# Cenovus Energy Inc.

Management's Discussion and Analysis
For the Period Ended June 30, 2011

*This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated July 25, 2011, should be read with our unaudited interim consolidated financial statements for the period ended June 30, 2011 ("interim Consolidated Financial Statements"), as well as the audited consolidated financial statements for the year ended December 31, 2010 (the "Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory section at the end of this MD&A.*

*Management is responsible for preparing the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board"). The annual MD&A is approved by the Board.*

*This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented on an IFRS basis. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.*

**WHERE TO FIND**:

## INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, and had a market capitalization of approximately $27 billion on June 30, 2011. For the first half of 2011, our total crude oil and NGLs production was in excess of 129,500 barrels per day and our natural gas production was in excess of 650 MMcf/d. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca region is our Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to reduce the volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Saskatchewan, and to continue the assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. One of our most significant objectives is to embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

The Company's strategy is to focus on the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and therefore we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects in this area are as follows:

| | Ownership Interest |
|---|---|
| Narrows Lake | 50 percent [1] |
| Grand Rapids | 100 percent |
| Telephone Lake | 100 percent |

[1] Approximate ownership interest

For our Narrows Lake property, located within the Christina Lake Region, we have submitted a joint application and environmental impact assessment. This project is expected to have a gross production capacity of 130,000 barrels per day. At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. If this pilot is successful, we expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 barrels per day in the fourth quarter of 2011. Our 100 percent owned Telephone Lake property is located within the Borealis Region. In the fourth quarter of 2011, we expect to submit a revised regulatory application, which increases the planned gross production capacity from 35,000 to 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016 we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing properties and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations and prudent use of balance sheet capacity.

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned late 2011 coker startup of the Coker and Refinery Expansion ("CORE") project at the Wood River refinery. We also employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful dividends as part of delivering a strong total shareholder return over the long-term.

## OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.

- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide sequestration project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations**, which primarily includes unrealized gains or losses recorded on derivative financial instruments, gains or losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

## OVERVIEW OF THE SECOND QUARTER OF 2011

### OPERATIONAL RESULTS

While it was a challenging quarter, operational results were as expected. There was an overall decrease in production in the second quarter of 2011, most of which was due to scheduled turnarounds at Foster Creek and Christina Lake which were completed with less impact than expected. There were also a number of factors which were outside of our control. Significant factors that affected our second quarter operational results compared to 2010 include:

- Foster Creek average production was 50,373 barrels per day as we completed a scheduled turnaround, which reduced average production by approximately 7,400 barrels per day. Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity;
- Christina Lake production averaging 7,880 barrels per day, an increase of two percent, despite completing a scheduled turnaround which reduced average production by approximately 800 barrels per day;
- Pelican Lake production was curtailed for approximately two weeks, including a period of complete shut down of approximately seven days due to pipeline transportation disruptions caused by wild fires in the Slave Lake area of northern Alberta. This reduced average production by approximately 2,100 barrels per day. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened;
- Average production declined 2,200 barrels per day at our Weyburn operations primarily due to power outages and flooding which resulted in the shut-in of up to 150 production wells over the second half of June and interrupted the supply of carbon dioxide;
- Flooding in southern Saskatchewan also restricted access to our Bakken and Lower Shaunavon operations resulting in a shut-in of production wells, and slowed development activities, reducing our average production by approximately 3,100 barrels per day; and
- A 13 percent (97 MMcf/d) decrease in our natural gas production volumes consistent with our strategy of divesting of non-core properties (five percent), reduced capital investment in response to weak natural gas prices and natural declines.

### PROJECT UPDATES

A major milestone was reached at Christina Lake as we began injecting steam at phase C which is ahead of schedule. First production from phase C is expected to occur in the third quarter of 2011.

In April 2011, we received regulatory approval from the Alberta Energy Resources Conservation Board ("ERCB") for expansion phases E, F and G at Christina Lake. When all three phases are complete, Christina Lake's gross production capacity is expected to increase to 218,000 barrels per day. Engineering and equipment fabrication for Christina Lake phase E is already underway with first production planned for 2014. Phase F is expected to begin production in 2016 and phase G in 2017.

In the second quarter of 2011 we also received:

- Partner approval for Foster Creek phases F, G and H and Christina Lake phase E; and
- Approval from the Alberta Department of Energy ("ADOE") to include Foster Creek expansion phases F, G and H capital investment to date as part of our existing Foster Creek royalty calculation which resulted in a reduction of approximately $65 million in our royalty expense.

## CAPITAL ACTIVITIES

In April 2011, we increased our planned capital investment for 2011 by approximately $190 million to take advantage of opportunities to advance crude oil development. Capital expenditures for our Oil Sands and Conventional segments increased by $77 million for the quarter and $371 million for the six months ended June 30, 2011 compared to the same periods in 2010. The increased Oil Sands segment spending was primarily due to work continuing on phases F, G and H at Foster Creek and phases D and E at Christina Lake, while the Conventional spending was focused on crude oil opportunities including tight oil development. Second quarter expansion and development highlights include:

- Phase D expansion at Christina Lake continuing to progress with expected first production in the first quarter of 2013;
- Increased capital investment in our Conventional segment as part of our development strategy, although we remain below plan due to restricted access arising from flooding in southern Saskatchewan; and
- Additional progress on the CORE project at Wood River with coker start up expected in the fourth quarter of 2011.

## FINANCIAL RESULTS

Crude oil prices, including WTI and WCS, were higher in the second quarter and the WTI-WCS differential averaged less than US$18.00 per barrel, primarily due to lower Canadian inventory levels of WCS compared to earlier in 2011. The higher crude oil prices improved operating cash flow from our Oil Sands and Conventional operations, although the higher crude oil prices, specifically WTI, had a negative impact on our royalty expense and crude oil financial instruments. Refining crack spreads were strong in the quarter, which lead to a significant increase in operating cash flow from our Refining and Marketing operations. The financial highlights for the second quarter of 2011 compared to 2010 include:

- Revenues increasing $915 million, or 30 percent, primarily due to improved refined product prices, a 32 percent increase in the average sales prices for crude oil and NGLs and decreased royalties for Foster Creek with the ADOE approval of expansion phases F, G and H capital investment to date being included in our existing Foster Creek royalty calculation;
- Increased crude oil benchmark prices partially offset by a strengthened Canadian dollar which increased our operating netback;
- Decreased natural gas volumes and sales prices contributed to lower Conventional operating cash flow;
- Operating cash flow of $325 million from Refining and Marketing, an increase of $345 million, primarily due to higher refining crack spreads;
- Our Conventional natural gas operations generating $158 million in operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;
- Cash flow of $939 million, increasing 75 percent from the second quarter of 2010, primarily due to the significant increase in operating cash flow from Refining and Marketing;
- Operating earnings increasing $252 million to $395 million, primarily due to higher cash flow and lower depreciation, depletion and amortization expense partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures); and
- Continuing our quarterly dividend of $0.20 per share.

## OUR BUSINESS ENVIRONMENT

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding our financial results.

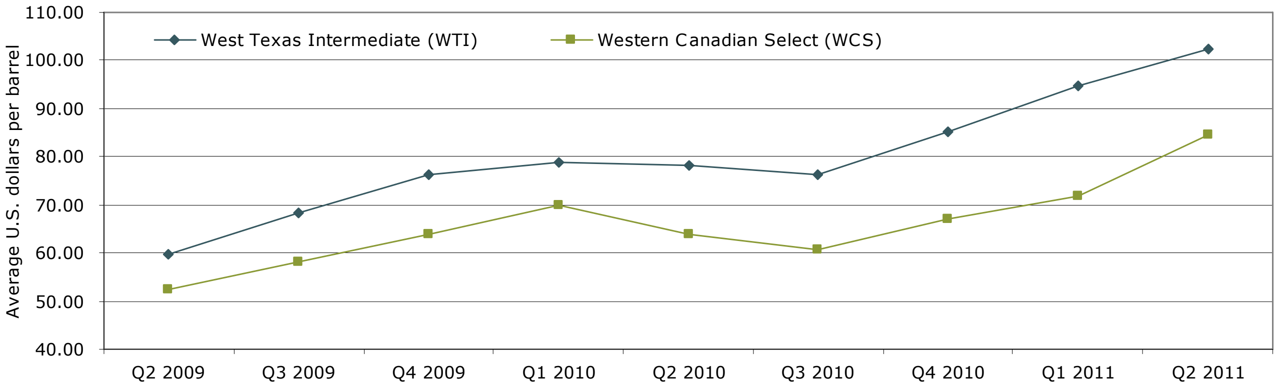
### Selected Benchmark Prices [1]

| | Six Months Ended June 30 | | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2011 | 2010 | 2010 | 2010 | 2010 | 2009 | 2009 | 2009 |
| **Crude Oil Prices** *(US$/bbl)* | | | | | | | | | | | |
| West Texas Intermediate (WTI) | | | | | | | | | | | |
| Average | **98.50** | 78.46 | **102.34** | 94.60 | 85.24 | 76.21 | 78.05 | 78.88 | 76.13 | 68.24 | 59.79 |
| End of period spot price | **95.42** | 75.63 | **95.42** | 106.72 | 91.38 | 79.97 | 75.63 | 83.45 | 79.36 | 70.46 | 69.82 |
| Western Canadian Select (WCS) | | | | | | | | | | | |
| Average | **78.25** | 66.89 | **84.70** | 71.74 | 67.12 | 60.56 | 63.96 | 69.84 | 64.01 | 58.06 | 52.37 |
| End of period spot price | **75.32** | 61.38 | **75.32** | 91.37 | 72.87 | 64.97 | 61.38 | 70.25 | 71.84 | 59.76 | 59.12 |
| Average Price – Differential WTI-WCS | **20.25** | 11.57 | **17.64** | 22.86 | 18.12 | 15.65 | 14.09 | 9.04 | 12.12 | 10.18 | 7.42 |
| Condensate (C5 @ Edmonton) | **105.65** | 83.91 | **112.33** | 98.90 | 85.24 | 74.53 | 82.87 | 84.98 | 74.42 | 65.76 | 58.07 |
| Average Price – Differential WTI-Condensate (premium)/discount | **(7.15)** | (5.45) | **(9.99)** | (4.30) | - | 1.68 | (4.82) | (6.10) | 1.71 | 2.48 | 1.72 |
| **Refining Margin 3-2-1 Crack Spread** [2] *(US$/bbl)* | | | | | | | | | | | |
| Chicago | **22.81** | 8.86 | **29.00** | 16.62 | 9.25 | 10.34 | 11.60 | 6.11 | 5.00 | 8.48 | 10.95 |
| Midwest Combined (Group 3) | **23.12** | 9.10 | **27.19** | 19.04 | 9.12 | 10.60 | 11.38 | 6.82 | 5.52 | 8.06 | 9.16 |
| **Natural Gas Prices** | | | | | | | | | | | |
| AECO *($/GJ)* | **3.56** | 4.36 | **3.54** | 3.58 | 3.39 | 3.52 | 3.66 | 5.08 | 4.01 | 2.87 | 3.47 |
| NYMEX *(US$/MMBtu)* | **4.21** | 4.69 | **4.31** | 4.11 | 3.80 | 4.38 | 4.09 | 5.30 | 4.17 | 3.39 | 3.50 |
| Basis Differential NYMEX-AECO *(US$/MMBtu)* | **0.36** | 0.25 | **0.42** | 0.29 | 0.28 | 0.78 | 0.32 | 0.19 | 0.19 | 0.67 | 0.39 |
| **Foreign Exchange** | | | | | | | | | | | |
| Average U.S./Canadian dollar exchange rate | **1.024** | 0.967 | **1.033** | 1.015 | 0.987 | 0.962 | 0.973 | 0.961 | 0.947 | 0.911 | 0.857 |

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. For our average sales prices and realized risk management results, refer to the Operating Netbacks in the Results of Operations section of this MD&A.
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

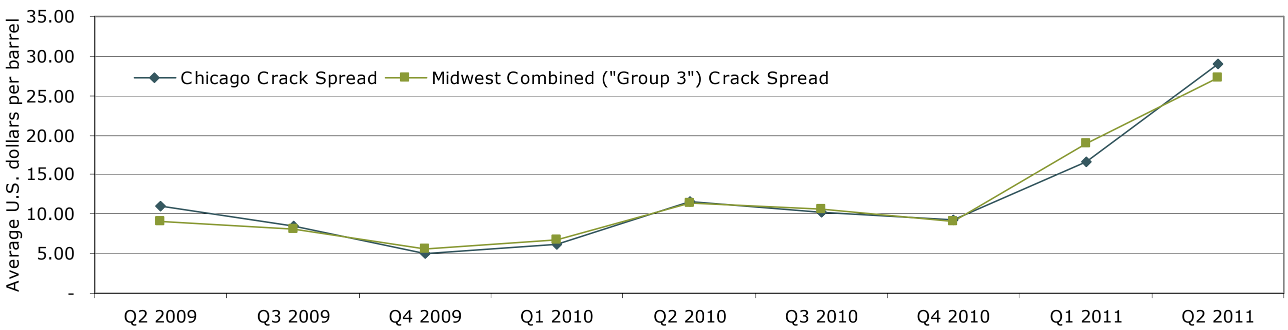
WTI is an important benchmark for Canadian crude since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The benchmark WTI price reached its highest level to date for 2011 in the second quarter at over US$113.00 per barrel before retreating to close the quarter under US$96.00 per barrel. The volatility within the second quarter was the result of uncertainty regarding the pace of global economic recovery and an uncertain response from OPEC in meeting Libyan supply outages. When compared to 2010, the average WTI benchmark prices have increased as they were impacted by the geopolitical conflict in Libya which resulted in a reduced supply of crude oil from the region. The demand for crude oil continued to rise in the second quarter of 2011 due to continued Asian demand primarily from China.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the second quarter of 2011 the WTI-WCS differential began to narrow as transportation issues that caused a widened differential in the first quarter of 2011 were mostly resolved and the Canadian inventory levels of WCS moderated. The demand for WCS also began to rise in the second quarter as refining capacity in the U.S. Midwest and Canada increased with a number of refineries returning to service after being down for repairs and maintenance. While the WTI-WCS differential showed improvements from the end of 2010 and the first quarter of 2011 it remains wide compared to the same period in 2010 due to continued growth in heavy crude supply and pipeline operational issues that impeded the flow of heavy crude oil out of Western Canada.




Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. As WTI discounts to offshore light crudes increased, condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland prices, and do not include an embedded inland discount included in the WTI benchmark price.

Crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices.




In the second quarter of 2011, benchmark NYMEX natural gas prices were higher than the same period in 2010. The increase in natural gas prices reflected the strong demand for natural gas due to unusually high nuclear maintenance outages and the early effects of reduced drilling levels on supply. The volumes of natural gas in storage during the second quarter decreased to below the five-year average levels.

During the second quarter of 2011, the Canadian dollar strengthened relative to the U.S. dollar, primarily driven by the increase in commodity prices. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a strengthened Canadian dollar reduces our reported results, although a stronger Canadian dollar reduces our refining capital investment.

## FINANCIAL INFORMATION

In 2011 we began reporting our financial results using our IFRS accounting policies. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been re-presented in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the interim Consolidated Financial Statements.

## SELECTED CONSOLIDATED FINANCIAL RESULTS

| ($ millions, except per share amounts) | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 | Q2 2011 | Q1 2011 | Q4 2010 | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | ***(Prepared following previous GAAP)*** | | |
| Revenues [1] | **7,509** | 6,316 | **4,009** | 3,500 | 3,363 | 2,962 | 3,094 | 3,222 | 3,005 | 3,001 | 2,818 |
| Operating Cash Flow [2] | **1,898** | 1,505 | **1,064** | 834 | 815 | 661 | 665 | 840 | 954 | 1,134 | 1,173 |
| Cash Flow [2] | **1,632** | 1,258 | **939** | 693 | 645 | 509 | 537 | 721 | 235 | 924 | 945 |
| - per share – diluted [3] | **2.15** | 1.67 | **1.24** | 0.91 | 0.85 | 0.68 | 0.71 | 0.96 | 0.31 | 1.23 | 1.26 |
| Operating Earnings [2] | **604** | 496 | **395** | 209 | 147 | 156 | 143 | 353 | 169 | 427 | 512 |
| - per share – diluted [3] | **0.80** | 0.66 | **0.52** | 0.28 | 0.19 | 0.21 | 0.19 | 0.47 | 0.23 | 0.57 | 0.68 |
| Net Earnings | **702** | 708 | **655** | 47 | 78 | 295 | 183 | 525 | 42 | 101 | 160 |
| - per share – basic [3] | **0.93** | 0.94 | **0.87** | 0.06 | 0.10 | 0.39 | 0.24 | 0.70 | 0.06 | 0.13 | 0.21 |
| - per share – diluted [3] | **0.93** | 0.94 | **0.86** | 0.06 | 0.10 | 0.39 | 0.24 | 0.70 | 0.06 | 0.13 | 0.21 |
| Capital Investment [4] | **1,189** | 935 | **476** | 713 | 701 | 479 | 444 | 491 | 507 | 515 | 488 |
| Free Cash Flow [2] | **443** | 323 | **463** | (20) | (56) | 30 | 93 | 230 | (272) | 409 | 457 |
| Cash Dividends [5] | **302** | 300 | **151** | 151 | 151 | 150 | 150 | 150 | 159 | n/a | n/a |
| - per share [5] | **0.40** | 0.40 | **0.20** | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | US$0.20 | n/a | n/a |

(1) Under previous GAAP, the amounts for 2009 represent Net revenues, which include the gains and losses on the revenue components of our risk management activities which are now reported in a separate line item.
(2) Non-GAAP measures defined within this MD&A.
(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's ("Encana") common share balances based on the terms of the plan of arrangement ("Arrangement") effective November 30, 2009 resulting in the split of Encana into Cenovus and Encana, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana for each share of Encana previously held.
(4) Includes expenditures on property, plant and equipment and exploration and evaluation assets.
(5) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

## REVENUES VARIANCE

| ($ millions) | Three Months Ended | Six Months Ended |
|---|---|---|
| Revenues for the Periods Ended June 30, 2010 | $ 3,094 | $ 6,316 |
| Increase (decrease) due to: | | |
| Oil Sands | 143 | 196 |
| Conventional | 43 | (83) |
| Refining and Marketing | 706 | 1,059 |
| Corporate and Eliminations | 23 | 21 |
| **Revenues for the Periods Ended June 30, 2011** | **$ 4,009** | **$ 7,509** |

Oil Sands revenues for the three months ended June 30, 2011 increased primarily due to higher average crude oil sales prices, higher condensate prices, decreased royalties at Foster Creek as a result of the ADOE's approval to include Foster Creek expansion phases F, G and H capital investment to date as part of our existing Foster Creek royalty calculation as well as decreased royalties at Pelican Lake from higher capital expenditures. Oil Sands revenues for the six months ended June 30, 2011 increased primarily due to higher average crude oil sales prices, higher condensate prices as well as decreased royalties at Pelican Lake as a result of higher capital expenditures. Partially offsetting the increases in both periods was the expected decrease in production because of the turnarounds at Foster Creek and Christina Lake and the temporary curtailment of production at Pelican Lake due to wild fires that disrupted pipeline transportation.

Our Conventional revenues increased in the second quarter of 2011 primarily due to increased average crude oil sales prices partially offset by decreased crude oil and NGLs production, expected declines in natural gas production and lower natural gas sales prices. The decrease in our Conventional revenues for the six months ended June 30, 2011 was primarily due to the decrease in natural gas production volumes and average sales prices partially offset by the increased average crude oil sales prices.

Our Refining and Marketing revenues in the second quarter of 2011 and for the six months ended June 30, 2011 increased primarily because of higher refined product prices as well as higher revenues related to operational third party sales undertaken by the marketing group.

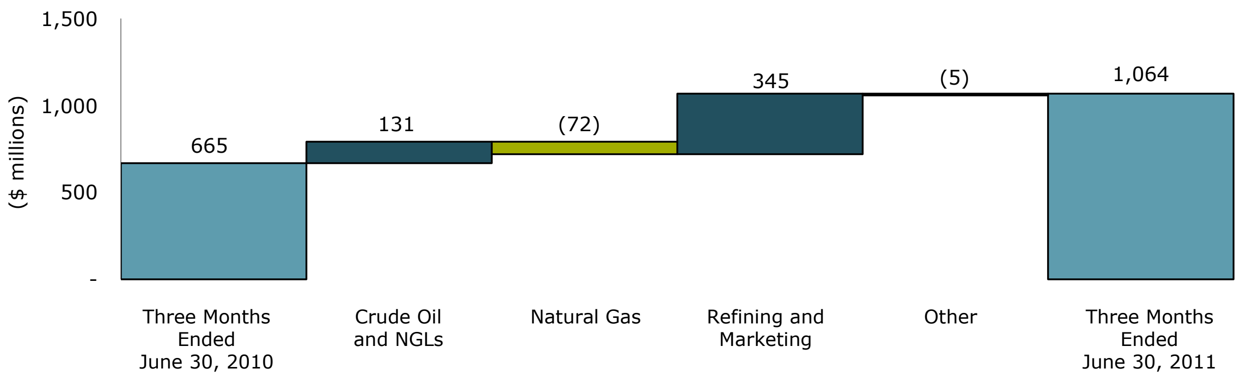
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

## OPERATING CASH FLOW

| | **Three Months Ended June 30,** | | **Six Months Ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Oil Sands | | | | |
| Crude Oil and NGLs | **$ 321** | $ 247 | **$ 571** | $ 546 |
| Natural Gas | **16** | 17 | **23** | 33 |
| Other | **2** | 5 | **4** | 5 |
| Conventional | | | | |
| Crude Oil and NGLs | **218** | 161 | **426** | 387 |
| Natural Gas | **181** | 252 | **366** | 551 |
| Other | **1** | 3 | **3** | 6 |
| Refining and Marketing | **325** | (20) | **505** | (23) |
| Operating Cash Flow | **$ 1,064** | $ 665 | **$ 1,898** | $ 1,505 |

Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.

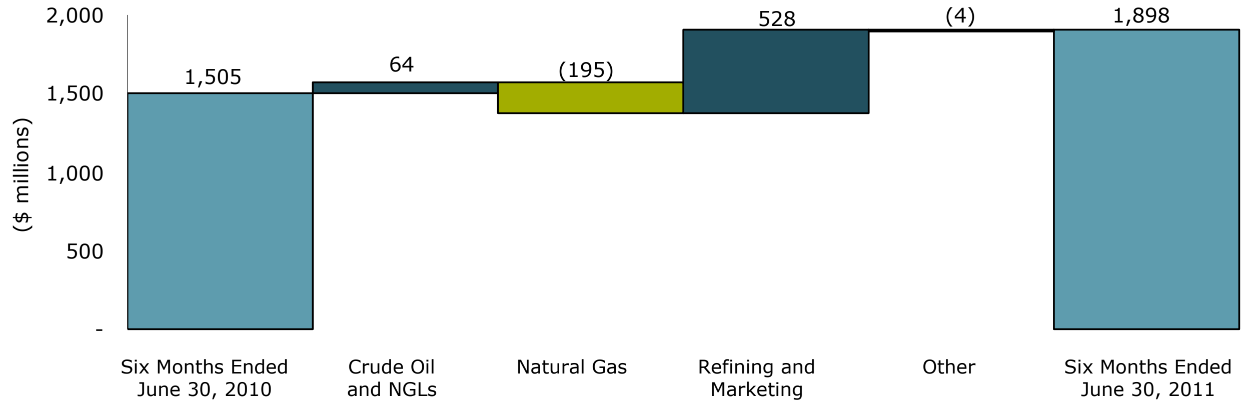
Three Months Ended June 30, 2011 compared to June 30, 2010




Operating cash flow increased $399 million in the second quarter of 2011 primarily because of a $345 million increase from Refining and Marketing attributable to improved refining margins. Operating cash flow generated by crude oil and NGLs increased $131 million in the second quarter of 2011 primarily due to higher average crude oil and NGLs sales prices and lower royalties partially offset by the temporary curtailment of production at Pelican Lake due to wild fires disrupting transportation, lower production at Foster Creek and Christina Lake due to scheduled turnarounds and flooding in southern Saskatchewan affecting our Weyburn, Bakken and Lower Shaunavon properties. The decrease in operating cash flow from natural gas was the result of lower sales prices and volumes, partly due to the divestiture of non-core natural gas properties in the third quarter of 2010.

Details of the components that explain the decrease in operating cash flow can be found in the Reportable Segments section of this MD&A.

Six Months Ended June 30, 2011 compared to June 30, 2010



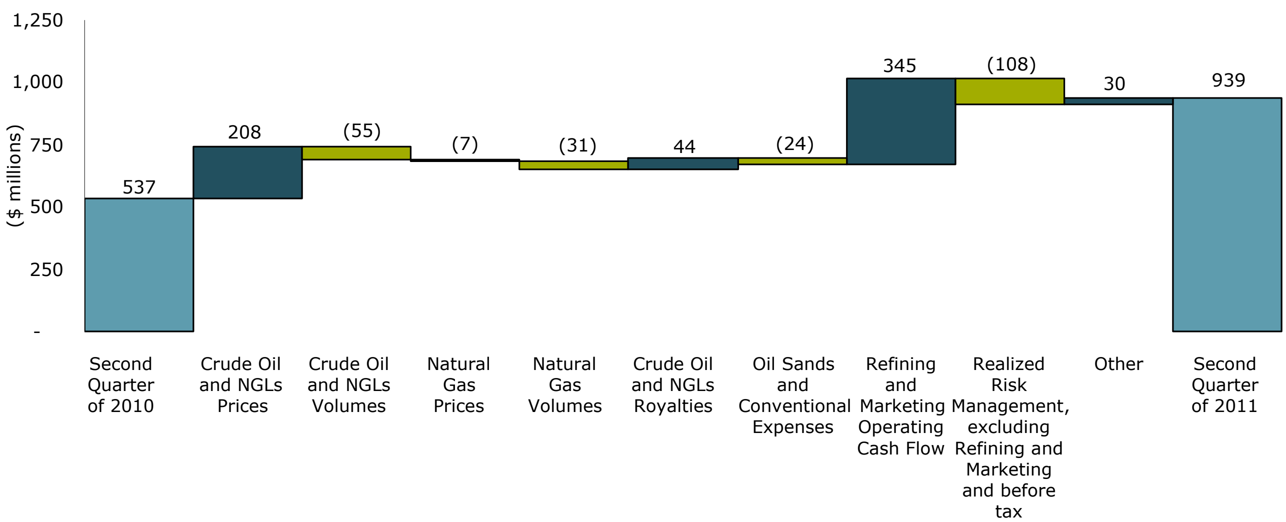

Operating cash flow in the first six months of 2011 increased $393 million primarily due to an increase of $528 million from Refining and Marketing due primarily to improved refining margins. Operating cash flow generated by crude oil and NGLs increased $64 million primarily due to increased average sales prices and lower royalties. These increases were partially offset by a $195 million reduction from natural gas due to decreased volumes, partly due to the divestiture of non-core natural gas properties in the third quarter of 2010, and decreased average sales prices.

## CASH FLOW

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Cash From Operating Activities | **$ 769** | $ 471 | **$ 1,400** | $ 1,291 |
| (Add back) deduct: | | | | |
| Net change in other assets and liabilities | **(16)** | (13) | **(45)** | (28) |
| Net change in non-cash working capital | **(154)** | (53) | **(187)** | 61 |
| Cash Flow | **$ 939** | $ 537 | **$ 1,632** | $ 1,258 |

Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

Three Months Ended June 30, 2011 compared to June 30, 2010



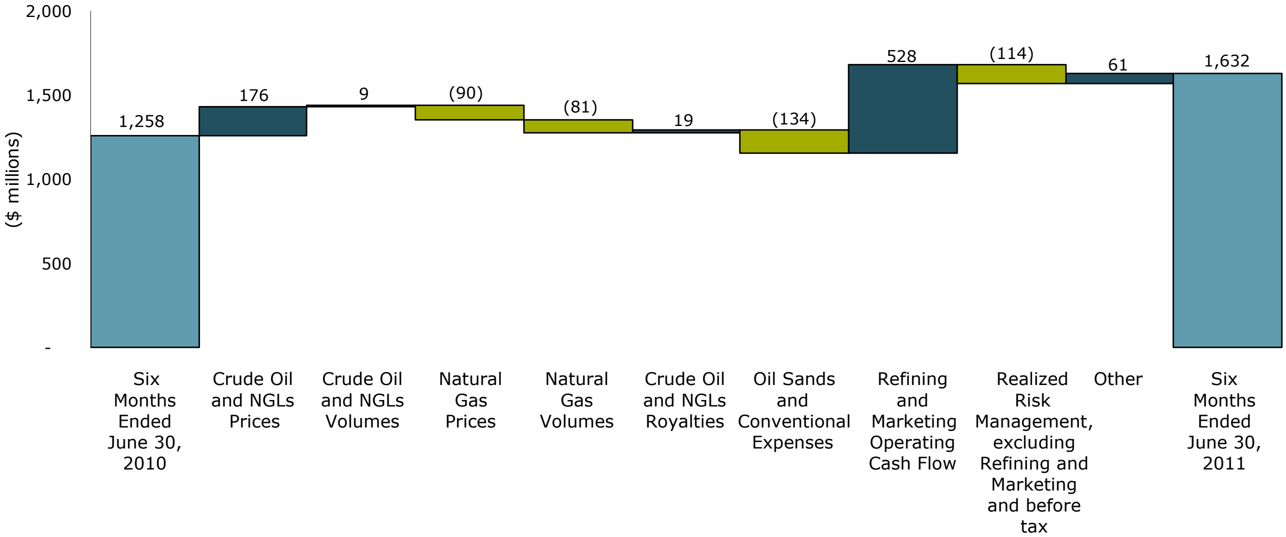
In the second quarter of 2011 our cash flow increased $402 million compared to the same period in 2010 primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $345 million, mainly due to improved refining margins;
- A 32 percent increase in the average sales price of crude oil and NGLs to $78.72 per barrel compared to $59.50 per barrel;
- A decrease in crude oil and NGLs royalties of $44 million mainly as a result of receiving ADOE approval for Foster Creek expansion phases F, G and H capital investment to date being included as part of our existing Foster Creek royalty calculation, partially offset by higher Canadian dollar equivalent WTI prices used to calculate royalty rates; and
- Lower general and administrative costs and interest expense.

The increases in our cash flow in the second quarter of 2011 were partially offset by:

- Realized hedging losses, before tax and excluding refining and marketing, of $29 million in the second quarter of 2011 compared to gains of $79 million in 2010;
- A five percent decrease in our crude oil and NGLs production volumes due to turnarounds at Foster Creek and Christina Lake, flooding in southern Saskatchewan, wild fires in Alberta and natural declines;
- Natural gas production declining 13 percent (97 MMcf/d), as a result of the divestiture of 41 MMcf/d in non-core properties in 2010, lower capital investment and expected natural declines; and
- A two percent decrease in the average natural gas sales price to $3.71 per Mcf compared to $3.78 per Mcf.

<u>Six Months Ended June 30, 2011 compared to June 30, 2010</u>




In the first half of 2011 our cash flow increased $374 million compared to the same period in 2010 primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $528 million, mainly due to improved refining margins;
- A 12 percent increase in the average sales price of crude oil and NGLs to $71.56 per barrel compared to $64.11 per barrel; and
- A decrease in crude oil and NGLs royalties of $19 million primarily as a result of decreased royalties at Pelican Lake due to higher capital investment partially offset by increased production at Foster Creek and Christina Lake and higher Canadian dollar WTI prices used to calculate royalty rates.

The increases in our cash flow for the first six months of 2011 were partially offset by:

- Realized hedging losses, before tax and excluding refining and marketing, of $10 million in 2011 compared to gains of $104 million in 2010;
- A 17 percent decrease in the average natural gas sales price to $3.76 per Mcf compared to $4.53 per Mcf;
- Natural gas production declining 14 percent, as a result of the divestiture of 41 MMcf/d in non-core properties in 2010, lower capital investment and expected natural declines;
- Higher crude oil and NGLs operating expenses mainly due to increased repairs and maintenance activities and turnaround costs, higher personnel as well as increased workovers at Foster Creek and Christina Lake; and
- A $24 million increase in current income tax expense as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010.

## OPERATING EARNINGS

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Net Earnings | **$ 655** | $ 183 | **$ 702** | $ 708 |
| (Add back) deduct: | | | | |
| Unrealized risk management gains (losses), after-tax (1) | **232** | 16 | **31** | 186 |
| Non-operating foreign exchange gains (losses), after-tax (2) | **26** | 14 | **65** | 16 |
| Gain (loss) on divestiture of assets, after-tax | **2** | 10 | **2** | 10 |
| Operating Earnings | **$ 395** | $ 143 | **$ 604** | $ 496 |

(1) The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized risk management gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange; after-tax effect of gains (losses) on divestiture of assets; and the effect of changes in statutory income tax rates.

We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods. The factors discussed in this MD&A that affected our cash flow and net earnings also impacted our operating earnings.

The increase in operating earnings in the second quarter and the first six months of 2011 is consistent with higher cash flow and lower depletion, depreciation and amortization ("DD&A") expense partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

## NET EARNINGS VARIANCE

| ($ millions) | Three Months Ended | Six Months Ended |
|---|---|---|
| Net Earnings for the Periods Ended June 30, 2010 | $ 183 | $ 708 |
| Increase (decrease) due to: | | |
| Operating Cash Flow | 399 | 393 |
| Corporate and Eliminations | | |
| Unrealized risk management gains (losses), net of tax | 216 | (155) |
| Unrealized foreign exchange gains (losses) | 57 | 61 |
| Expenses (1) | (22) | (91) |
| Depreciation, depletion and amortization | 43 | 66 |
| Income taxes, excluding income taxes on unrealized risk management gains (losses) | (221) | (280) |
| **Net Earnings for the Periods Ended June 30, 2011** | **$ 655** | **$ 702** |

(1) Includes general and administrative, interest income, finance costs, realized foreign exchange (gains) losses, gain (loss) on divestiture of assets, other (income) loss, net and Corporate operating expenses.

In the second quarter of 2011, our net earnings increased $472 million compared to the same period in 2010. The factors discussed above that increased our operating cash flow in the second quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 second quarter net earnings include:

- Unrealized risk management gains, after-tax, of $232 million, compared to gains of $16 million, after-tax, in the second quarter of 2010;
- Unrealized foreign exchange gains of $26 million in the second quarter of 2011 compared to losses of $31 million in 2010 consistent with the effects of the strengthened Canadian dollar on the translation of our long-term debt;
- Decreased general and administrative expenses primarily from lower long-term incentive expense;
- A decrease of $43 million in DD&A due to the addition of proved reserves at Foster Creek at the end of 2010 and lower production from our Conventional segment; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the second quarter of 2011 of $230 million, compared to $9 million for the same period in 2010.

In the first six months of 2011, our net earnings decreased $6 million compared to the same period in 2010. The factors discussed above that increased our operating cash flow in the first six months of 2011 also increased our net earnings. Other significant factors that impacted our net earnings in the first half of 2011 include:

- Unrealized risk management gains, after-tax, of $31 million, compared to gains of $186 million, after-tax, in 2010;
- Unrealized foreign exchange gains of $62 million in the first six months of 2011 compared to gains of $1 million in 2010 consistent with the effects of the strengthened Canadian dollar on the translation of our long-term debt;
- Increase of $58 million for general and administrative expenses primarily from higher long-term incentive expense with the increase in our share price from December 31, 2010;
- A decrease of $66 million in DD&A due to the addition of proved reserves at Foster Creek at the end of 2010 and lower production from our Conventional segment; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the first half of 2011 of $337 million, compared to $57 million for the same period in 2010.

## NET CAPITAL INVESTMENT

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Oil Sands | **$ 240** | $ 184 | **$ 644** | $ 368 |
| Conventional | **89** | 68 | **265** | 170 |
| Refining and Marketing | **117** | 166 | **219** | 370 |
| Corporate | **30** | 26 | **61** | 27 |
| Capital Investment | **476** | 444 | **1,189** | 935 |
| Acquisitions | **2** | 34 | **21** | 34 |
| Divestitures | **(5)** | (72) | **(9)** | (144) |
| Net Capital Investment [1] | **$ 473** | $ 406 | **$ 1,201** | $ 825 |

(1) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation assets ("E&E"). For purposes of managing our capital program, we do not differentiate between E&E and PP&E expenditures, and therefore we have not split our capital investment between E&E and PP&E within this MD&A.

Oil Sands capital investment in the second quarter and the first six months of 2011 included site preparation, facility engineering and infrastructure spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment included site preparation and facility construction for expansion phases C, D and E. We also drilled 440 gross stratigraphic wells during the first quarter of 2011, our largest program to date. The results of these stratigraphic wells will be used to support the expansion and development of our Oil Sands projects. Conventional capital investment in the second quarter and the first half of 2011 was primarily focused on the development of our crude oil properties. While our Conventional capital investment is ahead of last year, it remains behind plan due to flooding in southern Saskatchewan which has restricted access to our properties. Refining and Marketing capital investment in 2011 was primarily focused on the CORE project at the Wood River refinery.

Overall, our year to date capital investment in 2011 was $254 million more than the same period in 2010. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

## FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of free cash flow, defined as cash flow less capital investment, which excludes acquisitions and divestitures. Cash flow is a non-GAAP measure and is defined under the cash flow section of this MD&A.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Cash Flow | **$ 939** | $ 537 | **$ 1,632** | $ 1,258 |
| Capital Investment | **476** | 444 | **1,189** | 935 |
| Free Cash Flow | **$ 463** | $ 93 | **$ 443** | $ 323 |

The increases in our free cash flow for the second quarter and six months ended June 30, 2011 were directly due to the increases in our cash flow, discussed earlier in this section of the MD&A.

## RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

The realized risk management amounts in the summary tables below impact our operating cash flow, cash flow, operating earnings and net earnings while unrealized amounts only impact our net earnings. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

### Financial Impact of Risk Management Activities for the Three Months Ended June 30

| | **2011** | | | 2010 | | |
|---|---|---|---|---|---|---|
| ($ millions) | Realized | Unrealized(1) | Total | Realized | Unrealized(1) | Total |
| Crude Oil | **$ (70)** | **$ 325** | **$ 255** | $ (3) | $ 118 | $ 115 |
| Natural Gas | **45** | **(16)** | **29** | 83 | (98) | (15) |
| Refining | **(8)** | **(2)** | **(10)** | 9 | (1) | 8 |
| Power | **(4)** | **2** | **(2)** | 2 | 3 | 5 |
| Gains (losses) on Risk Management | **(37)** | **309** | **272** | 91 | 22 | 113 |
| Income Tax Expense (Recovery) | **(11)** | **77** | **66** | 26 | 6 | 32 |
| Gains (Losses) on Risk Management, after-tax | **$ (26)** | **$ 232** | **$ 206** | $ 65 | $ 16 | $ 81 |

(1) This is a non-cash item that is included in net earnings and affects the Corporate and Eliminations segment's financial results.

In the second quarter of 2011, this strategy resulted in realized gains on our natural gas financial instruments and realized losses on our crude oil financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and increasing WTI benchmark crude oil prices.

## Financial Impact of Risk Management Activities for the Six Months Ended June 30

| ($ millions) | **2011** Realized | **2011** Unrealized[1] | **2011** Total | 2010 Realized | 2010 Unrealized[1] | 2010 Total |
|---|---|---|---|---|---|---|
| Crude Oil | **$ (104)** | **$ 65** | **$ (39)** | $ (12) | $ 116 | $ 104 |
| Natural Gas | **97** | **(49)** | **48** | 120 | 145 | 265 |
| Refining | **(13)** | **1** | **(12)** | 9 | (1) | 8 |
| Power | **(3)** | **24** | **21** | (1) | (1) | (2) |
| Gains (losses) on Risk Management | **(23)** | **41** | **18** | 116 | 259 | 375 |
| Income Tax Expense (Recovery) | **(8)** | **10** | **2** | 34 | 73 | 107 |
| Gains (Losses) on Risk Management, after-tax | **$ (15)** | **$ 31** | **$ 16** | $ 82 | $ 186 | $ 268 |

(1) This is a non-cash item that is included in net earnings and affects the Corporate and Eliminations segment's financial results.

For the first six months of 2011, the realized gains on our natural gas financial instruments were lower than 2010 as a result of lower contract prices. Realized losses on our crude oil hedges increased consistent with the higher WTI benchmark crude oil prices.

## RESULTS OF OPERATIONS

### Crude Oil and NGLs Production Volumes

| (bbls/d) | **Q2 2011** | Q1 2011 | Q4 2010 | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 |
|---|---|---|---|---|---|---|---|---|---|
| Oil Sands | | | | | | | | | |
| Foster Creek | **50,373** | 57,744 | 52,183 | 50,269 | 51,010 | 51,126 | 47,017 | 40,367 | 34,729 |
| Christina Lake | **7,880** | 9,084 | 8,606 | 7,838 | 7,716 | 7,420 | 7,319 | 6,305 | 6,530 |
| Pelican Lake | **19,427** | 21,360 | 21,738 | 23,259 | 23,319 | 23,565 | 23,804 | 25,671 | 23,989 |
| Senlac | **-** | - | - | - | - | - | 2,221 | 5,080 | 2,574 |
| Conventional | | | | | | | | | |
| Heavy Oil | **15,378** | 16,447 | 16,553 | 16,921 | 16,205 | 16,962 | 17,127 | 18,073 | 18,074 |
| Light & Medium Oil | **27,617** | 31,539 | 29,323 | 28,608 | 29,150 | 30,320 | 30,644 | 29,749 | 30,189 |
| NGLs [1] | **1,087** | 1,181 | 1,190 | 1,172 | 1,166 | 1,156 | 1,183 | 1,242 | 1,184 |
| | **121,762** | 137,355 | 129,593 | 128,067 | 128,566 | 130,549 | 129,315 | 126,487 | 117,269 |

(1) NGLs include condensate volumes.

While our second quarter crude oil and NGLs production decreased five percent compared to 2010, six month production was consistent at 129,516 barrels per day (2010 – 129,551 barrels per day). The decrease in our second quarter production was primarily the result of scheduled turnarounds at Foster Creek and Christina Lake, the temporary curtailment of production at Pelican Lake due to wild fires disrupting pipeline transportation, flooding in southern Saskatchewan restricting access to our leases at Weyburn, Bakken and Lower Shaunavon, expected natural declines and the 2010 divestiture of non-core assets. Although our overall crude oil and NGLs production was lower in the second quarter, Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity. Our six month crude oil and NGLs production remained consistent with 2010 as increased production at Foster Creek and Christina Lake was offset by the temporary curtailment of production at Pelican Lake and the declines at our Conventional operations due to the flooding and wet weather in southern Saskatchewan and Alberta as well as poor winter weather in the first quarter of 2011, expected natural declines and the divestiture of non-core assets in 2010. Further information on the changes in our production can be found in the Reportable Segments section of this MD&A.

## Natural Gas Production Volumes

| (MMcf/d) | **Q2 2011** | Q1 2011 | Q4 2010 | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 |
|---|---|---|---|---|---|---|---|---|---|
| Conventional | **617** | 620 | 649 | 694 | 705 | 730 | 750 | 775 | 799 |
| Oil Sands | **37** | 32 | 39 | 44 | 46 | 45 | 47 | 55 | 57 |
| | **654** | 652 | 688 | 738 | 751 | 775 | 797 | 830 | 856 |

Natural gas production continues to trend as expected. Our 2011 natural gas production volumes declined by 13 percent (97 MMcf/d) in the second quarter to 654 MMcf/d compared to 2010. For the six months ended June 30, 2011 our production decreased 14 percent to 654 MMcf/d (2010 – 762 MMcf/d) from 2010. The declines in production volumes of natural gas were due to our strategic decision to restrict capital spending on our natural gas assets over the last two years in favour of increasing investment in crude oil projects. The decline is also consistent with our strategy to divest of non-core natural gas properties which had produced approximately 41 MMcf/d in the second quarter and first six months of 2010, which was approximately five percent of each period's production in 2010. Weather related issues including extreme cold in the first quarter and wet weather in the second quarter of 2011 also reduced our natural gas production.

## Operating Netbacks

| | **Three Months Ended June 30,** | | | |
|---|---|---|---|---|
| | **2011** | | 2010 | |
| | **Crude Oil & NGLs** ($/bbl) | **Natural Gas** ($/Mcf) | Crude Oil & NGLs ($/bbl) | Natural Gas ($/Mcf) |
| Price [1] | **$ 78.72** | **$ 3.71** | $ 59.50 | $ 3.78 |
| Royalties | **6.72** | **0.04** | 9.93 | 0.07 |
| Transportation and blending [1] | **2.33** | **0.14** | 1.94 | 0.15 |
| Operating expenses | **13.13** | **0.98** | 12.10 | 0.92 |
| Production and mineral taxes | **0.67** | **0.05** | 0.71 | (0.04) |
| Netback excluding Realized Risk Management | **55.87** | **2.50** | 34.82 | 2.68 |
| Realized Risk Management Gains (Losses) | **(6.44)** | **0.74** | (0.40) | 1.22 |
| Netback including Realized Risk Management | **$ 49.43** | **$ 3.24** | $ 34.42 | $ 3.90 |

(1) The crude oil and NGLs price and transportation and blending costs exclude $26.31 per barrel (2010 - $21.73 per barrel) of condensate purchases which is blended with heavy crude oil.

In the second quarter of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $21.05 per barrel from 2010 primarily due to increased sales prices which reflected the improved benchmark prices between the periods partially offset by a stronger Canadian dollar. Also increasing our crude oil and NGLs netback was a decrease in royalties at Foster Creek after receiving ADOE approval for expansion phases F, G and H to be included as part of our existing Foster Creek royalty calculation, which resulted in a reduction of about $65 million ($5.82 per barrel) in our royalty expense. In the second quarter of 2011 our average netback for natural gas, excluding realized risk management gains and losses, decreased by $0.18 per Mcf primarily as a result of higher production and mineral taxes and operating expenses and lower sales prices.

Operating Netbacks (continued)

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | **2011** | | 2010 | |
| | **Crude Oil & NGLs** | **Natural Gas** | Crude Oil & NGLs | Natural Gas |
| | ($/bbl) | ($/Mcf) | ($/bbl) | ($/Mcf) |
| Price [(1)] | **$ 71.56** | **$ 3.76** | $ 64.11 | $ 4.53 |
| Royalties | **8.47** | **0.06** | 9.37 | 0.11 |
| Transportation and blending [(1)] | **2.48** | **0.16** | 1.87 | 0.18 |
| Operating expenses | **13.29** | **1.09** | 11.72 | 0.93 |
| Production and mineral taxes | **0.50** | **0.05** | 0.65 | 0.02 |
| Netback excluding Realized Risk Management | **46.82** | **2.40** | 40.50 | 3.29 |
| Realized Risk Management Gains (Losses) | **(4.41)** | **0.82** | (0.58) | 0.87 |
| Netback including Realized Risk Management | **$ 42.41** | **$ 3.22** | $ 39.92 | $ 4.16 |

(1) The crude oil and NGLs price and transportation and blending costs exclude $25.58 per barrel (2010 - $21.94 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first six months of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $6.32 per barrel primarily due to increased sales prices consistent with higher benchmark prices and lower royalties partially offset by a stronger Canadian dollar. The lower royalties were primarily the result of higher capital investment at Pelican Lake. Our average netback for natural gas, excluding realized risk management gains and losses, decreased by $0.89 per Mcf primarily as a result of lower sales prices and increased operating expenses.

Further discussions on the items included in our operating netbacks are included in the Reportable Segments section of this MD&A. Further information on our risk management strategy can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

## REPORTABLE SEGMENTS

## OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in the second quarter of 2011 include:

- Completing scheduled turnarounds at Foster Creek and Christina Lake on time and on budget, while averaging production of 50,373 barrels per day at Foster Creek and 7,880 barrels per day at Christina Lake;
- Commencing steam injection at Christina Lake phase C with production expected to begin ahead of schedule in the third quarter of 2011;
- The temporary curtailment of production at Pelican Lake for approximately two weeks due to transportation disruptions caused by wild fires in Alberta resulting in a quarterly impact of approximately 2,100 barrels per day. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened;
- Receiving ADOE approval for Foster Creek expansion phases F, G and H capital investment to date being included as part of our existing Foster Creek royalty calculation, which resulted in a reduction of about $65 million in our royalty expense for the second quarter of 2011;
- Receiving approval from the ERCB for expansion phases E, F, and G at Christina Lake;
- Receiving partner approval for expansion phases F, G and H at Foster Creek and phase E at Christina Lake; and
- Updating our strategic plan which targets:
    - Increasing our expected gross production capacity at Foster Creek phases F, G and H by 5,000 barrels per day to 35,000 barrels per day per phase;
    - Accelerating the timelines for production at Foster Creek phases G and H by approximately one year and at Christina Lake phase D from the second quarter to the first quarter of 2013; and
    - Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016.

## OIL SANDS - CRUDE OIL

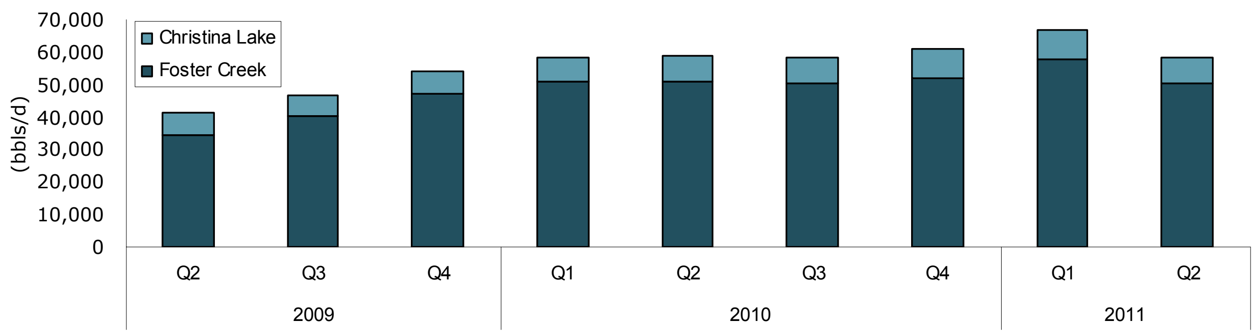
### Financial Results

| ($ millions) | Three Months Ended June 30, 2011 | 2010 | Six Months Ended June 30, 2011 | 2010 |
|---|---|---|---|---|
| Gross sales | **$ 766** | $ 672 | **$ 1,550** | $ 1,371 |
| Less: Royalties | **25** | 76 | **107** | 133 |
| Revenues | **741** | 596 | **1,443** | 1,238 |
| Expenses | | | | |
| Transportation and blending | **284** | 257 | **605** | 508 |
| Operating | **91** | 89 | **198** | 172 |
| (Gains) losses on risk management | **45** | 3 | **69** | 12 |
| Operating Cash Flow | **321** | 247 | **571** | 546 |
| Capital Investment | **239** | 183 | **629** | 365 |
| Operating Cash Flow in Excess (Deficient) of Related Capital Investment | **$ 82** | $ 64 | **$ (58)** | $ 181 |

### Production Volumes

| Crude oil *(bbls/d)* | Three Months Ended June 30, 2011 | 2011 vs 2010 | 2010 | Six Months Ended June 30, 2011 | 2011 vs 2010 | 2010 |
|---|---|---|---|---|---|---|
| Foster Creek | **50,373** | **-1%** | 51,010 | **54,038** | **6%** | 51,067 |
| Christina Lake | **7,880** | **2%** | 7,716 | **8,479** | **12%** | 7,569 |
| Subtotal | **58,253** | **-1%** | 58,726 | **62,517** | **7%** | 58,636 |
| Pelican Lake | **19,427** | **-17%** | 23,319 | **20,388** | **-13%** | 23,441 |
| | **77,680** | **-5%** | 82,045 | **82,905** | **1%** | 82,077 |

### Foster Creek and Christina Lake Production Volumes by Quarter




### Revenues Variance

Three Months Ended June 30, 2011 compared to 2010

| ($ millions) | Three Months Ended June 30, 2010 | Revenues Variances in: Price | Volume | Royalties | Condensate[1] | **Three Months Ended June 30, 2011** |
|---|---|---|---|---|---|---|
| Crude Oil | $ 596 | 111 | (43) | 51 | 26 | **$ 741** |

(1) Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In the second quarter of 2011, our average crude oil sales price increased 28 percent to $73.02 per barrel compared to the same period in 2010 consistent with the increase in the WCS benchmark price partially offset by the strengthening of the Canadian dollar.

Foster Creek production decreased slightly in the second quarter primarily as a result of a scheduled turnaround which decreased production by approximately 7,400 barrels per day. This was partially offset by improved plant efficiency and well performance due to less downtime and improvements in the steam to oil ratio. Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity. The two percent increase in production at Christina Lake was primarily the result of well optimizations and two new well pairs coming on production in the fourth quarter of 2010 partially offset by a scheduled turnaround which reduced production by approximately 800 barrels per day for the quarter. As a result of wild fires in the area, production at Pelican Lake was curtailed for approximately two weeks, including approximately seven days of complete shut-in which decreased production by approximately 2,100 barrels per day for the quarter. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened. Pelican Lake production was also impacted by expected natural declines which were partially offset by higher production due to polymer injection activities.

Royalties decreased in the second quarter of 2011 as a result of the ADOE approving the Foster Creek expansion phases F, G and H capital investment to date being included as part of the Foster Creek royalty calculation, which resulted in a reduction of about $65 million and Foster Creek's effective royalty rate decreasing to 3.3 percent (2010 – 19.0 percent). The decrease was partially offset by a higher Canadian dollar equivalent WTI price used for calculating royalty rates. In the second quarter of 2011, the effective royalty rate for Christina Lake was 6.3 percent (2010 – 4.4 percent) due to increased WTI prices. Pelican Lake royalties decreased mainly as a result of higher capital expenditures which resulted in an effective royalty rate of 9.7 percent (2010 – 23.3 percent).

Transportation and blending costs increased $27 million in the second quarter of 2011. The condensate portion of the increase ($26 million) was primarily the result of an increased average cost of condensate and was partially offset by lower volumes of condensate required due to decreased production at Foster Creek and Pelican Lake.

Operating costs increased slightly as the cost of turnarounds at Foster Creek and Christina Lake, higher repairs and maintenance activity and increased personnel were mostly offset by decreased chemical and waste handling costs.

Risk management activities in the second quarter of 2011 resulted in realized losses of $45 million compared to losses of $3 million in the second quarter of 2010.

Six Months Ended June 30, 2011 compared to 2010

| ($ millions) | Six Months Ended June 30, 2010 | Revenues Variances in: Price | Volume | Royalties | Condensate[1] | **Six Months Ended June 30, 2011** |
|---|---|---|---|---|---|---|
| Crude Oil | $ 1,238 | 83 | 10 | 26 | 86 | **$ 1,443** |

(1) Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In the first six months of 2011, our average crude oil sales price increased nine percent to $66.15 per barrel compared to the same period in 2010 consistent with the increase in the WCS benchmark price partially offset by the strengthening of the Canadian dollar.

Foster Creek production increased six percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio partially offset by the scheduled turnaround completed in the second quarter of 2011. The 12 percent increase in production at Christina Lake was the result of well optimizations and two well pairs coming on production in the fourth quarter of 2010 partially offset by a scheduled turnaround in the second quarter of 2011. At Pelican Lake, the temporary curtailment of production in the second quarter of 2011 resulted in a year to date decrease of approximately 1,000 barrels per day. Production was also impacted by natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalties decreased $26 million in the first half of 2011 primarily due to higher capital investment at Pelican Lake. Foster Creek royalties for the first six months of 2011 increased slightly as higher production and realized prices in 2011 combined with payout occurring in the first quarter of 2010 more than offset the approximately $65 million reduction in royalty expense resulting from the ADOE approval in the second quarter of 2011. The effective royalty rates for the first six months of 2011 were 11.9 percent at Foster Creek (2010 – 14.5 percent), 5.6 percent at Christina Lake (2010 – 4.2 percent) and 11.9 percent at Pelican Lake (2010 – 22.3 percent).

Transportation and blending costs increased $97 million in the first six months of 2011. The condensate portion of the increase was $86 million and was primarily the result of increases in the average cost of condensate and volumes of condensate required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $11 million primarily as a result of transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions combined with higher production volumes.

Operating costs increased $26 million due to the completion of turnarounds at Foster Creek and Christina Lake, increased personnel and higher long-term incentive expense partially offset by decreased fuel costs, waste handling and chemical costs. In addition, operating costs at Foster Creek and Christina Lake increased due to production increases, while Pelican Lake incurred higher polymer chemical costs.

Risk management activities for the six months ended June 30, 2011 resulted in realized losses of $69 million compared to losses of $12 million in 2010.

## OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of natural declines, our natural gas production decreased to 37 MMcf/d in the second quarter of 2011 (2010 – 46 MMcf/d) and to 35 MMcf/d for the six months ended June 30, 2011 (2010 – 45 MMcf/d). As a result of the decreased production and lower natural gas prices, operating cash flow declined $10 million for the six months ended June 30, 2011 but was consistent in the second quarter as the decreased volumes were offset by an improved average sales price for natural gas.

## OIL SANDS - CAPITAL INVESTMENT

| | **Three Months Ended June 30,** | | **Six Months Ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Foster Creek | **$ 77** | $ 52 | **$ 180** | $ 108 |
| Christina Lake | **121** | 85 | **229** | 148 |
| Subtotal | **198** | 137 | **409** | 256 |
| Pelican Lake | **31** | 28 | **115** | 50 |
| New Resource Plays | **9** | 11 | **103** | 50 |
| Other (1) | **2** | 8 | **17** | 12 |
| Capital Investment (2) | **$ 240** | $ 184 | **$ 644** | $ 368 |

(1) Includes Athabasca natural gas.
(2) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Oil Sands capital investment in 2011 has been primarily focused on the development of phases F, G and H at Foster Creek and phases C, D and E at Christina Lake, the drilling of stratigraphic test wells to support the development of our Oil Sands projects, as well as infill drilling activities related to our Pelican Lake polymer flood. We are on schedule to increase gross production capacity at Foster Creek and Christina Lake in 2013 to approximately 218,000 barrels per day of bitumen with the expected completion of Christina Lake phases C and D.

Foster Creek capital investment for the three and six months ended June 30, 2011 increased compared to the same periods in 2010 primarily as a result of increased spending on site preparation, facility engineering and infrastructure spending for expansion phases F, G and H. Foster Creek spending in the second quarter also included maintenance capital on our producing phases. Year to date capital investment included the drilling of stratigraphic test wells in the first quarter of 2011.

At Christina Lake, capital investment was higher in the second quarter of 2011 and the six months ended June 30, 2011 compared to the same periods in 2010 due primarily to the phase D and E expansions including site preparation and facility construction. Our year to date capital investment also increased due to the drilling of stratigraphic test wells in the first quarter of 2011 and additional capital maintenance requirements. We expect to increase gross production capacity to approximately 98,000 barrels per day with the completion of phases C and D. Phase C began injecting steam ahead of schedule in the second quarter of 2011 and we expect first production in the third quarter. First production at phase D is expected in the first quarter of 2013.

Capital investment for Pelican Lake for the three and six months ended June 30, 2011 was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities and maintenance programs. The facilities spending is focused on expanding capacity at Pelican Lake through additions and upgrades of our boiler units and emulsion pipelines.

Capital investment in new resource plays in 2011 was mainly related to the drilling of stratigraphic test wells and completion of seismic programs to support future oil sands projects. The results from the Grand Rapids pilot project are expected to give us a better understanding of the performance of SAGD in the formation.

### Stratigraphic Wells

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the first quarter of 2011. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. We also drilled a number of wells at Pelican Lake to address potential lease expiries. To minimize the impact on local infrastructure, the drilling of stratigraphic wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter. Therefore, in the second quarter of 2011, no stratigraphic wells were drilled (2010 – five wells).

| | **Six Months Ended June 30,** | |
|---|---|---|
| (gross stratigraphic wells drilled) | **2011** | 2010 |
| Foster Creek | **110** | 70 |
| Christina Lake | **59** | 24 |
| Subtotal | **169** | 94 |
| Pelican Lake | **57** | - |
| Narrows Lake | **41** | 35 |
| Grand Rapids | **45** | 33 |
| Borealis | **84** | 26 |
| Other | **44** | 15 |
| | **440** | 203 |

## CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future oil growth. We plan to assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in the second quarter of 2011 include:
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $158 million;
- Average production declining 2,200 barrels per day at our Weyburn operations primarily due to power outages and flooding which resulted in the shut-in of up to 150 production wells over the second half of June and interrupted the supply of carbon dioxide;
- Flooding restricting access to our Bakken and Lower Shaunavon properties which resulted in the shut-in of production reducing production by approximately 3,100 barrels per day, and also slowed development activities by restricting drilling activity in the quarter; and
- Updating our strategic plan which targets production of 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta by the end of 2016 as well as assessing the potential of new oil projects on our existing properties and new regions with a focus on tight oil opportunities.

## CONVENTIONAL - CRUDE OIL and NGLs

### Financial Results

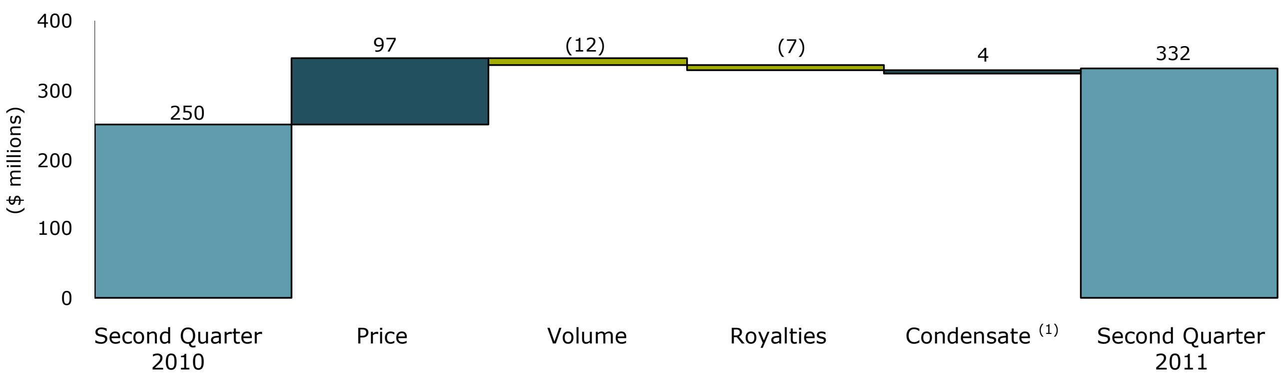
| ($ millions) | Three Months Ended June 30, 2011 | 2010 | Six Months Ended June 30, 2011 | 2010 |
|---|---|---|---|---|
| Gross sales | **$ 381** | $ 292 | **$ 737** | $ 643 |
| Less: Royalties | **49** | 42 | **93** | 86 |
| Revenues | **332** | 250 | **644** | 557 |
| Expenses | | | | |
| Transportation and blending | **28** | 23 | **55** | 49 |
| Operating | **51** | 57 | **114** | 103 |
| Production and mineral taxes | **7** | 8 | **12** | 15 |
| (Gains) losses on risk management | **28** | 1 | **37** | 3 |
| Operating Cash Flow | **218** | 161 | **426** | 387 |
| Capital Investment | **66** | 52 | **219** | 118 |
| Operating Cash Flow in Excess of Related Capital Investment | **$ 152** | $ 109 | **$ 207** | $ 269 |

### Production Volumes

| *(bbls/d)* | Three Months Ended June 30, 2011 | 2011 vs 2010 | 2010 | Six Months Ended June 30, 2011 | 2011 vs 2010 | 2010 |
|---|---|---|---|---|---|---|
| Heavy Oil | | | | | | |
| Alberta | **15,378** | **-5%** | 16,205 | **15,910** | **-4%** | 16,581 |
| Light and Medium Oil | | | | | | |
| Alberta | **10,289** | **-3%** | 10,645 | **10,804** | **-4%** | 11,246 |
| Saskatchewan | **17,328** | **-6%** | 18,505 | **18,763** | **1%** | 18,486 |
| NGLs | **1,087** | **-7%** | 1,166 | **1,134** | **-2%** | 1,161 |
| | **44,082** | **-5%** | 46,521 | **46,611** | **-2%** | 47,474 |

### Revenues Variance

Three Months Ended June 30, 2011 compared to 2010




(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

In the second quarter of 2011, our average crude oil and NGLs sales price increased 37 percent from $64.28 per barrel to $88.31 per barrel consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by the strengthened Canadian dollar. The Conventional segment produces light and medium crude oil in addition to heavy oil and therefore the average crude oil prices received in the Conventional segment benefited from lower average differentials.

Production in the second quarter of 2011 was lower than in 2010 primarily due to flooding in southern Saskatchewan which limited access to and shut-in production at our Bakken and Lower Shaunavon properties, and required us to partially shut-in production at our Weyburn operation for the second half of June. The flooding also caused the pipeline that supplies carbon dioxide to Weyburn to be temporarily shut down, although it is expected to be re-opened early in the third quarter. Production was further reduced in the second quarter of 2011 due to two power outages at Weyburn, the divestiture of approximately 464 barrels per day of production from non-core properties in 2010 as well as expected natural declines.

Royalties in the second quarter of 2011 increased by $7 million primarily due to increased crude oil prices partially offset by a strengthened Canadian dollar used for calculating royalty rates and decreased production, which resulted in an effective crude oil royalty rate of 14.5 percent (2010 – 14.6 percent).

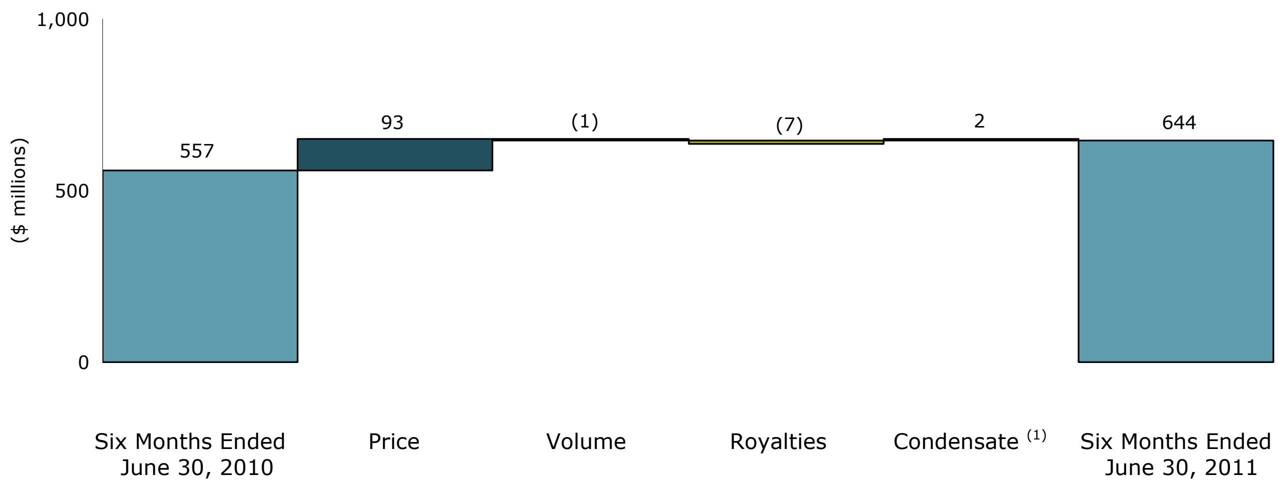
Transportation and blending costs increased $5 million in the second quarter of 2011 as increases in the average cost of condensate and higher pipeline costs were partially offset by a decrease in the volume of condensate required for blending.

Operating costs decreased $6 million in the second quarter of 2011 primarily due to lower workover activity which was the result of being unable to access our properties in southern Saskatchewan and decreased long-term incentive expense due to the decrease in our share price in the second quarter.

Risk management activities for the three months ended June 30, 2011 resulted in realized losses of $28 million compared to losses of $1 million in the second quarter of 2010.

Our Conventional crude oil and NGLs operating cash flow in excess of capital investment increased $43 million in the second quarter of 2011 compared to the same period in 2010 mainly due to increased crude oil and NGLs prices partially offset by lower production volumes and increased capital investment.

Six Months Ended June 30, 2011 compared to 2010




(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

In the first six months of 2011, our average crude oil and NGLs sales price increased 15 percent from $70.14 per barrel to $80.96 per barrel, consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by a strengthened Canadian dollar.

Production in the first half of 2011 was lower than in 2010 primarily due to flooding in southern Saskatchewan, which resulted in the shut-in of production at Bakken and Lower Shaunavon and the partial shut-in of production at Weyburn for the second half of June. Also decreasing our production was the 2010 divestiture of non-core properties that had produced approximately 895 barrels per day prior to their divestiture, expected natural declines and apportionment earlier in 2011.

Royalties for the six months ended June 30, 2011 increased by $7 million from the same period in 2010 as a result of increased prices partially offset by a strengthened Canadian dollar used for calculating royalty rates and decreased production, which resulted in an effective crude oil royalty rate of 14.0 percent (2010 – 14.6 percent).

Transportation and blending costs increased $6 million in the first half of 2011 as increases in the average cost of condensate and higher pipeline costs were partially offset by a decrease in the volume of condensate required for blending.

Operating costs increased $11 million in the first half of 2011 primarily due to higher repair and maintenance activity, increased electricity costs, higher salaries and benefits including long-term incentive expense and increased trucking costs. Partially offsetting these increases were lower chemical costs and decreased workover activity as we were unable to access some of our properties for part of the second quarter of 2011.

Risk Management activities in the first six months of 2011 resulted in realized risk management losses of $37 million compared to losses of $3 million in 2010.

Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $62 million in the first half of 2011 compared to the same period in 2010 due to increased capital investment in 2011 despite higher operating cash flow.

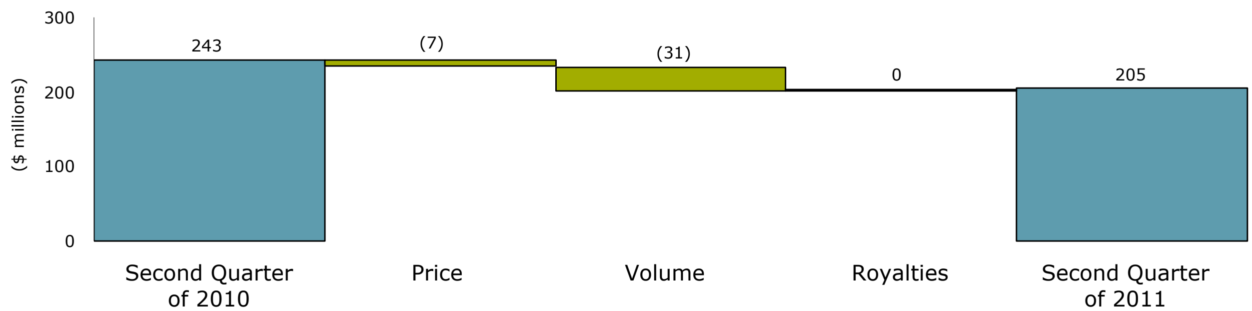
## CONVENTIONAL - NATURAL GAS

### Financial Results

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Gross sales | **$ 208** | $ 246 | **$ 422** | $ 593 |
| Less: Royalties | **3** | 3 | **6** | 9 |
| Revenues | **205** | 243 | **416** | 584 |
| Expenses | | | | |
| Transportation and blending | **8** | 10 | **18** | 24 |
| Operating | **53** | 59 | **114** | 115 |
| Production and mineral taxes | **3** | (2) | **6** | 3 |
| (Gains) losses on risk management | **(40)** | (76) | **(88)** | (109) |
| Operating Cash Flow | **181** | 252 | **366** | 551 |
| Capital Investment | **23** | 16 | **46** | 52 |
| Operating Cash Flow in Excess of Related Capital Investment | **$ 158** | $ 236 | **$ 320** | $ 499 |

### Revenues Variance

Three Months Ended June 30, 2011 compared to 2010




Our natural gas revenues and operating cash flow are lower in 2011 due to the cumulative impact of restricted natural gas capital spending over the last two years, divestitures of 41 MMcf/d of production from non-core properties in 2010 and restricted access due to the wet weather in southern Alberta, which resulted in a decrease in natural gas production volumes of 12 percent to 617 MMcf/d in the second quarter of 2011 (2010 – 705 MMcf/d).

Royalties were consistent in the second quarter of 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the second quarter of 2011 was 1.5 percent (2010 – 1.0 percent).

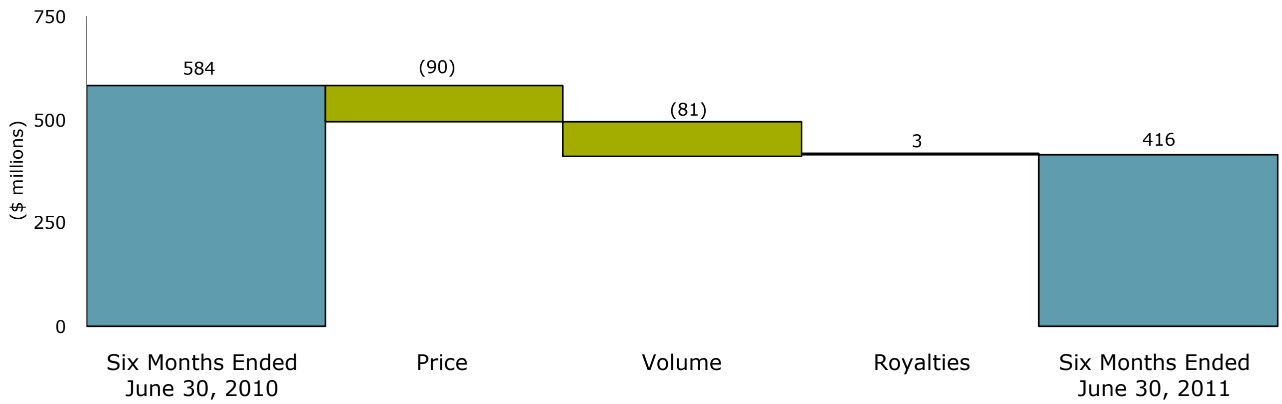
Costs related to transportation decreased by $2 million in the second quarter of 2011 due to lower production volumes.

Operating expenses for the second quarter of 2011 decreased by $6 million as a result of lower production volumes and reduced operations due to divestitures in 2010. Partially offsetting these decreases were increased repairs and maintenance activities.

Realized risk management activities in the second quarter of 2011 resulted in realized gains of $40 million, compared to gains of $76 million for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $78 million in the second quarter of 2011 compared to the same period in 2010 mainly due to lower average sales prices and production volumes in 2011.

Six Months Ended June 30, 2011 compared to 2010




Our natural gas revenues and operating cash flow are down in 2011 due to lower average sales prices, consistent with the change in the benchmark AECO price and lower production. The cumulative impact of restricted natural gas capital spending over the last two years, divestitures of 41 MMcf/d of production from non-core properties in 2010 and extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes of 14 percent to 619 MMcf/d for the six months ended 2011 (2010 – 717 MMcf/d).

Royalties decreased by $3 million for the six months ended June 30, 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the first half of 2011 was 1.4 percent (2010 – 1.5 percent).

Costs related to transportation decreased by $6 million in the first half of 2011 due to lower production volumes.

Operating expenses for the six months ended June 30, 2011 were consistent with 2010 as a result of higher long-term incentive expense and increased electricity costs which were offset by reduced operations due to divestitures in 2010 and lower production volumes.

Realized risk management activities resulted in realized gains in the first six months of 2011 of $88 million, compared to gains of $109 million for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $179 million in the first half of 2011 compared to the same period in 2010 mainly due to lower average sales prices and production volumes in 2011.

## CONVENTIONAL - CAPITAL INVESTMENT

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Crude Oil | **$ 66** | $ 52 | **$ 219** | $ 118 |
| Natural Gas | **23** | 16 | **46** | 52 |
| Capital Investment [1] | **$ 89** | $ 68 | **$ 265** | $ 170 |

(1) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Overall in 2011 our capital investment increased in our Conventional segment as part of our 2011 development strategy. Due to the flooding in southern Saskatchewan however, we remain behind in our 2011 planned capital investment. Capital investment on our crude oil properties was focused on drilling and facility work at Weyburn as well as appraisal projects and additional drilling in the Lower Shaunavon and Bakken areas. We reduced our natural gas capital investment in 2011 to focus investment on crude oil.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to Alberta CBM development.

| | **Six Months Ended June 30,** | |
|---|---|---|
| (net wells) | **2011** | 2010 |
| Crude oil | **105** | 50 |
| Natural gas | **15** | 78 |
| Recompletions | **546** | 409 |
| Stratigraphic test wells | **3** | 3 |

## REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Significant factors that impacted our Refining and Marketing segment include:
- Improved refining margins increased operating cash flow $345 million from the second quarter of 2010 and $528 million from the first six months of 2010;
- The progression of the CORE project to approximately 98 percent complete from 91 percent at the beginning of the year;
- Our refineries operating at 90 percent of capacity (year to date – 85 percent) producing 422 thousand barrels per day of refined products (year to date – 403 thousand barrels per day); and
- A storm related power outage resulted in operations at the Wood River refinery being fully interrupted on June 25, 2011. By the middle of July the refinery's utilization rate had recovered to its pre-storm level.

### Financial Results

| | **Three Months Ended June 30,** | | **Six Months Ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Revenues | **$ 2,725** | $ 2,019 | **$ 5,007** | $ 3,948 |
| Purchased product | **2,283** | 1,935 | **4,252** | 3,724 |
| Gross margin | **442** | 84 | **755** | 224 |
| Expenses | | | | |
| Operating expenses | **109** | 116 | **237** | 259 |
| (Gain) loss on risk management | **8** | (12) | **13** | (12) |
| Operating Cash Flow | **325** | (20) | **505** | (23) |
| Capital Investment | **117** | 166 | **219** | 370 |
| Operating Cash Flow in Excess (Deficient) of Capital Investment | **$ 208** | $ (186) | **$ 286** | $ (393) |

The gross margin for Refining and Marketing increased $358 million for the three months ended June 30, 2011 (year to date - increased $531 million) primarily due to increases in refined product prices which more than offset higher purchased product costs when compared to the same periods in 2010. Purchased product costs, which are determined on first-in, first-out inventory valuation basis, reflect the benefit of discounted heavy crude oil, and more recent discounts to U.S. inland crude oil. The benefit to our refining results of lower purchased product prices demonstrates our objective of economically integrating our heavy oil production. Gross margins for the second quarter of 2011 also reflected the impact of higher utilization when compared with the prior year.

Operating costs, consisting mainly of labour, utilities and supplies, decreased six percent in the second quarter of 2011 and decreased eight percent in the first six months of 2011 mainly due to lower refinery maintenance and turnaround costs and partially due to a stronger Canadian dollar.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $345 million in the second quarter and $528 million for the six months ended June 30, 2011 primarily due to the higher refining gross margins. This contrasts the second quarter and first six months of 2010 which were affected by weaker refined product prices, refinery optimization and planned turnarounds. Partially offsetting these increases to our operating cash flow in 2011 was a strengthened Canadian dollar.

## REFINERY OPERATIONS (1)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| Crude oil capacity *(Mbbls/d)* | **452** | 452 | **452** | 452 |
| Crude oil runs *(Mbbls/d)* | **406** | 379 | **384** | 367 |
| Crude utilization *(%)* | **90** | 84 | **85** | 81 |
| Refined products *(Mbbls/d)* | **422** | 398 | **403** | 388 |

(1) Represents 100% of the Wood River and Borger refinery operations.

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes again demonstrates our objective of economically integrating our heavy oil production.

Crude utilization in the second quarter of 2011, although affected by the outage at Wood River late in the quarter, improved in comparison to the same quarter of 2010. Prior year utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and planned turnarounds. Second quarter operating statistics also improved from the first quarter of 2011 levels, which were affected by operational and weather-related disruptions.

## REFINING AND MARKETING - CAPITAL INVESTMENT

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Wood River Refinery | **$ 104** | $ 140 | **$ 200** | $ 320 |
| Borger Refinery | **12** | 28 | **18** | 50 |
| Marketing | **1** | (2) | **1** | - |
| Capital Investment | **$ 117** | $ 166 | **$ 219** | $ 370 |

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River refinery. In the second quarter of 2011, of the $104 million capital expenditures at the Wood River refinery, $81 million were related to the CORE project. At June 30, 2011, the CORE project was approximately 98 percent complete with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.8 billion (US$1.9 billion net to Cenovus). The total estimated cost of the CORE project upon final completion in 2012 is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

The balance of the 2011 capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

## CORPORATE AND ELIMINATIONS

### Financial Results

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Revenues | **$ (15)** | $ (38) | **$ (41)** | $ (62) |
| Expenses ((add)/deduct) | | | | |
| Purchased product | **(15)** | (38) | **(41)** | (62) |
| Operating | **1** | (1) | **-** | (1) |
| (Gains) losses on risk management | **(309)** | (22) | **(41)** | (259) |
| | **$ 308** | $ 23 | **$ 41** | $ 260 |

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on long-term power purchase contracts.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| General and administrative | **$ 55** | $ 61 | **$ 168** | $ 110 |
| Finance costs | **106** | 121 | **223** | 246 |
| Interest income | **(31)** | (37) | **(63)** | (75) |
| Foreign exchange (gain) loss, net | **(6)** | 28 | **(29)** | 1 |
| (Gain) loss on divestitures | **(3)** | (14) | **(3)** | (14) |
| Other (income) loss, net | **1** | - | **-** | (1) |
| | **$ 122** | $ 159 | **$ 296** | $ 267 |

General and administrative expenses decreased $6 million in the second quarter of 2011 primarily due to lower long-term incentive expense caused by a lower share price partially offset by increased salaries and benefits and office support costs. For the six months ended June 30, 2011 our general and administrative expense increased $58 million which reflects increased costs of long-term incentives based on the increase of our share price year over year as well as increases in salaries and benefits and office support costs.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In the second quarter of 2011, our finance costs were $15 million lower (year to date – $23 million lower) than the same periods in 2010 primarily as a result of the strengthening Canadian dollar reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as it continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for the second quarter of 2011 was 5.2 percent (2010 – 5.7 percent) and for the six months ended June 30, 2011 was 5.4 percent (2010 – 5.8 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the second quarter of 2011 decreased by $6 million and decreased $12 million for the first six months of 2011 from the same periods in 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as it continues to be collected along with the strengthened Canadian dollar.

In the second quarter of 2011 we reported net foreign exchange gains of $6 million (2010 - losses of $28 million), of which $26 million were unrealized (2010 - $31 million). The strengthening of the Canadian dollar in the second quarter of 2011 led to unrealized gains on our U.S. dollar denominated long-term debt, which were partially offset by realized losses on our U.S. dollar denominated partnership contribution receivable. For the six months ended June 30, 2011 we recognized a foreign exchange gain of $29 million (2010 – loss of $1 million).

## DEPRECIATION, DEPLETION and AMORTIZATION

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Oil Sands | **$ 75** | $ 97 | **$ 161** | $ 189 |
| Conventional | **185** | 203 | **380** | 410 |
| Refining and Marketing | **18** | 21 | **34** | 45 |
| Corporate and Eliminations | **10** | 10 | **19** | 16 |
| | **$ 288** | $ 331 | **$ 594** | $ 660 |

Oil Sands DD&A decreased by $22 million in the second quarter of 2011 (year to date – $28 million) as increases in production volumes were offset by a lower DD&A rate at Foster Creek due to the significant addition of proved reserves at the end of 2010. The decrease in production volumes in our Conventional segment resulted in an $18 million reduction in DD&A in the second quarter and a year to date reduction of $30 million. Refining and Marketing DD&A in the second quarter and first six months of 2011 were lower primarily due to a strengthening of the average U.S./Canadian dollar exchange rate. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

## INCOME TAX EXPENSE

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Current tax | **$ 13** | $ 15 | **$ 54** | $ 30 |
| Deferred tax | **294** | - | **293** | 100 |
| Total | **$ 307** | $ 15 | **$ 347** | $ 130 |

When comparing the three months ended June 30, 2011 to the same period in 2010, our current tax expense was unchanged and our deferred tax expense increased. The increase in deferred tax expense was as a result of an increase in income from our Refining and Marketing segment and higher unrealized risk management gains.

When comparing the six months ended June 30, 2011 to the same period in 2010, both our current and deferred tax expense increased. The current tax expense increase is attributable to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception. The deferred tax expense increased as a result of increased income from our Refining and Marketing segment.

Our effective tax rate for the second quarter of 2011 was 32 percent (year to date – 33 percent) compared to 8 percent (year to date – 16 percent) in 2010. The increase in our effective tax rate is due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction and lower favourable permanent differences.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:

- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions) | Three Months Ended June 30, 2011 | Three Months Ended June 30, 2010 | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 |
|---|---|---|---|---|
| Net cash from (used in) | | | | |
| Operating activities | **$ 769** | $ 471 | **$ 1,400** | $ 1,291 |
| Investing activities | **(592)** | (468) | **(1,276)** | (840) |
| Net cash provided (used) before Financing activities | **177** | 3 | **124** | 451 |
| Financing activities | **(310)** | 16 | **(180)** | (187) |
| Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency | **(1)** | (7) | **1** | (10) |
| Increase (decrease) in cash and cash equivalents | **$ (134)** | $ 12 | **$ (55)** | $ 254 |

## OPERATING ACTIVITIES

Net cash from operating activities increased $298 million in the second quarter of 2011 (year to date – increase of $109 million) compared to the same period in 2010 mainly because of a $402 million increase (year to date – increase of $374 million) in cash flow, which is discussed in the Financial Information section of this MD&A, as well as an increased reduction of $101 million related to the net change in non-cash working capital (year to date – increased reduction of $248 million).

Excluding the impact of risk management assets and liabilities and assets held for sale, we had working capital of $359 million at June 30, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet the payment terms of our suppliers.

## INVESTING ACTIVITIES

Net cash used for investing activities in the second quarter of 2011 increased to $592 million from $468 million in 2010. Year to date net cash used in investing activities increased $436 million to $1,276 million. Total capital expenditures were $478 million in the second quarter of 2011 (2010 - $478 million) and year to date were $1,207 million (2010 - $969 million). Cash proceeds from divestitures in 2011 were $8 million (2010 - $144 million), $6 million of which occurred in the second quarter (2010 – proceeds of $72 million). The changes to our capital expenditures are discussed under the Net Capital Investment and Reportable Segments sections of this MD&A. The total net change in non-cash working capital resulted in a decrease of cash used in investing by $108 million in the second quarter of 2011 (2010 – decrease of $62 million) and $55 million year to date (2010 – decrease of $17 million).

## FINANCING ACTIVITIES

We have a $2.5 billion committed credit facility with a maturity date of November 30, 2014, and a commercial paper program, both of which can be used to manage our short-term cash requirements. At June 30, 2011, we had short-term borrowings in the form of commercial paper in the amount of $86 million. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

In the first and second quarters of 2011, we declared and paid a dividend of $0.20 per share (2010 – $0.20 per share) for total dividend payments of $302 million (2010 - $300 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities in the second quarter of 2011 was $310 million (2010 – cash generated of $16 million). For the six months ended June 30, 2011 net cash used in financing activities was $180 million (2010 – $187 million). The increase in net cash used in financing in the second quarter was primarily the result of the repayment of short-term borrowings of $166 million in 2011 compared to $164 million of commercial paper issuances in the second quarter of 2010. For the six months ended June 30, 2011 we had lower issuances on our short-term borrowings, decreased long-term debt repayments and higher proceeds on the issuance of common shares. Our long-term debt was $3,331 million as at June 30, 2011 and does not require any payments of principal until 2014.

As at June 30, 2011, we are in compliance with all of the terms of our debt agreements.

## FINANCIAL METRICS

| | **June 30, 2011** | December 31, 2010 |
|---|---|---|
| Debt to Capitalization | **28%** | 29% |
| Debt to Adjusted EBITDA (times) | **1.1x** | 1.3x |

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capitalization and debt to adjusted EBITDA. We define our non-GAAP measure of debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the partnership contribution payable or receivable. We define our non-GAAP measure of capitalization as debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss). These metrics are used to steward our overall debt position as measures of our overall financial strength.

In order to increase comparability of debt to adjusted EBITDA between periods and remove the non-cash component of risk management, we changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for prior periods have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

We continue to target a debt to capitalization ratio of between 30 to 40 percent and a debt to adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.

## OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at June 30, 2011 there were approximately 754.1 million common shares outstanding and no preferred shares outstanding.

## CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, future demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), building leases, capital commitments and marketing agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans.

## LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims.

# RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit and liquidity risk;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A and in the Risk Factors section of our Annual Information Form ("AIF") for the year ended December 31, 2010, available at www.cenovus.com.

## ENVIRONMENTAL REGULATION AND RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

### Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

Further information regarding Climate Change affecting Cenovus can be found in the Risk Management section of the December 31, 2010 MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

## ALBERTA'S REGULATORY FRAMEWORK

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers. The LARP will also identify areas related to conservation, tourism and recreation. Some of our lands are impacted by the designation of conservation, tourism and recreation areas; however, the areas identified have no direct impact on our 2011 strategic plan or on our current operations at Foster Creek or Christina Lake or any of our filed applications. If the draft land use designations for conservation, tourism and recreation areas are adopted in their current form, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta, and access to some parts of our current resource properties may be restricted. The lands identified for conservation, tourism and recreation areas are not currently included in our 2011 strategic plan. We will continue to monitor this matter through further consultation on the current draft of the LARP.

## TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy is available on our website at www.cenovus.com.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. In July 2011 we released our first comprehensive corporate responsibility report which can be found on our website at www.cenovus.com.

# ACCOUNTING POLICIES AND ESTIMATES

## ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and has not been re-presented in accordance with IFRS.

In each of our MD&As for 2010, as well as in our MD&A for the three months ended March 31, 2011, we included updates on the status of our IFRS conversion project, as well as detailed information on our IFRS accounting policies and elections, including the estimated impact of adopting the accounting policies. Our interim Consolidated Financial Statements for the six months ended June 30, 2011 include reconciliations from previous GAAP to IFRS that explain the significant impacts of adopting IFRS.

We concluded that the adoption of IFRS did not have a significant impact on any of our internal control processes. In terms of IFRS financial literacy, we continue to hold additional internal IFRS education sessions in 2011, and we plan to continue these sessions throughout 2011 to ensure that there is a strong level of knowledge of IFRS throughout our organization.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The following discussion highlights significant changes to our critical accounting policies and estimates from those disclosed in our MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

### E&E Assets

E&E costs are incurred when the legal right to explore has been obtained but before technical feasibility and commercial viability have been determined. The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material change in the future.

### Property, Plant and Equipment – DD&A

As a key component in the calculation of DD&A, the estimates of reserves at the area level can have a significant impact on net earnings, as a downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

### Asset Impairments

The assessment of facts and circumstances that are used for impairment testing to suggest that the carrying amount of the assets may exceed its recoverable amount is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or cash generating units ("CGUs") for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The estimate of a recoverable amount requires a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. These assumptions and estimates are subject to change as new information becomes available and changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's or CGU's carrying value.

### Exchanges of Assets

The estimate of fair value, which is used to recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

## Decommissioning Liabilities

Since the discount rate used to estimate our decommissioning liabilities is updated each reporting period under IFRS, changes in the credit-adjusted risk-free rate can affect the amount of the liability, and these changes could potentially be material in the future.

## Compensation Plans

As a result of measuring our obligations for payments under the Cenovus compensation plans at fair value under IFRS, fluctuations in the estimated fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on a number of assumptions, which include the risk-free interest rate, dividend yield and the volatility of our share price, and therefore the fair value of the obligation can fluctuate each reporting period.

# FUTURE CHANGES IN ACCOUNTING POLICIES

## IFRS Accounting Policies

Our IFRS consolidated financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore we have prepared our interim Consolidated Financial Statements using the standards that are expected to be effective at the end of 2011. However, our IFRS accounting policies will only be finalized when our first annual IFRS Consolidated Financial Statements are prepared for the year ending December 31, 2011. Therefore, certain accounting policies that we currently expect to follow under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified. As a result, our interim Consolidated Financial Statements for the six months ended June 30, 2011 are subject to change. Changes to the accounting policies used may result in material changes to our reported financial position, results of operations and cash flows.

## Joint Arrangements and Off Balance Sheet Activities

In May 2011, the IASB issued the following new and amended standards:

- *IFRS 10, "Consolidated Financial Statements"* ("IFRS 10") replaces *IAS 27, "Consolidated and Separate Financial Statements"* ("IAS 27") and Standing Interpretations Committee ("SIC") 12*, "Consolidation – Special Purpose Entities"*. IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.

- *IFRS 11, "Joint Arrangements"* ("IFRS 11") replaces *IAS 31, "Interest in Joint Ventures"* ("IAS 31") and *SIC 13, "Jointly Controlled Entities – Non-Monetary Contributions by Venturers"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts for the arrangement as an investment using the equity method.

- *IFRS 12, "Disclosure of Interest in Other Entities"* ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and *IAS 28, "Investments in Associates"*. It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- *IAS 27, "Separate Financial Statements"* has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

- *IAS 28, "Investments in Associates and Joint Ventures"* has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the five standards are adopted concurrently. We are currently evaluating the impact of adopting these standards on our Consolidated Financial Statements.

## Employee Benefits

In June 2011, the IASB amended *IAS 19, "Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates or the valuation of plan assets, will be recognized in OCI. Furthermore, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Earlier adoption is permitted. We are currently evaluating the impact of adopting these amendments on our Consolidated Financial Statements.

## Fair Value Measurement

In May 2011, the IASB issued *IFRS 13, "Fair Value Measurement"* ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. We are currently evaluating the impact of adopting IFRS 13 on our Consolidated Financial Statements.

## Financial Instruments

The IASB intends to replace *IAS 39, "Financial Instruments: Recognition and Measurement"* ("IAS 39") with *IFRS 9, "Financial Instruments"* ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2013 with different transitional arrangements depending on the date of initial application. We are currently evaluating the impact of adopting IFRS 9 on our Consolidated Financial Statements.

## Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to *IAS 1, "Presentation of Financial Statements"* ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting this amendment on our Consolidated Financial Statements.

## OUTLOOK

Our long-term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets along with additional debt financing for incremental cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core crude oil and natural gas assets;
- Maintain a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and
- Maintain a meaningful dividend with a priority expected to be placed on growing the dividend after 2011.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our financial results is discussed in the Risk Management section of this MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

The balance between robust demand growth and significant OPEC spare production capacity that kept WTI prices mostly between US$70.00 and US$90.00 per barrel beginning mid-2009 was broken in the first quarter of 2011 by the loss of over one million barrels per day of supply as hostilities escalated in Libya. The duration of these losses is uncertain but WTI prices are expected to adjust lower as this lost supply returns to the market or is offset by increased output from other OPEC countries. Demand growth should partially ease in response to current high prices but is expected to still remain near historic averages as prices have yet to materially weaken global Gross Domestic Product growth. The natural disaster in Japan could disrupt global supply chains, but once Japanese refining capacity returns to the market and rebuilding efforts commence combined with reduced nuclear energy output, it is expected that the demand for crude oil will increase.

Growth in Canadian heavy crude oil production and strong growth in inland light oil production have tested the capabilities of North America's pipeline grid. This has depressed inland prices for all crude grades relative to offshore crudes due to constraints in pipeline infrastructure. With inland product prices continuing to be set by U.S. Gulf Coast prices, this widening spread between discounted inland crude and elevated product prices has substantially improved refinery economics. With strong growth in inland crude supply expected to continue, pipeline capacity is expected to struggle to keep pace resulting in continued inland crude discounts.

We expect our 2011 capital investment program to be internally funded through cash flow based on the assumptions outlined in our current guidance. We also have sufficient capacity on our credit facilities for any incremental cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional natural gas assets in Alberta are key to providing free cash flow to enable crude oil growth. Updates to our business plan outline our targets of reaching net oil sands production of approximately 400,000 barrels per day by the end of 2021 and total net oil production of approximately 500,000 barrels per day by the end of 2021. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. This program increases revenue certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

# ADVISORY

## FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this MD&A is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology including technology and procedures to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form/Form 40-F for the year ended December 31, 2010, available at www.sedar.com, www.sec.gov and www.cenovus.com.

## CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one barrel. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

| Oil and Natural Gas Liquids | | Natural Gas | |
|---|---|---|---|
| bbl | Barrel | Mcf | thousand cubic feet |
| bbls/d | barrels per day | MMcf | million cubic feet |
| Mbbls/d | thousand barrels per day | MMcf/d | million cubic feet per day |
| MMbbls | million barrels | Bcf | billion cubic feet |
| NGLs | Natural gas liquids | MMBtu | million British thermal units |
| BOE | barrel of oil equivalent | GJ | Gigajoule |
| BOE/d | barrel of oil equivalent per day | CBM | Coal Bed Methane |
| WTI | West Texas Intermediate | | |
| WCS | Western Canada Select | | |

The Arrangement refers to the commencement of independent operations on December 1, 2009 following a plan of arrangement with Encana under the Canada Business Corporations Act to create two independent publicly traded energy companies.

## NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by GAAP such as cash flow, operating cash flow, free cash flow, operating earnings, adjusted EBITDA, debt and capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. The definition and reconciliation of each non-GAAP measure, is presented in this MD&A.

## ADDITIONAL INFORMATION

For convenience, references in this document to the "Company", "Cenovus", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("subsidiaries") of Cenovus, and the assets, activities and initiatives of such subsidiaries.

Additional information relating to Cenovus, including our AIF for the year ended December 31, 2010, is available on SEDAR at www.sedar.com and on our website at www.cenovus.com.