Lake capitalized interest in 2009 was \$23 million, down \$183 million from 2008, while Ettrick capitalized interest decreased \$7 million during the year. This was partially offset by an increase in Usan capitalized interest of \$16 million. In addition to our Usan development, we continue to capitalize interest on the construction of the fourth platform at Buzzard and our Chemicals technical conversion project in North Vancouver.

### 2008 VS 2007—LOWER NET INTEREST EXPENSE INCREASED NET INCOME BY \$74 MILLION

Our financing costs are \$7 million lower than the previous year as our strong cash flow reduced our debt needs. Lower interest rates on our variable rate debt also reduced interest costs. In the third quarter, we completed an internal reorganization and financing of our assets in the UK. This required us to draw down approximately US\$1 billion under our term credit facilities. As a consequence, our financing costs increased in the fourth quarter of 2008.

Interest capitalized on our major development projects increased \$67 million in 2008 compared to 2007. Our Long Lake capital costs include \$207 million of capitalized interest, \$49 million higher than last year. We also capitalized interest of \$25 million on our Ettrick development. We continue to capitalize interest on our development project at Usan and the construction of the fourth platform at Buzzard.



## Income Taxes

<i>(Cdn\$ millions)</i>	2009	2008	2007
Current	776	859	434
Future	(516)	598	358
<b>Total Provision for Income Taxes</b>	<b>260</b>	<b>1,457</b>	<b>792</b>

### 2009 VS 2008—LOWER TAXES INCREASED NET INCOME BY \$1,197 MILLION

Our provision for income taxes decreased by \$1,197 million as compared to the prior year. Lower commodity prices and production, a reduction in Canadian tax rates and a fair value unrealized loss on our crude oil put options contributed to lower tax expense in 2009. During the year, future tax expense was reduced by the continued amortization of the deferred tax credit arising from the internal reorganization and financing of our North Sea assets completed in 2008. Our income tax provision includes current taxes in the UK, Yemen, Norway, Colombia and the US.

### 2008 VS 2007—HIGHER TAXES DECREASED NET INCOME BY \$665 MILLION

Our provision for income taxes increased \$665 million or 84% from the prior year. This increase was primarily due to record commodity prices and strong production at Buzzard in the UK, which has a corporate tax rate on oil and gas activities of 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia, Norway and the US.

## Other

<i>(Cdn\$ millions)</i>	2009	2008	2007
Increase (Decrease) in Fair Value of Crude Oil Put Options	(251)	203	(43)

In the fourth quarter of 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options establish a WTI floor price of US\$50/bbl on these volumes and provide a base level of price protection without limiting our upside to higher prices. Options on 60,000 bbls/d settle monthly, while the remaining options settle annually. These options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for \$39 million and are carried at fair value. At December 31, 2009, higher crude oil prices reduced the fair value of the options to \$17 million, and we recorded a fair value loss in 2009 of \$22 million.

In early 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for \$14 million and established a Dated Brent floor price of US\$60/bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of \$233 million due to lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of \$229 million in 2009.

In 2007, we purchased put options on approximately 100,000 bbls/d of our 2008 crude oil production for \$24 million. These options established an annual average Dated Brent floor price of US\$50/bbl on these volumes. These put options expired out-of-the-money.

## OUTLOOK FOR 2010

### Capital Investment

In 2010, we plan to invest \$2.5 billion in capital activities on our oil and gas operations to solidify growth beyond 2010 as follows:

- 35% on our existing producing assets, including installation of the fourth platform at Buzzard;
- 30% in development projects at Usan, offshore West Africa and progressing the sanctioning of the Golden Eagle area;
- 23% on exploration and appraisal opportunities in our key regions of the North Sea, Gulf of Mexico and offshore West Africa; and
- 12% on early stage development projects expected to contribute future production and cash flow including advancement of our Horn River shale gas play and future phases of oil sands in the Athabasca region.

The amount of this capital investment could be reduced depending on the prevailing economic environment. Details of our 2010 capital program are included in the Capital Investment section of the MD&A.

### Production

In 2010, we expect our annual production to grow approximately 4 to 6%, assuming the midpoint of our guidance, and range from 230,000 to 280,000 boe/d (200,000 to 250,000 boe/d after royalties). This growth reflects a full year of production from Ettrick and Longhorn and increasing volumes from Long Lake. At the high end of our guidance, our production growth would be as high as 15%. The low end includes the possibility of advancing the start-up of the fourth platform at Buzzard, which is currently scheduled for 2011. Advancement to 2010 would only be required if we see higher than expected levels of hydrogen sulphide. The downtime associated with advancing the start-up could reduce annual volumes by 10,000 to 15,000 boe/d.

	2010 Estimated Production		2009 Production	
	Before Royalties	After Royalties	Before Royalties	After Royalties
<i>(mboe/d)</i>				
United Kingdom	100–130	100–130	102	102
Canada	28–34	19–25	38	32
Long Lake Bitumen	20–30	18–28	8	8
Syncrude	19–24	18–23	20	19
United States	20–28	17–25	21	19
Yemen	32–37	19–23	50	30
Other Countries	1–2	1–2	4	3
<b>Total</b>	<b>230–280</b>	<b>200–250</b>	<b>243</b>	<b>213</b>

### Cash Flow and Sensitivities

We expect cash flow from operating activities to fund our capital investments in 2010, assuming the following:

WTI (US\$/bbl)	\$70
NYMEX Natural Gas (US\$/mmbtu)	\$5.50
US to Canadian Dollar Exchange Rate	\$0.90

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

<i>(Cdn\$ millions)</i>	
WTI—US\$/bbl change above US\$50	47
WTI—US\$/bbl change below US\$50 <sup>1</sup>	30
NYMEX Natural Gas—US\$0.50/mcf change	28
Exchange Rate—\$0.01 US/Cdn change	35

<sup>1</sup> Put options mitigate the impact of a price decline below US\$50 WTI (based on 90,000 puts).

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Structure

<i>(Cdn\$ millions)</i>	December 31 2009	December 31 2008
<b>Net Debt<sup>1</sup></b>		
Bank Debt	1,803	1,448
Public Senior Notes	4,982	4,582
Total Senior Debt	6,785	6,030
Subordinated Debt	466	548
Total Debt	7,251	6,578
Less: Cash and Cash Equivalents	(1,700)	(2,003)
<b>Total Net Debt</b>	<b>5,551</b>	<b>4,575</b>
<b>Equity<sup>2</sup></b>	<b>7,646</b>	<b>7,191</b>

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

2 Equity is the historical issue price of equity and accumulated retained earnings.

### Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of approximately \$5.6 billion, \$976 million higher than 2008. The year-over-year change in our net debt results from:

<i>(Cdn\$ millions)</i>	2009	2008
Capital Investment	2,742	3,066
Acquisition of Additional Working Interest at Long Lake	755	-
Cash Flow from Operating Activities	(1,886)	(4,354)
Deficiency (Excess)	1,611	(1,288)
Dividends on Common Shares	104	92
Issue of Common Shares	(57)	(64)
Repurchase of Common Shares for Cancellation	-	338
Foreign Exchange Translation of US-dollar Debt and Cash	(897)	1,012
Net Proceeds on Disposition of Assets	(17)	(6)
Other	232	87
<b>Increase in Net Debt</b>	<b>976</b>	<b>171</b>

Our net debt increased from the prior year primarily due to capital investment exceeding cash flow generated from operating activities. During the year, our capital investment included the acquisition of an additional 15% working interest in Long Lake for \$755 million and investments focused on our three key growth areas of oil sands, conventional exploration and development, and unconventional gas. Cash flow from operating activities decreased compared to the prior year mainly as a result of lower oil and gas commodity prices. This impact was partially offset as the Canadian dollar strengthened relative to the US dollar, which reduced our US-dollar-denominated debt. We currently have liquidity of approximately \$3.3 billion, which is comprised of cash and undrawn committed credit facilities, most of which are available until July 2012.

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 manage our investments through the lows of the commodity market to create future growth and value for our shareholders over the long term without putting our balance sheet under undue financial risk. Changes in our non-cash working capital can vary between periods 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.

The change in our net debt, combined with lower cash flow and earnings, increased our 2009 leverage as reflected in the following ratios:

<i>(times)</i>	<b>2009</b>	<b>2008</b>	<b>2007</b>
Net Debt to Cash Flow from Operating Activities <sup>1</sup>	2.5	1.1	1.6
Interest Coverage <sup>2</sup>	8.5	15.6	12.1

<sup>1</sup> For purposes of this calculation, cash flow from operating activities is before changes in non-cash working capital and other.

<sup>2</sup> Earnings before interest, taxes, DD&A, exploration and other non-cash expenses, divided by interest expense (before capitalized interest).

Our business strategy is focused on value-based growth through full-cycle exploration and development of conventional and unconventional resources, supplemented by strategic acquisitions when appropriate. Since most of our projects have long cycle-times requiring significant amounts of capital prior to cash flow generation, we have successfully leveraged our balance sheet many times in the past, including to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchase 20 million common shares, representing 14% of our issued common shares, in 2000;
- acquire the remaining interest in Aspen in 2003;
- acquire the Buzzard project and other key assets in the North Sea in 2004;

- construct the first phase of Long Lake beginning in 2004; and
- acquire an additional 15% in the Long Lake project and joint venture lands in 2009.

For the 12 months ended December 31, 2009, our net debt to cash flow from operating activities (before changes in non-cash working capital and other) ratio was 2.5 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.

## Change in Working Capital

<i>(Cdn\$ millions)</i>	<b>December 31 2009</b>	<b>December 31 2008</b>	<b>Increase (Decrease)</b>
Cash and Cash Equivalents	1,700	2,003	(303)
Restricted Cash	198	103	95
Accounts Receivable	2,788	3,163	(375)
Inventories and Supplies	680	484	196
Accounts Payable and Accrued Liabilities	(3,038)	(3,326)	288
Other	70	76	(6)
<b>Total</b>	<b>2,398</b>	<b>2,503</b>	<b>(105)</b>

Our working capital balances remained strong in 2009 as we weathered the economic downturn that began in late 2008.

Our capital expenditures exceeded our cash flow from operating activities, which caused us to draw upon our available liquidity and issue US\$1 billion of long-term debt. We currently have approximately \$1.7 billion of cash and cash equivalents on hand as well as significant undrawn committed credit facilities available.

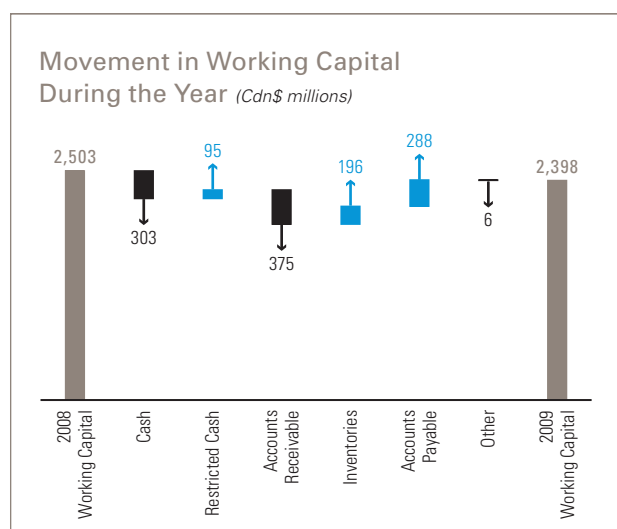
Accounts receivable and payable in our energy marketing group decreased during the year as we reduced our trading activity to focus on supporting our core physical business as

a producer/marketer. Commodity inventory increased since 2008 as our trading inventory is carried at fair value and was higher than last year as a result of stronger crude oil prices.

At December 31, 2009, our restricted cash consists of margin deposits of \$198 million (2008—\$103 million) related to exchange-traded derivative financial contracts used by our energy marketing group to economically hedge physical commodities, 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 relates to derivative financial contracts protecting our

natural gas and crude oil positions. Our physical gas purchase contracts gained in value in a declining gas price environment, while our physical crude sales contracts gained in value in a rising price environment. 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.

The weaker US dollar at the end of the year impacted our US-dollar-denominated working capital by decreasing accounts receivable, inventories and accounts payable by approximately \$215 million, \$50 million and \$210 million, respectively.



## Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity for our energy marketing business. We believe that maintaining strong liquidity is critical during periods of uncertain economic markets. We currently have liquidity of approximately \$3.3 billion, which is comprised of cash and undrawn committed credit facilities, most of which are available until 2012.

We maintain significant committed credit facilities. At December 31, 2009, we had unsecured term credit facilities of \$3.2 billion that are available until July 2012. Of these facilities, \$1.6 billion was drawn and \$407 million was utilized to support letters of credit. We also had \$492 million of uncommitted, unsecured credit facilities, of which \$86 million was supporting letters of credit outstanding at December 31, 2009. Canexus had \$451 million of committed, secured term credit facilities available until 2011, of which \$233 million was drawn at December 31, 2009.

From time to time, we access capital markets to meet our financing needs. We also use financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI and Dated Brent put options to establish a minimum value for our production. We manage our capital structure to maintain flexibility so we can fund our capital programs given the cyclical nature of the oil and gas business.

The following table shows how we financed our business activities. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

<i>(Cdn\$ millions)</i>	<b>2009</b>	<b>2008</b>	<b>2007</b>	<b>2006</b>	<b>2005</b>
Cash Flow from Operating Activities	1,886	4,354	2,830	2,374	2,143
Cash Flow from Investing Activities	(3,743)	(3,189)	(3,281)	(3,388)	(1,864)
Surplus (Deficiency)	(1,857)	1,165	(451)	(1,014)	279
Cash Flow from Financing Activities	1,821	322	677	1,081	(274)
<b>Net Cash Generated (Used)</b>	<b>(36)</b>	<b>1,487</b>	<b>226</b>	<b>67</b>	<b>5</b>

In 2005, we used cash flow and proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately \$1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US\$1.5 billion in senior debt to repay outstanding term credit facilities and \$150 million in medium-term notes, as well as to fund our 2007 capital program.

In 2008, our cash flow from operating activities exceeded capital expenditures by approximately \$1.3 billion and we used this excess to: i) build our cash balances; ii) repurchase approximately 12 million common shares at a cost of \$338 million; and iii) repay debt including maturing medium term notes of \$125 million. We also borrowed approximately US\$1 billion under our term credit facilities as a result of an internal reorganization and financing of our UK North Sea assets.

In 2009, our capital investment, including the acquisition of an additional working interest in Long Lake, exceeded our cash flow from operating activities. The purchase of Long Lake was funded primarily from accumulating excess cash in 2008. In response to improving credit markets, we also issued US\$1 billion of senior notes during the year, with US\$300 million maturing in 10 years and US\$700 million maturing in 30 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. The issuance of the new debt increased the average term-to-maturity of our debt to 17 years.

Our marketing business also requires liquidity to support its activities. We require liquidity for working capital and cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial

agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require collateral to be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. We have developed mitigation strategies to significantly reduce our overall exposure if such a downgrade were to occur. We believe our current liquidity is sufficient enough to fund this exposure, if necessary. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single-day margin call we received during 2009 was \$37 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

## Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our 2010 capital investment budget is approximately \$2.5 billion, which we expect to finance from cash flow and existing cash. We continue to monitor economic conditions and commodity prices and will adjust our capital investment program accordingly. We also continue to work with suppliers and contractors to negotiate supply rates that reflect existing market conditions.

In 2010, we expect cash flow from operating activities to fund our capital investment program assuming:

WTI (US\$/bbl)	\$70
NYMEX Natural Gas (US\$/mmbtu)	\$5.50
US to Canadian Dollar Exchange Rate	\$0.90

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2010 section on page 79 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2009, we have \$1.7 billion in cash, \$1.6 billion of undrawn committed credit facilities and \$492 million of undrawn uncommitted credit facilities. The average term of our public debt is approximately 17 years. The only debt maturity of significance in the next few years is our \$3.2 billion term credit facility, which matures in July 2012, although historically we have been able to negotiate an extension with our lenders. At December 31, 2009, we had drawn \$1.6 billion on this facility. Given the long term-to-maturity of a significant portion of our debt, we believe we are well positioned to bring our near-completion projects to production and pursue our next generation of growth while preserving our liquidity.

Our debt maturities over the next five years are:

<i>(Cdn\$ millions)</i>	2010	2011	2012	2013	2014
Term Credit Facilities <sup>1</sup>	-	-	1,570	-	-
Long-Term Notes	-	-	-	523	-
Canexus LP Term Credit Facilities	-	233	-	-	-
Canexus LP Notes	-	-	-	52	-
Canexus Convertible Debt	-	-	-	-	46
<b>Total</b>	-	<b>233</b>	<b>1,570</b>	<b>575</b>	<b>46</b>

<sup>1</sup> \$3.2 billion available until July 2012.

For the past several years, we invested significant capital in a number of major development projects, including Buzzard, Long Lake and Ettrick. The large capital investment required in these projects is behind us and we expect these assets will make significant contributions to our future cash flows. Cash flows generated from these projects allow us to repay debt and invest in our next generation of new growth projects, such as: i) Usan, offshore West Africa; ii) shale gas in the Horn River Basin; and iii) the Golden Eagle area in the UK North Sea. In 2010, we expect to invest \$575 million to progress our Usan development, \$200 million at Horn River and \$50 million at Golden Eagle. While these development projects lack exploration risk, they are subject to other risks, including higher than anticipated capital costs or delayed start-up. We maintain significant undrawn committed credit facilities to manage these risks. We also have a US\$3.5 billion shelf prospectus filed in the US and Canada for sales of debt securities and common shares, under which we issued US\$1 billion of debt securities in July.

We are well positioned with our current debt structure.

Our only debt covenant requires us to maintain a long-term debt to EBITDA ratio of less than 3.5. At December 31, 2009, this ratio was approximately 1.9 times. We do not expect to exceed 3.5 based on our current debt levels and planned operations.

With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets, and flexibility to reduce future capital expenditure programs, we expect to be able to fund all planned capital, dividend distributions and debt repayments and meet other obligations that may arise from our oil and gas, chemicals and energy marketing operations.

In 2009 and 2008, the Board declared common share dividends of \$0.20 and \$0.175, respectively. In each of the three years preceding 2008, the Board declared common share dividends of \$0.10 per share each year.

## Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities.

We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

(Cdn\$ millions)	Payments				
	Total	< 1 year	1–3 years	4–5 years	> 5 years
Long-Term Debt	7,343	–	1,803	621	4,919
Interest on Long-Term Debt <sup>1</sup>	8,052	361	721	688	6,282
Operating Leases <sup>2</sup>	647	117	185	179	166
Capital Leases	120	6	12	11	91
Energy Commodity Contract Liabilities	694	482	180	32	–
Transportation and Storage Commitments <sup>2</sup>	977	303	345	209	120
Work Commitments and Purchase Obligations <sup>3</sup>	2,749	1,299	1,079	313	58
Asset Retirement Obligations	2,341	35	79	162	2,065
<b>Total</b>	<b>22,923</b>	<b>2,603</b>	<b>4,404</b>	<b>2,215</b>	<b>13,701</b>

<sup>1</sup> Excludes interest on term credit facilities of \$1.6 billion and Canexus term credit facilities of \$233 million as the amounts drawn on the facilities fluctuate. Based on amounts drawn at December 31, 2009 and existing variable interest rates, we would be required to pay \$19 million per year until the outstanding amounts on the term credit facilities are repaid.

<sup>2</sup> Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.

<sup>3</sup> Some of these payments relate to work commitments that we can cancel without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Short-term and long-term debt amounts are included on our December 31, 2009 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allow our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas and financial derivatives used to manage our exposure to commodity prices. For certain contracts, we may net settle. These contracts are included in our Consolidated Balance Sheet on a net basis at fair value.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and include commitments for the Usan development project in Nigeria over the next five years

(\$585 million). Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates. The majority of our 2010 capital investment is discretionary.

- We have included \$998 million in work commitments for drilling rigs we have contracted in the UK, Norway and the Gulf of Mexico over the next five years.
- We have \$2,341 million of undiscounted asset retirement obligations after inflation. As of December 31, 2009, the discounted value (\$1,053 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including \$35 million of estimated current obligations). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have a net pension liability of \$55 million for our defined benefit pension plan. This includes a pension asset of \$21 million from over contributing to the defined benefit plan, offset by a liability of \$76 million for supplemental pension benefits. Supplemental pension benefits are funded from our operating cash flows and backed with an irrevocable letter of credit. Canexus has unfunded pension obligations of \$12 million and our share of the unfunded pension obligation for Syncrude is \$56 million.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are not determinable.

- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2010.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when, future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against certain possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

## Credit Ratings

Currently, our senior debt is rated BBB by Dominion Bond Rating Service (DBRS), Baa3 by Moody's Investor Service, Inc. (Moody's) and BBB- by Standard & Poor's (S&P). DBRS, Moody's and S&P all currently rate our outlook as stable. We believe our financial results, ample liquidity and financial flexibility continue to support our credit ratings.

## Financial Assurance Provisions in Commercial Contracts

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at December 31, 2009, if we were downgraded to non-investment grade we could be required to post collateral of up to \$962 million, which we expect we

would be able to manage down. These obligations are reflected on our balance sheet and are expected to decrease over the next couple of years with the rationalization of our marketing business. The posting of collateral merely accelerates the payment of such amounts and lowers our available liquidity. Just as we may be required to post collateral if we were downgraded below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us if they are downgraded to non-investment grade.

## Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees in Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2009, we had outstanding letters of credit supported by \$407 million (US\$389 million) of unsecured term credit facilities and \$86 million (US\$82 million) of uncommitted unsecured credit facilities.

## Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference for a discussion of our contingencies.

## CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: i) the reported amounts of our assets and liabilities; ii) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and iii) our revenues and expenses during the reporting period. Our management review these estimates, 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 the estimation of reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

### Oil and Gas Accounting— Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated remaining reserves. The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions. Refer to the Basis of Reserves Estimates on page 29 for a description of our process for estimating reserves.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and, if not, we expense the costs immediately. In 2009, \$115 million of our total \$445 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by \$204 million, net of income tax;
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired, and proved developed reserves are used where a property is drilled and developed. In 2009, oil and gas depletion of \$1,425 million (before impairments) was recorded in depletion, depreciation, amortization and impairment expense. If our proved reserves estimates changed by 10%, our depletion, depreciation, amortization and

impairment expense would have changed by approximately \$143 million, assuming no other changes to our reserves profiles; and

- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

### Impairments

#### PROPERTY, PLANT AND EQUIPMENT

We evaluate our long-lived assets for impairment if an adverse event or change occurs. Among other things, these might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs or significant or adverse political or regulatory changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected assets to determine if they are impaired. If the undiscounted future cash flow for an asset is less than the carrying amount of that asset, we estimate its fair value using a discounted cash flow model.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements: future prices and costs, reserves and discount rates. Our estimates of future prices are based on our assumptions of long-term prices and operating and development costs and require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years,

prices for WTI and NYMEX gas have ranged from US\$32/bbl to US\$147/bbl and US\$2.41/mmbtu to US\$15.38/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing future strip prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in these estimates would impact all our businesses with the exception of chemicals and energy marketing.

It is difficult to determine and assess how a decrease in proved reserves impacts our impairment tests. The relationship between our reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

## GOODWILL

We test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount and at least annually. Our goodwill impairment test compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds the fair value, the goodwill is considered impaired. To measure the amount of impairment, we allocate the estimated fair value to the underlying assets and liabilities, resulting in an implied fair value of goodwill. If the carrying amount of the goodwill exceeds the implied fair value, an impairment loss equal to the excess is included in net income.

The process of assessing goodwill for impairment requires us to estimate the fair values of our assets using one or more valuation techniques, including present-value calculations of estimated future cash flows. This process involves making various assumptions and judgments about future commodity prices, future activity levels, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

## Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years into the future. Additionally, contracts and regulations are often vague and unclear as to what constitutes removal and remediation. Furthermore, the ultimate financial impact is not always clearly known and cannot be reasonably estimated as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental, political and safety environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accretes with the passage of time.

A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our DD&A expense.

## Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and income tax purposes. We carry on business in several countries and, as a result, we are subject to income taxes in numerous jurisdictions. The determination of current income tax is inherently complex, interpretations will vary, and we are required to make certain judgments. Our income tax filings are subject to audits and reassessments and we believe we have adequately provided for all income tax obligations. However, changes

in facts, circumstances and interpretations as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

## Derivatives and Fair Value Measurements

We enter into contracts to purchase and sell crude oil and natural gas and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively, derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes.

The fair value of derivative contracts is estimated. Wherever possible, this estimate is based on quoted market prices and, if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be: i) readily observable; ii) market corroborated; or iii) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. Additionally, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net open sell position and the bid price when we have a net open buy position. We incorporate the credit risk associated with counterparty default into our estimates of fair value.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results. We performed a sensitivity analysis of inputs used to calculate the fair value of the instruments that are based on unobservable inputs. Using reasonably possible alternative assumptions, the fair value of these instruments would change by \$12 million (before tax).

## NEW ACCOUNTING PRONOUNCEMENTS

### International Financial Reporting Standards Adoption Plan

We are required to adopt International Financial Reporting Standards (IFRS) for our interim and annual financial reporting purposes beginning January 1, 2011. A project team, consisting of dedicated and experienced personnel who have IFRS knowledge, has been set up to manage this transition and to ensure successful implementation within the required time frame.

A steering committee comprised of senior management has been established for project oversight. The steering committee has the responsibility to ensure the project is adequately planned in sufficient detail, appropriate resources are made available, necessary milestones are established and project progress is properly monitored. These senior leaders are also responsible for internal controls over financial reporting and our disclosure controls and procedures. The audit and conduct review committee of the Board of Directors regularly receives progress reporting on the status of the IFRS transition project and training of IFRS principles.

Our project consists of five phases: diagnostic, design and plan, develop solution, implementation and closeout. We are currently in the Implementation phase, where we are making the necessary changes to business processes, financial reporting and supporting information technology systems to allow us to capture and report on IFRS financial information throughout 2010 and onward.

Project activities and key milestones are documented in the following chart:

Key Activity	Key Milestone	Status
<b>Financial Information</b>		
<ul style="list-style-type: none"> <li>Identify differences between Canadian GAAP and IFRS</li> <li>Revise accounting policies under IFRS</li> <li>Identify potential adjustments to initial IFRS financial statements</li> <li>Develop IFRS-compliant financial statements, including transition period disclosures</li> </ul>	<ul style="list-style-type: none"> <li>Comprehensive analysis of IFRS differences identified in the diagnostics phase</li> <li>Senior management approval of IFRS accounting policies</li> <li>Develop draft IFRS financial statements and disclosures</li> </ul>	<ul style="list-style-type: none"> <li>Comprehensive analysis completed mid 2009</li> <li>Received senior management approval of IFRS accounting policies</li> <li>Areas of potential adjustment to opening balance sheet have been identified</li> <li>Draft IFRS financial statements and note disclosures are substantially complete</li> </ul>
<b>Training and Communication</b>		
<ul style="list-style-type: none"> <li>Develop and deliver targeted IFRS training to employees and management</li> <li>Ensure internal and external stakeholders receive ongoing appropriate communications</li> <li>Develop and deliver targeted IFRS training to senior management and Board of Directors</li> </ul>	<ul style="list-style-type: none"> <li>Delivery of training in 2009 targeted to affected employees</li> <li>Ongoing communication with major internal and external stakeholders</li> </ul>	<ul style="list-style-type: none"> <li>Targeted training completed in 2009</li> <li>Strategy for follow-up training in 2010 developed</li> <li>Regular communication with Project Steering Committee, senior management and Audit Committee throughout the year</li> <li>Quarterly disclosure of project status in MD&amp;A</li> </ul>
<b>Information Technology</b>		
<ul style="list-style-type: none"> <li>Ensure systems are able to adequately support conversion to IFRS and ongoing financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Be IFRS data capture ready January 1, 2010</li> <li>Ensure dual GAAP reporting capability throughout 2010</li> </ul>	<ul style="list-style-type: none"> <li>System testing for IFRS data capture complete</li> <li>Dual GAAP reporting capability testing complete</li> </ul>
<b>Business Process</b>		
<ul style="list-style-type: none"> <li>Ensure business processes and control environment properly support conversion to IFRS and ongoing financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Implement necessary business process and key control changes to ensure adequate internal control over financial reporting</li> </ul>	<ul style="list-style-type: none"> <li>Necessary changes to business process have been designed</li> <li>Key controls designed to ensure adequate internal control over financial reporting on IFRS results throughout 2010</li> </ul>

## Summary of Accounting Differences between Canadian GAAP and IFRS

We determined that the majority of our existing Canadian GAAP oil and gas accounting policies are acceptable under IFRS. However, detailed analysis has identified differences, the most significant of which will impact certain aspects of our accounting for property, plant and equipment, asset retirement obligations, impairments of assets and share-based payments.

## PROPERTY, PLANT AND EQUIPMENT

Significant components of property, plant and equipment with different useful lives must be accounted for and depreciated separately. Instances of major maintenance, turnarounds or inspections must also be capitalized and depreciated until the next scheduled major maintenance activity. Our current policy is to expense these items unless they result in improvements that increase capacity or extend the useful life. We anticipate that retrospective application of these concepts will have an effect on the accumulated depreciation balance on transition for certain of our assets with large production and processing facilities.

## ASSET RETIREMENT OBLIGATIONS

There are differences in the calculation methodology for determining asset retirement obligations, which are expected to affect the obligations recorded in all of our operating areas. These obligations will be recalculated and asset retirement obligations and property, plant and equipment balances will be adjusted on the transition date.

## IMPAIRMENT OF ASSETS

IFRS does not require a cost recoverability test when testing long-lived assets for impairment. Consequently, it is possible that we may have more impairments where carrying values of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis but could not be supported on a discounted cash flow basis under IFRS. However, the extent of future impairments under IFRS may be partially offset by potential reversals of previous impairment losses where circumstances that gave rise to the impairment reverses.

## SHARE-BASED PAYMENTS

We currently use the intrinsic method to account for our cash-settled stock-based compensation. We expect that the IFRS requirement to value stock-based compensation at fair value each reporting period may result in less volatility in our reported earnings each period. We expect to use a fair value model such as Black-Scholes to value our stock-based compensation each period.

## ONE-TIME ADJUSTMENTS ON TRANSITION TO IFRS

IFRS allows certain adjustments to financial information on transition where retrospective restatement would either be onerous or would not provide more useful information. We expect to make one-time transitional adjustments on January 1, 2010 to our defined benefit pension obligations to reflect previously unrecognized actuarial losses and to other comprehensive income to reclassify accumulated foreign exchange gains and losses directly to retained earnings.

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

We continue to monitor the development of new standards, and any changes will be incorporated as required.

In recent years, the CICA has issued standards with the intent to converge with IFRS to facilitate the transition in 2011. As a result, the majority of our current Canadian GAAP accounting policies are acceptable under IFRS.

As a foreign private issuer in the US, we are permitted to file financial statements prepared under IFRS without reconciliation to US GAAP with the SEC. Effective January 1, 2011, we will adopt IFRS as our basis for accounting. The impact of this change is that we will no longer prepare a reconciliation of our results to US GAAP. It is possible that certain of our accounting policies under IFRS could be different from US GAAP, but we expect that most accounting policies will remain consistent or converge with US GAAP as the International Accounting Standards Board (IASB) and the Financial Accounting Standards Board (FASB) undertake joint projects.

## US Pronouncements

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 standard is effective at the beginning of the first annual reporting period after November 15, 2009. We do not expect the adoption of this standard to have a material impact on our results of operations or financial position.

On January 6, 2010, FASB issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which is effective for the year ended December 31, 2009. The guidance expands the definition of oil and gas producing activities to include unconventional sources such as oil sands, changes the price used in reserve estimation from the year-end December 31 price to the simple average of the first-day-of-the-month price for the previous 12 months and requires disclosures for geographic areas that represent 15% or more of proved reserves. The information required by this standard has been included in the unaudited supplementary data in Item 8.

We follow the successful efforts method of accounting for our oil and gas activities, which depends on the estimated reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess our oil and gas assets for impairment, when necessary. Adoption of these amendments at December 31, 2009 did not have an impact on our results of operations or financial position.

## ITEM 7A.

### Quantitative and Qualitative Disclosures about Market Risk

We are exposed to normal market risks inherent in the oil and gas, energy marketing and chemicals businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

## NON-TRADING

### Commodity Price Risk

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

Our crude oil prices are based on various reference prices, primarily WTI and Brent and other prices that generally track the movement of WTI and Brent. Adjustments are made to the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

We are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and supply and demand fundamentals and, to a lesser extent, local market conditions.

In 2009, WTI averaged US\$61.80/bbl, reaching a high of US\$82/bbl and a low of US\$32/bbl. Dated Brent, on which approximately 60% of our production is priced, averaged US\$61.51/bbl, reaching a high of US\$78/bbl and a low of US\$39/bbl. NYMEX natural gas prices averaged US\$4.16/mmbtu in 2009, reaching a high of US\$6.24/mmbtu and a low of US\$2.41/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2010 cash flow from operating activities and net income are as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>
WTI—US\$1/bbl change above US\$50	47	45
WTI—US\$1/bbl change below US\$50 <sup>1</sup>	30	27
NYMEX Natural Gas—US\$0.50/mcf change	28	19

<sup>1</sup> Put options mitigate the impact of a price decline below US\$50 WTI (based on 90,000 puts).

These sensitivities are based on our estimated 2010 oil and gas production and assume a US/Canadian dollar exchange rate of \$0.90. Our estimated oil and gas production range for 2010 is between 230,000 and 280,000 boe/d before royalties, of which approximately 15% is gas.

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

In 2009, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2010. These put options have established an annual average WTI floor price of US\$50/bbl on about 90,000 bbls/d of production.

## Foreign Currency Risk

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 and chemicals operations; and
- short-term and long-term borrowings.

The US/Canadian dollar exchange rate averaged \$0.88 in 2009, ranging from a low of \$0.77 to a high of \$0.97.

Our sensitivities to the US dollar and the expected impact of a one-cent change on our 2010 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>	<b>Capital Expenditures</b>	<b>Long-Term Debt</b>
\$0.01 Change in US to Cdn	35	20	20	60

Our sensitivities to changes in the US/Canadian dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar-denominated long-term debt for 2010. These estimates are based on a WTI price of US\$70/bbl, a NYMEX natural gas price of US\$5.50/mmbtu and a US/Canadian dollar exchange rate of \$0.90.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as part of their sales are denominated in US dollars. Canexus periodically purchases US-dollar call options to reduce this exposure and at December 31, 2009 had the following outstanding option contracts:

- the right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.9479 from January 1, 2010 to March 31, 2010; and
- the right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.9302 from January 1, 2010 to June 30, 2010.

We do not have any material exposure to highly inflationary foreign currencies.

## Interest Rate Risk

We are exposed to fluctuations in interest rates on our floating-rate debt.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2010 cash flow from operating activities and net income is as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>
<b>Interest Rates—1% change in rates</b>	<b>16</b>	<b>12</b>

Our sensitivity to changes in interest rates is based on 2010 estimated average floating-rate debt of \$1.6 billion and a US/Canadian dollar exchange rate of \$0.90.

Our floating-rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating-rate borrowings and facilities. At December 31, 2009, fixed-rate borrowings comprised 75% (2008—78%) of our long-term debt at an effective average rate of 6.4% (2008—6.4%). During the year, we periodically borrow under our committed, unsecured, term credit facilities, and at December 31, 2009, floating-rate debt comprised 25% (2008—22%) of our long-term debt at an effective average rate of 1.02% (2008—2.7%), ranging from a low of 0.91% to a high of 1.22% during 2009.

## TRADING

### Commodity Price Risk

Our marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the globe, including crude oil, natural gas, electricity and other commodities. We do 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 come from this physical business, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

We also seek to profit from our views on the future direction of energy commodity pricing relationships, primarily between different locations, time periods or 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 day-to-day basis.

The physical and financial marketing and trading activities we undertake expose us to the risk of loss (and provide the opportunity to profit) from a range of factors, including:

- changes in the prices of commodities at specific locations;
- changes in the relative level of nearer-term prices to future prices;
- changes in the relative value of different qualities of a commodity;
- changes in the volatility of commodity prices;
- changes in the relationships between energy commodity prices and/or derivative instruments;
- changes in the operational costs of our physical transportation and storage contracts;
- physical or financial loss of physical product; and
- disputes over terms of deals and contracts.

In order to manage these risks we have risk management systems and processes, including:

- reporting to the Board of Directors;
- reporting to the Executive Risk Management Committee;
- oversight of activities by experienced commercial management;
- a separate Risk Management Office; and
- comprehensive policies, procedures and controls.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor and report our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

<i>(Cdn\$ millions)</i>	2009	2008	2007
<b>Value-at-Risk</b>			
Year-End	11	25	26
High	24	40	38
Low	9	19	24
Average	15	30	30

If a market shock occurred as 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.

Throughout the second half of 2008 and into 2009, we realigned our marketing strategies and positions to focus on physical businesses that had been built around storage, blending and transportation. To this end, we reduced our trading levels in an orderly fashion recognizing the challenging economic environment. We exited trading positions that do not support our physical business.

## CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Approximately 72% 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. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a formal credit process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Executive Risk Management Committee and the Finance Committee of the Board;
- set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. During 2008 and 2009, we have taken the following specific actions for certain counterparties deemed to be at higher risk of non-performance:

- ceased trading activities;
- significantly reduced and, in some cases, revoked credit privileges;
- redirected business to: i) exchanges or clearing houses; and ii) entities with physical-based operations;
- increased “set off” arrangements with counterparties; and
- increased collateral and margining requirements where possible.

At December 31, 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 rating. One other counterparty made up more than 5% of our credit exposure. In addition, the following table illustrates the composition of credit exposure by credit rating:

Credit Rating	2009	2008
A or Higher	67%	65%
BBB	26%	29%
Non-investment Grade	7%	6%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of 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 have 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 our own credit risk, into our estimates of fair value.

## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—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 chemical prices;
- future production levels;
- 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 operating 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 or 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 that 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 or 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; and
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the section titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A. 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 our 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.

## SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a voluntary Form 10-K (and related forms) filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In Canada, *NI 51-101—Standards of Disclosure for Oil and Gas Activities* prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. Nexen reserves disclosures are made in reliance upon exemptions granted to Nexen by Canadian securities regulators from certain requirements of NI 51-101, which permits us to:

- prepare our reserves estimates and related disclosures in accordance with SEC disclosure requirements, generally accepted industry practices in the US and the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) standards modified to reflect SEC requirements;
- substitute those SEC disclosures for much of the annual disclosure required by NI 51-101; and
- rely upon internally-generated reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, without the requirement to have those estimates evaluated or audited by independent qualified reserves consultants.

As a result of these exemptions, Nexen's disclosures may differ from other Canadian companies, and Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US, whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC's technical rules in estimating reserves differ from NI 51-101 in areas such as the use of reliable technology, aerial extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using the year's 12-month average prices and costs held constant, whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of reserves by geographic area whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC prescribes certain information about proved and probable undeveloped reserves and future development costs, whereas NI 51-101 requirements are different;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions, whereas NI 51-101 requires that various F&D costs per boe and additional information be disclosed;
- the SEC leaves the engagement of independent qualified reserves consultants to the discretion of a company's board of directors, whereas NI 51-101 requires issuers to engage such evaluators;

- the SEC does not allow proved and probable reserves to be aggregated, whereas NI 51-101 requires issuers to disclose such; and
- the reserves disclosures in this document have not been reviewed by the independent qualified reserves consultants, whereas NI 51-101 requires them to review it.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; and
- because reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.