SUNCOR ENERGY INC. **2010** ANNUAL REPORT

# SUNCOR ENERGY

**SUNCOR ENERGY Inc. (Suncor)** is Canada's premier integrated energy company. Suncor's operations include oil sands development and upgrading, conventional and offshore oil and gas production, petroleum refining, and product marketing under the Petro-Canada brand. While working to develop petroleum resources responsibly, Suncor is also developing a growing renewable energy portfolio. Suncor's common shares (symbol: SU) are listed on the Toronto and New York stock exchanges.



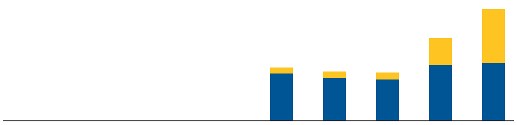
This Annual Report contains certain forward-looking statements and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends. All statements and other information that address expectations or projections about the future and other statements and information about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Forward-looking statements in this Annual Report include those identified in the "Legal Advisory – Forward Looking Information" section of our Management's Discussion and Analysis contained in this Annual Report as well as those contained in our "Message to Shareholders" and "Our Scorecard" contained in this Annual Report, including: Suncor's decade-long growth plan, and the expectation that it will boost Suncor's total production to more than one million barrels of oil equivalent per day by 2020; the expectation that the merger will result in $800 million in operational savings per year by 2012; Suncor's targeted net debt to cash flow from operations ratio of less than 2:1 in the years ahead; the forward-looking statements provided in "The Path Forward" in our Message to Shareholders, including our growth plans for Firebag and MacKay River, our strategic partnership with Total E&P Canada Ltd., and the expectation that the two companies with other partners will develop the Fort Hills mine and Joslyn mine and restart construction of the Voyageur Upgrader now slated for completion in 2016, our production targets (oil sands production growth of approximately 10% per year and company-wide production growth of approximately 8% per year through 2020), and the expectation that we will have the largest upgrading complex in Canada; anticipated capital spend for 2011; Suncor's strategic environmental performance goals; Suncor's $TRO_{TM}$ Technology; Suncor's target to achieve annual oil sands production of 280,000 to 310,000 barrels per day (excluding Syncrude) at a cash operating cost average of $39 to $43 per barrel; Suncor's plan to finance its 2011 capital spending mostly through internal cash flow, proceeds from the agreement with Total E&P Canada Ltd. and other potential asset divestitures; and the expectation that Suncor will continue to expand its St. Clair ethanol plant and bring two additional wind power projects on stream by the end of 2011. Forward-looking statements and information are not guarantees of future performance and involve a number of assumptions, risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and information and readers are cautioned not to place undue reliance on them.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout the Management's Discussion and Analysis included in this Annual Report and in Suncor's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities.

Certain crude oil and natural gas liquids (NGL) volumes have been converted to thousands of cubic fee equivalent (mcfe) and millions of cubic feet equivalent (mmcfe) of natural gas on the basis of one barrel (bbl) to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe), thousands of boe (mboe) and millions of boe (mmboe) on the same basis. Mcfe, mmcfe, boe, mboe and mmboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

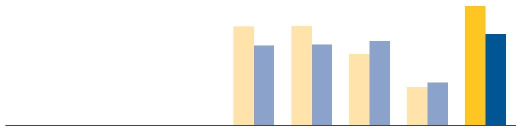
# FINANCIAL HIGHLIGHTS

### Production
(thousands of barrels of oil equivalent per day)



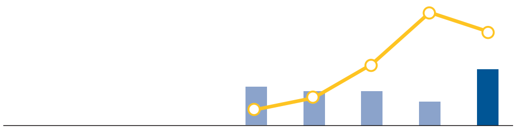
| | 06 | 07 | 08 | 09 | **10** |
|---|---|---|---|---|---|
| Natural Gas and International and Offshore | 34.8 | 35.8 | 36.7 | 149.3 | **296.9** |
| Oil Sands (including Syncrude) | 260.0 | 235.6 | 228.0 | 306.7 | **318.2** |
| Total | 294.8 | 271.4 | 264.7 | 456.0 | **615.1** |

### Earnings
($ millions)



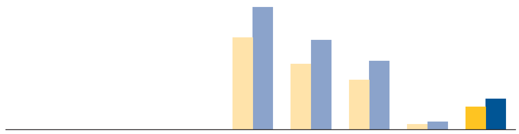
| | 06 | 07 | 08 | 09 | **10** |
|---|---|---|---|---|---|
| Net earnings | 2 969 | 2 983 | 2 137 | 1 146 | **3 571** |
| Operating earnings(1) | 2 389 | 2 425 | 2 534 | 1 280 | **2 732** |

### Cash Flow from Operations(1)/Net Debt
($ millions)



| | 06 | 07 | 08 | 09 | **10** |
|---|---|---|---|---|---|
| Cash flow from operations | 4 546 | 4 037 | 4 057 | 2 799 | **6 656** |
| Net debt | 1 849 | 3 248 | 7 226 | 13 377 | **11 112** |

### Return on Capital Employed(1)
(per cent)



| | 06 | 07 | 08 | 09 | **10** |
|---|---|---|---|---|---|
| ROCE(2) | 30.1 | 21.5 | 16.3 | 1.8 | **7.4** |
| ROCE(3) | 40.0 | 29.3 | 22.5 | 2.6 | **10.1** |

### Other Key Indicators

| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Financial | | | | | |
| Revenues (net of royalties) | **35 220** | 25 480 | 28 637 | 17 314 | 14 976 |
| Capital and exploration expenditures | **6 010** | 4 267 | 8 020 | 5 629 | 3 695 |
| Total assets | **70 169** | 69 746 | 32 528 | 24 509 | 18 959 |
| Dollars per Common Share | | | | | |
| Net earnings – basic | **2.29** | 0.96 | 2.29 | 3.23 | 3.23 |
| Net earnings – diluted | **2.27** | 0.95 | 2.26 | 3.17 | 3.16 |
| Cash flow from operations (1) | **4.26** | 2.34 | 4.36 | 4.38 | 4.95 |
| Cash dividends | **0.40** | 0.30 | 0.20 | 0.19 | 0.15 |
| Market Price of Common Stock at December 31 (Closing) | | | | | |
| Toronto Stock Exchange (Cdn$) | **38.28** | 37.21 | 23.72 | 53.96 | 45.90 |
| New York Stock Exchange (US$) | **38.29** | 35.31 | 19.50 | 54.37 | 39.46 |
| Key Ratios | | | | | |
| Total debt to total debt plus shareholders' equity (%) | **25** | 29 | 35 | 24 | 21 |
| Net debt to cash flow from operations (times) | **1.7** | 4.8 | 1.8 | 0.8 | 0.4 |
| Return on shareholders' equity (%) | **10.2** | 5.1 | 16.2 | 28.4 | 39.0 |

The 2009 financial highlights include the results of Suncor after the merger with Petro-Canada from August 1, 2009. As such, the amounts reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor (not including Petro-Canada) only from January 1, 2009 through July 31, 2009. The 2010 financial highlights reflect an entire year of post-merger Suncor results. Comparative figures prior to 2009 reflect solely the results of legacy Suncor.

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of Suncor's 2010 Management's Discussion and Analysis.

(2) Includes capitalized costs related to major projects in progress.

(3) Excludes capitalized costs related to major projects in progress.

# MESSAGE TO SHAREHOLDERS

For more than four decades, Suncor Energy has distinguished itself by being bold and forward-looking. In 1967, our company pioneered oil sands development at a time when many observers believed the resource could never be commercially viable. In the late 1990s, we opted to expand oil sands production dramatically even though world oil prices then languished at less than $15 per barrel. In 2009, with the energy industry and the larger economy still reeling from a global credit crisis and volatile commodity prices, we embarked on an ambitious merger with Petro-Canada to create Canada's largest integrated energy company. All of these moves, each in their own way, seemed counterintuitive. But all supported Suncor's central strategy – to build strong and enduring shareholder value by focusing on a long-term vision and finding innovative ways to produce the energy our economy requires responsibly.

Seen in this context, 2010 marked a pivotal year in Suncor's history. It was the year we fully implemented the successful merger of two progressive energy companies and began to realize the resulting synergies and savings. It was also the year we launched Suncor on a new decade-long growth plan, expected to boost our total production to more than one million barrels of oil equivalent per day by 2020, which reinforces our leading position in developing the Athabasca oil sands and continues to leverage our geographical breadth and vertical integration of assets into a single, focused strategy.

The merger strengthened our integrated strategy, providing Suncor with an even stronger set of assets that, in the years and decades ahead, will help support the growth and development of our core resource.

### Coming Together

Today's Suncor combines a leading position in the oil sands with expanded operations in refining and marketing, North American natural gas production and lower cost oil and gas production internationally and offshore East Coast Canada. We now enjoy a stronger balance sheet, more robust earnings and cash flow from operations, and the capacity to strategically invest in an impressive suite of growth opportunities.

The merger resulted in annual capital efficiencies of an estimated $1 billion. Operational synergies, originally targeted at $300 million per year, are now expected to grow to approximately $800 million per year by 2012.

By the end of 2010, we had sold approximately $3.5 billion of assets that did not support our long-term strategy. The net proceeds from the completed sales helped reduce the company's net debt, from $13.4 billion to just a little over $11 billion by year's end.

Significantly improved cash flow is now helping us to finance our medium term capital spending internally – something that should help us maintain our net debt to cash flow from operations ratio at the target of less than 2:1 in the years ahead.

We also saw improved reliability across our operations in 2010. At Oil Sands, we exceeded our targeted annual production average of 280,000 barrels per day (excluding Syncrude) even as Suncor completed significant planned maintenance on one of our upgraders, while record fourth quarter production of more than 325,000 barrels per day (excluding Syncrude) set a strong foundation for 2011. In the downstream, we were able to mitigate the impact of third-party pipeline interruptions by sourcing crudes from alternative suppliers and re-routing some of our oil sands production to our own oil sands-integrated refineries and to other customers.

All of these achievements suggest that the corporate-wide operational excellence program led by Suncor's Chief Operating Officer, Steve Williams, is paying substantial dividends – particularly over the past 12 months. In an organization as large as Suncor, ensuring safe, reliable, environmentally responsible and cost-effective performance across existing operations isn't about doing one thing right one time – it's about doing a thousand things right all of the time. It requires rigorous management and constant oversight.

I'm very proud of all the hard work by Suncor's management and employees, who are helping us fully realize the synergies of a game-changing merger, while also making continuous improvement in our operational performance. We intend to build on this foundation of success as we enter an exciting new chapter in the Suncor story.

### The Path Forward

While 2010 was about transforming Suncor into a stronger and more flexible corporate entity that could compete with the global energy super-majors, 2011 and beyond will be largely about maintaining reliable performance while returning to growth, improving return on capital employed and driving superior shareholder value.

The 10-year growth strategy we announced in December 2010 reflects the next major steps as we continue to develop Suncor's resource base from the oil sands. Our massive known resource base provides us with an outstanding suite of growth options and a remarkable opportunity to carefully map out long-term development without the need for any further exploration.

Our growth plan for the next decade includes continued development of our in situ oil sands resources. Strong performance from these assets will be key in both the near and longer term. In the near term, focus on higher volumes from our Firebag in situ oil sands operations will better leverage existing capital investments. Carrying that performance focus forward will also be central as we add four additional stages at Firebag and expand our MacKay River in situ project, all by 2020.

Our growth plan also notably features a strategic partnership with Total E&P Canada Ltd. (Total), a company with capabilities and resources that complement our own and one that shares our vision of responsible energy development.

Together, the two companies plan to develop two key oil sands mining projects with other partners – the Fort Hills mine, which will be operated by Suncor, and the Joslyn mine, which will be operated by Total. Together, we are also restarting construction of the 200,000 barrel per day Voyageur Upgrader at Suncor's oil sands operations north of Fort McMurray, Alberta, now slated for completion in 2016.

The partnership with Total should also help us with another potential challenge as Suncor, along with the rest of the oil sands industry, enters a new growth phase. No one wants to return to the overheated days of pre-2008 when companies scrambled for scarce labour resources and faced hyper-inflated material costs. Instead of competing on separate upgraders and mine projects, Suncor and Total should be able to take a balanced approach to project work, avoiding some of the peaks and valleys of industry-wide labour demand that we would otherwise have seen. To support these goals, we have launched a dedicated organization, separate from our existing oil sands business, charged with the planning and execution of this critical part of our growth strategy.

With this full portfolio of oil sands growth plans, Suncor is targeting average oil sands production growth of approximately 10% per year and company-wide production growth of approximately 8% per year through to 2020 – rates that significantly outperform most major energy companies. This is an ambitious goal and to fully realize the best returns for our investments, execution of engineering, procurement and construction will be critical in the build phase – combined with a sharp focus on costs as projects come into operation.

Of Suncor's one million barrels per day of oil equivalent production expected by 2020, it is planned that approximately four of every five barrels will flow from the oil sands. The additional production will come from a prudent balance of in situ and mining projects, providing internal diversification, given the different capital and operating cost structures and potential technology advances associated with these two recovery methods.

As our strategy unfolds, we also expect to have the largest upgrading complex in Canada, with options to either upgrade product ourselves or send it straight to market, again reflecting the benefits of a flexible approach to our business.

Outside of the oil sands, we are targeting modest production growth in our conventional Exploration and Production division. This newly minted business combines our offshore, international, and North American onshore operations. The combined business brings the benefit of better leveraging conventional development expertise and support structures across the company and providing lower cost production with increased cash flow. With some 200,000 barrels per day of oil equivalent production in 2010 that was linked to Brent crude benchmarks, we also saw a built-in balance to widening differences between Brent's offshore based benchmark and WTI, a North American inland benchmark.

In the downstream, we will continue to integrate oil sands products into our refining and marketing operations. An integrated refining and marketing business softens the swings of commodity price cycles, changing light/heavy oil differentials and other market impacts that are not within our control. This advantage became clear in the latter part of 2010.

At the same time, we will bring forward additional renewable energy projects and maintain our position as one of Canada's leading investors in this growing energy sector.

As we move forward, we have some clear financial goals – to improve return on capital employed, increase cash flow, maintain a healthy balance sheet and drive shareholder value. We have done foundational work on several fronts in the last year that already puts us in a great position to attain these goals.

## Sustainable Development

As Suncor resumes growing, we intend to remain true to our long-standing vision of a triple bottom line. That means we must continue to manage our business in ways that enhance social and economic benefits, while striving to minimize the environmental impacts associated with energy development.

In 2010, Suncor marked some significant milestones on our journey toward sustainable development.

In September, Suncor became the first oil sands company to complete surface reclamation of a tailings pond. As a result, our original Pond 1, now known as Wapisiw Lookout, is on track to be returned to natural forest and wetlands habitat.

This achievement was a source of pride for all of us at Suncor. It also reinforced my strong belief that, when it comes to environmental leadership, actions always speak louder than words. We promised to be the first oil sands company to do this – and we delivered.

In that same spirit, Suncor expects to spend more than $1 billion over 2010 to 2012 to implement a new tailings and reclamation technology at our existing operations. This represents a significant step forward in addressing one of the biggest environmental challenges facing our industry.

This technology has already enabled us to cancel plans for five additional tailings ponds. In the years ahead, we expect it will help us reduce the number of tailings ponds at our current mine site from eight to one, allowing us to reclaim entire mine sites in about a third of the time it now takes – resulting in more rapid restoration of natural habitats.

Because tailings management is such a pressing industry-wide challenge, all seven oil sands companies currently running mine operations recently committed to an unprecedented level of collaboration on this issue. Suncor, for its part, has taken a leadership position, and we have agreed to share our technology with industry competitors as well as university and government scientists so the environmental benefits of this game-changing innovation can be maximized.

The progress we are making on the tailings front is something I believe our industry can repeat in a number of areas – including managing greenhouse gas emissions, further reducing water use and finding more efficient ways to power our operations.

But it will require all of us to do much more, both within our own plant gates and through further collaboration. This commitment to innovation and bold thinking has always been the foundation of Suncor's success – and I'm convinced it's what the future of this company, and this industry, is all about.

### A Team Effort

As in the past, everything our company hopes to achieve going forward begins and ends with the expertise and commitment of Suncor's employees – a talented team of professionals who are always up for the next great challenge.

I also remain indebted to Suncor's Board of Directors, who oversee all aspects of governance and are outstanding stewards of stakeholders' interests. They excel at challenging management to lead, innovate and grow our company – and I want to recognize them for their guidance and support. On behalf of Suncor's management, I also wish to thank Brian Canfield, who will be retiring this year from the Board after more than 15 years of service, for his dedication and significant contributions to Suncor's success.

Together, we are embarking on the most exciting chapter yet in Suncor's history, one that is aimed at helping us realize the full value of our company and the unparalleled resource base we have the privilege of developing. We know we have substantial work ahead of us to meet the expectations of our shareholders – and all our stakeholders – but we welcome the challenge. As always, I am grateful to be part of this collective effort and, on behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support.

Rick George

**Rick George**
president and chief executive officer

In late February, civil unrest swept Libya, where Suncor has both oil production and exploration activities. At the time of filing this report, the degree and duration of impact on our business is not known. Our focus has been on the safety of our people – expatriate and Libyan national staff, and the contractors and service providers supporting Suncor's operations.

## OUR SCORECARD[1]

### Long-term performance

- **Value at December 31, 2010 of $100 invested in Suncor on March 18, 1992 when the company became publicly traded: $5,174.** Value at December 31, 2010 of $100 invested in the Standard & Poor's 500 on March 18, 1992: $373.[2]
- **Greenhouse gas intensity (per unit of production) at our oil sands business in 2009 compared with 1990:** 53.6% reduction.
- **Percentage of total water use at our oil sands business in 2009 compared with 2004:** 72.5% water withdrawal from the Athabasca River is at its lowest since 1998, while bitumen production has nearly tripled.
- **Strategic environmental performance goals as our production rates grow**[3]
  - Reduce total water intake by 12% by 2015
  - Increase land area reclaimed by 100% by 2015
  - Improve energy efficiency by 10% by 2015
  - Reduce air emissions by 10% by 2015

### 2010 – Our goals and how we delivered

- **Operational excellence.** We advanced strategies focused on operational excellence aimed at further improving personal and process safety and reliability. Our safety performance continued to improve as we adopted a clear set of process safety management standards and implemented it at all facilities. We saw a strong full-year performance in the company's international, offshore and refining operations, and continual improvements in the reliability of our oil sands operations, leading to record production in the fourth quarter.
- **Continue efforts to reduce environmental impact intensity.** We reclaimed the industry's first tailings pond to a trafficable surface in 2010. As well, we received approval and started implementation of a new tailings technology, $TRO_{TM}$, which we expect will reduce tailings reclamation time by decades and already enabled the cancellation of plans to build five additional tailings ponds at our existing operations.
- **Strengthen balance sheet and maintain investment grade debt rating.** Our 2010 capital spending plan was funded mostly from cash flow from operations, which more than doubled from 2009 levels. We applied much of the approximately $3.5 billion proceeds from planned divestitures to reduce debt, which was within target of two times cash flow from operations by year-end. We confirmed our merger-related capital cost savings target of $1 billion per year and increased our operating synergies to $400 million per year, expected to reach $800 million in 2012.

### 2011 – Our targets and how we will get there

- **Achieve annual Oil Sands production of 280,000 – 310,000 barrels per day[4] at a cash operating cost average of $39 to $43 per barrel.** Despite planning to undertake a major turnaround at our Oil Sands operations in 2011, we are targeting an increase of about 5% at the midpoint of guidance over our 2010 production. Completing that maintenance work, coupled with production from Firebag Stage 3 as it ramps up later this year should set us on the path for a strong second half of the year.
- **Establish a solid Exploration and Production division.** We will focus on consolidating non-oil sands upstream exploration and production into one division, which we expect will continue to be a solid source of free cash flow to fund the company's growth plans.
- **Lay a sound foundation for our long-term growth strategy.** We expect to finalize our strategic partnership with Total E&P Canada Ltd., setting favourable conditions that will help us accelerate the development of our growth portfolio and lay a sound foundation for our 2020 growth strategy.
- **Maintain a strong balance sheet.** We expect to finance our 2011 capital spending plan mostly through internal cash flow, proceeds from the agreement with Total E&P Canada Ltd., and other potential asset divestitures. We will also continue to focus on asset optimization as well as project and cash management.
- **Maintain focus on operational excellence.** Continue to drive strategies aimed at improving reliability, personal and process safety, workforce efficiency and engagement, and environmental performance.
- **Continue efforts to reduce environmental impact.** We will pursue the implementation of $TRO_{TM}$ across our existing operations and continue to take a leadership position in collaborative efforts with industry counterparts on the development of environmental technologies. We also expect to complete the expansion of our St. Clair ethanol plant and bring two additional wind power projects on-stream by the end of 2011.

(1) This scorecard should be read in conjunction with Suncor's 2010 Management's Discussion and Analysis and audited Consolidated Financial Statements and the accompanying notes.
(2) Assuming reinvestment of dividends.
(3) The base year for planned improvements is 2007. All the proposed reductions are absolute except for energy efficiency, which is intensity-based.
(4) Excludes our proportionate production share from the Syncrude joint venture.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

February 24, 2011

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2010 audited Consolidated Financial Statements and the accompanying notes.

All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

Additional information about Suncor filed with Canadian securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form dated March 3, 2011 (the 2010 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com.

References to "we," "our," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable consolidated entity on a standalone basis prior to the August 1, 2009 merger date.

## Petro-Canada Merger

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". Amounts disclosed in the audited Consolidated Financial Statements and this MD&A for 2009 and 2010 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures from 2008 reflect solely the results of legacy Suncor. For further information with respect to the merger, please refer to note 3 of the December 31, 2010 audited Consolidated Financial Statements and the accompanying notes.

## Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, namely operating earnings, cash flow from operations, return on capital employed (ROCE), and Oil Sands cash operating costs, are not prescribed by Canadian GAAP. Operating earnings are reconciled to GAAP net earnings in the Consolidated Financial Analysis and Segmented Earnings and Cash Flows sections of this MD&A. Oil Sands cash operating costs are reconciled to GAAP expenses in the Oil Sands – Operating Expenses section of this MD&A. Cash flow from operations and ROCE are defined in the Non-GAAP Financial Measures Advisory section of this MD&A.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included as management uses this information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

## Legal Advisories

This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Legal Advisory – Forward-Looking Information section of this MD&A for information on material risk factors and assumptions underlying our forward-looking information.

Certain crude oil and natural gas liquids (NGL) volumes have been converted to thousands of cubic feet equivalent (mcfe) and millions of cubic feet equivalent (mmcfe) of natural gas on the basis of one barrel (bbl) to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Mmcfe, mcfe, boe and mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

## SUNCOR OVERVIEW

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. Suncor has classified its operations into the following segments:

- **Oil Sands**, includes operations in northeast Alberta to develop and produce synthetic crude through the recovery and upgrading of bitumen from mining and in situ operations. The company has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.
- **Natural Gas**, includes exploration and production of natural gas, crude oil and NGL, primarily in Western Canada.
- **International and Offshore**, includes offshore activity in East Coast Canada, with interests in the Terra Nova, Hibernia, the Hibernia South Extension, White Rose, White Rose Extensions and Hebron oilfields, and exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria.
- **Refining and Marketing**, includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Canada and the U.S., as well as a lubricants plant located in Canada.

In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy assets, including Canada's largest ethanol plant by volume and partnerships in several wind power projects.

### 2010 HIGHLIGHTS

- **Strong financial results.** Net earnings more than tripled to $3.571 billion in 2010 from $1.146 billion in 2009, and our cash flow from operations[(1)] increased to $6.656 billion in 2010, from $2.799 billion in 2009. Our 2010 results reflected the improving economic environment for crude oil and refined products, and solid performance from our assets during the first full year after the August 2009 merger with Petro-Canada. Our return on capital employed[(1)] (excluding major projects in progress) increased to 10.1% in 2010, up from 2.6% in 2009.
- **Ten-year growth strategy.** In December 2010, we announced our new growth strategy. This plan begins in 2011, when we expect to direct approximately $2.8 billion towards a range of growth projects, as part of our overall 2011 capital-spending plan of $6.7 billion.
- **Strategic partnership with Total.** As part of the company's growth strategy, Suncor announced a strategic partnership with Total E&P Canada Ltd. (Total), setting the terms for our two companies to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction of the Voyageur Upgrader. The transaction is subject to certain regulatory and other approvals, with closing targeted late in the first quarter of 2011.
- **Improved operational reliability.** Oil Sands production steadily increased through 2010, finishing the year with record quarterly production volumes of 325,900 barrels per day (excluding Syncrude), compared to 202,300 barrels per day in the first quarter of this year, as a result of improved upgrader performance and strong bitumen supply across all of our Oil Sands assets. Western North America refinery utilization increased through 2010 to 101% in the fourth quarter from 92% in the first quarter.
- **Benefits of integration.** International and Offshore assets acquired in the merger generated strong cash flows, and the increased refining capacity and additional locations in our Refining and Marketing business allowed us to respond to opportunities from both improved margins and logistical constraints in the second half of 2010.
- **Planned divestments.** We successfully completed the planned disposal of approximately $3.5 billion of certain non-core assets from our Natural Gas and International and Offshore businesses. We also reached an agreement to sell non-core U.K. offshore assets, which we expect to complete during the first half of 2011.
- **Balance sheet strength.** Proceeds from our planned divestments have been largely directed to reduce our net debt to $11.1 billion at year-end 2010, from $13.4 billion last year. This, along with our strong financial results, enabled us to improve our key debt ratios, with net debt to cash flow from operations now down to 1.7, from 4.8 last year, well below our target of less than 2.0, and our total debt to total debt plus shareholders' equity measure down to 25%, from 29% in 2009.
- **Tailings pond reclamation.** During the year, Suncor became the first oil sands company to complete surface reclamation of a tailings pond. We also received regulatory approval for a new tailings management plan using the company's proprietary TRO$_{TM}$ tailings management process, which is expected to significantly reduce pond reclamation time.

(1) Cash flow from operations and return on capital employed are non-GAAP measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

## BUSINESS ENVIRONMENT

### Commodity Price Indicators and Exchange Rates

| (average for the year ended December 31) | | 2010 | 2009 | 2008 |
|---|---|---|---|---|
| West Texas Intermediate (WTI) crude oil at Cushing | US$/barrel | **79.55** | 61.80 | 99.65 |
| Dated Brent crude oil at Sullom Voe | US$/barrel | **79.50** | 61.50 | 97.00 |
| Dated Brent/Maya FOB price differential | US$/barrel | **9.30** | 5.00 | 13.15 |
| Canadian 0.3% par crude oil at Edmonton | Cdn$/barrel | **78.05** | 65.80 | 103.05 |
| Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select (WCS) at Hardisty | US$/barrel | **14.20** | 9.70 | 20.10 |
| Natural gas (Alberta spot) at AECO | Cdn$/mcf | **4.15** | 4.15 | 8.15 |
| New York Harbour 3-2-1 crack | US$/barrel | **10.55** | 8.80 | 11.05 |
| Chicago 3-2-1 crack | US$/barrel | **9.00** | 7.75 | 10.40 |
| Seattle 3-2-1 crack | US$/barrel | **13.55** | 11.40 | 12.10 |
| Gulf Coast 3-2-1 crack | US$/barrel | **7.90** | 7.10 | 9.45 |
| Exchange rate | US$/Cdn$ | **0.97** | 0.88 | 0.94 |

Suncor's synthetic crude oil price realization is influenced by the market for light crude and our customers' alternatives. WTI crude oil at Cushing is the most common alternative benchmark. Oil prices strengthened in 2010 with WTI increasing from US$61.80/bbl to US$79.55/bbl since 2009.

Suncor's heavy crude oil price realization is influenced by customers' alternatives. WCS at Hardisty is a common reference price for Canadian heavy crude oil. The light/heavy crude differential between WTI and WCS widened in the second half of the year due to supply and demand factors including the Enbridge pipeline disruptions that limited the export capacity of heavy crude products from Western Canada, resulting in reduced and discounted sales. For the year ended December 31, 2010, this differential represented an average price discount of US$14.20/bbl to WTI, compared to US$9.70/bbl to WTI in 2009.

Suncor's price realization for International and Offshore production is influenced by the widely posted Brent crude oil price marker. Brent crude prices for the year ended December 31, 2010 averaged US$79.50/bbl, up from US$61.50/bbl for the year ended December 31, 2009.

Suncor's natural gas production is primarily referenced to the Alberta spot price at AECO. Natural gas prices for the year ended December 31, 2010 averaged $4.15/mcf, consistent with 2009.

The 3-2-1 crack spreads are industry indicators that roughly approximate the gross refining margin on a barrel of oil for gasoline and distillate. They are calculated by taking two times the spot price of gasoline at a certain location plus one multiplied by the spot price of diesel at the same location, subtracting three times the near-month contract price for NYMEX Light Sweet Crude Oil delivered at Cushing, Oklahoma, and then dividing the entire sum by three. Note that these prices do not necessarily reflect the actual crude purchase costs, product sales realizations, or product configurations of a specific refinery. These crack spreads were all higher for the year ended December 31, 2010 compared to 2009.

The majority of Suncor's revenues from the sale of oil and gas commodities receive prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of commodities and, correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

## Economic Sensitivities

The following table illustrates the estimated effects that changes in certain factors would have had on Suncor's 2010 cash flow from operations and net earnings if they had occurred. Each separate line item in the sensitivity analysis shows the effects of a change in that variable only with all other variables being held constant.

| | Approximate Change in Net Earnings ($ millions) | Approximate Change in Cash Flow from Operations (1) ($ millions) |
|---|---|---|
| **Price** | | |
| Crude oil – WTI US$1.00/bbl | 89 | 114 |
| Natural gas – AECO Cdn$0.10/mcf | 7 | 9 |
| Light/heavy differential – (WTI/WCS) US$1.00/bbl | 34 | 44 |
| **Sales Volume** | | |
| Crude oil – 10,000 bbl/day | 129 | 163 |
| Natural gas – 10 mmcf/d | 1 | 11 |
| **Foreign currency (2)** | | |
| $0.01 change in US$/Cdn$ | (39) | (129) |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The net earnings sensitivity includes the gain or loss on the revaluation of U.S. dollar denominated long-term debt, the change in interest expense on that debt, and the estimated effect on upstream sales realizations and refining margins. The cash flow from operations sensitivity includes the change in interest payments on U.S. dollar denominated long-term debt, and the estimated effect on realizations and margins.

## SELECTED FINANCIAL INFORMATION

### Annual Financial Data

| ($ millions, except as noted) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Revenues (net of royalties)** | | | |
| Continuing operations | **34 350** | 24 848 | 28 446 |
| Discontinued operations (1) | **870** | 632 | 191 |
| | **35 220** | 25 480 | 28 637 |
| **Net earnings (loss)** | | | |
| Continuing operations | **2 688** | 1 206 | 2 082 |
| Discontinued operations | **883** | (60) | 55 |
| | **3 571** | 1 146 | 2 137 |
| **Net earnings from continuing operations per common share** | | | |
| Basic | **1.72** | 1.01 | 2.23 |
| Diluted | **1.71** | 1.00 | 2.20 |
| **Net earnings per common share (2)** | | | |
| Basic | **2.29** | 0.96 | 2.29 |
| Diluted | **2.27** | 0.95 | 2.26 |
| **Cash flow from operations (3)** | | | |
| Continuing operations | **6 164** | 2 434 | 3 888 |
| Discontinued operations | **492** | 365 | 169 |
| | **6 656** | 2 799 | 4 057 |
| **Total assets** | **70 169** | 69 746 | 32 528 |
| **Long-term debt, including current portion** | **12 187** | 13 880 | 7 884 |
| **Dividends on common shares** | **611** | 401 | 180 |
| **Cash dividends per common share** | **0.40** | 0.30 | 0.20 |

(1) Net of $62 million of operating revenues that would be eliminated upon consolidation in the Consolidated Statements of Earnings for the year ended December 31, 2010 (2009 – $33 million, 2008 – $24 million). See note 6 of the audited Consolidated Financial Statements.

(2) Includes continuing and discontinued operations.

(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

## Upstream Production Volumes

| mboe per day (mboe/d) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Continuing operations** | | | |
| Oil Sands | **318.2** | 306.7 | 228.0 |
| Natural Gas | **72.0** | 47.0 | 23.5 |
| International and Offshore | **170.9** | 58.0 | — |
| | **561.1** | 411.7 | 251.5 |
| **Discontinued operations** | | | |
| Natural Gas | **23.8** | 27.4 | 13.2 |
| International and Offshore | **30.2** | 16.9 | — |
| | **54.0** | 44.3 | 13.2 |
| **Total** | **615.1** | 456.0 | 264.7 |

## Downstream Sales Volumes

| Thousands of cubic metres per day (thousands of $m^3$/d) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Total refined product sales** | **87.8** | 54.9 | 31.5 |

## CONSOLIDATED FINANCIAL ANALYSIS

### Net Earnings

Positive factors impacting Suncor's net earnings from continuing operations for 2010, compared to 2009, included:

- Upstream production for 2010 averaged 561,100 boe per day (boe/d), compared to 411,700 boe/d in 2009. Total sales of refined petroleum products averaged 87,800 cubic metres per day ($m^3$/d) during 2010, up from 54,900 $m^3$/d in 2009. Both production and sales volumes increases were primarily due to the additional volumes resulting from the merger.
- Realized prices were higher in 2010 compared to 2009. Increases in benchmark pricing were only partially offset by the widening of heavy crude differentials and the stronger Canadian dollar relative to the U.S. dollar.
- Suncor recognized a pre-tax gain of $295 million pertaining to the redetermination of working interests for the Terra Nova oilfield, after the joint owners reached an agreement on December 1, 2010.

These positive factors were partially offset by the following:

- Operating, selling and general expenses of $7.810 billion were higher in 2010, compared to $6.430 billion in 2009, primarily due to the inclusion of a full twelve months of legacy Petro-Canada operations in 2010, compared to only five months after the merger in 2009, as well as higher planned and unplanned maintenance activities in 2010, compared to 2009.
- Depreciation, depletion and amortization (DD&A) of $3.813 billion was higher in 2010, compared to $1.860 billion in 2009, primarily due to the additional assets acquired through the merger and asset write-downs recorded in 2010.
- Royalties of $1.937 billion were higher in 2010, compared to $1.150 billion in 2009, primarily due to the full year of legacy Petro-Canada production, higher royalty rates, a higher commodity price environment, and receipt of insurance proceeds from Suncor's captive insurance company. These increases were partially offset by a $140 million royalty recovery (pre-tax) booked in the fourth quarter of 2010 related to a notice received by the company from the Alberta government modifying the bitumen valuation methodology (BVM) calculation under Suncor's Royalty Amending Agreement (RAA) that expires in December 2015.
- Financing income was $30 million in 2010, compared to financing income of $488 million in 2009, largely due to lower foreign exchange gains on U.S. dollar denominated long-term debt in 2010.
- In 2009, net earnings included a pre-tax gain of $438 million on the effective settlement of a pre-existing processing contract with Petro-Canada, whereby Suncor processed MacKay River bitumen production for a fee.

Income tax expense was $1.860 billion in 2010 (34% effective tax rate), compared to $143 million in 2009 (11% effective tax rate). The lower effective tax rate in 2009 was primarily due to the lower tax rate applicable to the company's foreign exchange gains on U.S. dollar denominated long-term debt, and no tax impact on the gain on effective settlement of the pre-existing processing contract with Petro-Canada.

## Discontinued operations

In 2010, Suncor divested a number of non-core assets in the Natural Gas and International and Offshore segments. Results up to the closing date and any associated gain or loss on disposals of assets are presented as discontinued operations, as determined in accordance with GAAP. Current year net earnings from discontinued operations of $883 million includes pre-tax gains of $814 million on the asset disposals.

## Cash flow from operations

Cash flow from operations was $6.656 billion in 2010, compared to $2.799 billion in 2009. The increase in cash flow from operations was primarily due to increased production volumes, higher refining and marketing sales, and higher realized prices. Cash flow from operations is a non-GAAP measure that the company uses to measure performance. See the Non-GAAP Financial Measures Advisory section of this MD&A.

## Net Earnings for 2009 compared with 2008

Net earnings from continuing operations were $1.206 billion in 2009, compared with $2.082 billion in 2008. The decrease in net earnings from continuing operations was due primarily to lower price realizations, as well as costs related to deferring growth projects, and merger and integration costs associated with the merger with Petro-Canada on August 1, 2009. These impacts more than offset the increased upstream production, increased refined product sales volumes, and the gain on the effective settlement of a pre-existing processing contract with Petro-Canada. Net earnings in 2009 also included losses on commodity derivatives used for risk management, compared to a gain on these derivatives in 2008.

The merger increased Suncor's asset base by $35.8 billion, including goodwill, and long-term debt by $4.4 billion.

## Operating Earnings[1]

| Year ended December 31 ($ millions after-tax) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Net earnings from continuing operations** | **2 688** | 1 206 | 2 082 |
| Change in fair value of commodity derivatives used for risk management, net of realizations[2] | **(233)** | 499 | (372) |
| Unrealized foreign exchange gain on U.S. dollar denominated long-term debt | **(372)** | (798) | 852 |
| Mark-to-market valuation of stock-based compensation | **103** | 124 | (107) |
| Project start-up costs | **58** | 40 | 24 |
| Costs related to deferral of growth projects | **94** | 300 | — |
| Merger and integration costs | **79** | 151 | — |
| (Gain)/Loss on disposals[3] | **(121)** | 39 | — |
| Other income[4] | **(166)** | 24 | — |
| Adjustments to provisions[5] | **(51)** | 50 | — |
| Impairment and write-offs[6] | **317** | — | — |
| Adjustments to provisions for assets acquired through the merger[7] | **68** | — | — |
| Gain on effective settlement of pre-existing contract with Petro-Canada[8] | **—** | (438) | — |
| Impact of recording acquired inventory at fair value[9] | **—** | 97 | — |
| Impact of income tax rate adjustments on future income tax liabilities[10] | **—** | 4 | — |
| **Operating earnings from continuing operations** | **2 464** | 1 298 | 2 479 |
| **Net earnings (loss) from discontinued operations** | **883** | (60) | 55 |
| Gain on disposals of discontinued operations[3] | **(689)** | — | — |
| Impairment and write-offs of discontinued operations[6] | **74** | 42 | — |
| **Operating earnings from total operations** | **2 732** | 1 280 | 2 534 |

(1) Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that management believes are not indicative of operating performance and reduces the comparability of the underlying financial performance between periods. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The company adjusts operating earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives in other segments that are not adjusted.

(3) The 2010 total includes Natural Gas non-core asset sales and International and Offshore asset and share sales, a gain on unproven land in Natural Gas, and gains on Refining and Marketing sale of retail sites. The 2009 total related to a loss recognized when a highway interchange constructed by Suncor was transferred to the Government of Alberta, and fair value adjustments to assets acquired in the merger.

(4) Other income resulting from the settlement payment due to Suncor related to the Terra Nova redetermination. The payment will effectively reimburse Suncor for certain revenue related to its increased working interest (to 37.675% from 33.990%) back to the payout date of February 1, 2005. Operating earnings for 2010 and 2009 have been restated to reflect the portion of settlement attributable to the respective year.

(5) Impact from a royalty recovery related to a notice received by the company from the Alberta government modifying the BVM calculation for the interim period January 1, 2009 to December 31, 2010. As a result, the company reduced its royalty expense reserve by approximately $105 million (after-tax) in the fourth quarter of 2010. Operating earnings for prior years have been restated to effectively remove the original

provision booked. The company continues to negotiate final adjustments to the BVM calculation for the 2009 and 2010 interim period and for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015.

(6) The 2010 total includes a write-down related to certain extraction equipment in the Oil Sands segment, a write-down of land leases no longer being pursued by the Natural Gas segment, an impairment of natural gas properties due to the lower gas price environment, an adjustment to spare parts inventory and an impairment of assets from the International and Offshore segment based on agreed sale price.

(7) The 2010 total includes adjustments for unfavourable pipeline commitments, adjustments made for past cost reconciliation related to the Exploration and Production Sharing Contracts (EPSAs) in Libya, a dry hole in Libya, a write-off of unproven land in Natural Gas, and a reduction to the provision related to the Montreal coker project.

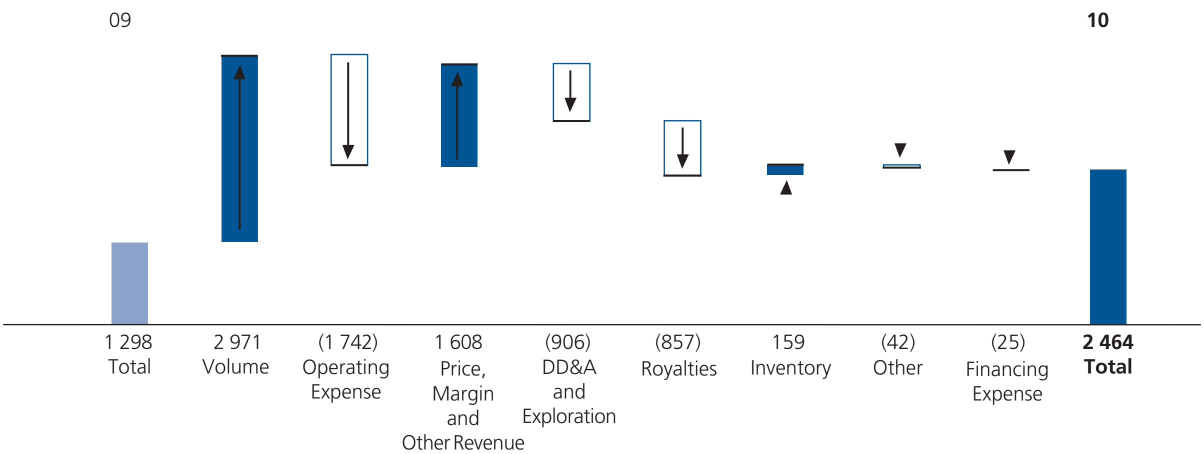
(8) Impact from the deemed settlement value assigned to the bitumen processing contract with Petro-Canada upon close of the merger.

(9) Inventory acquired through the merger with Petro-Canada at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact on earnings.

(10) Net impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger and a decrease in the future income tax liability resulting from the provincial rate reduction in Ontario.

## Consolidated Operating Earnings from Continuing Operations

($ millions)




## Operating Earnings by Segment

| Year ended December 31 ($ millions after-tax) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Continuing operations** | | | |
| Oil Sands | **1 535** | 1 116 | 2 522 |
| Natural Gas | **(137)** | (173) | 34 |
| International and Offshore | **993** | 362 | — |
| Refining and Marketing | **782** | 473 | (23) |
| Corporate, Energy Trading and Eliminations | **(709)** | (480) | (54) |
| | **2 464** | 1 298 | 2 479 |
| **Discontinued operations** | | | |
| Natural Gas | **49** | (14) | 55 |
| International and Offshore | **219** | (4) | — |
| | **268** | (18) | 55 |
| **Total operating earnings** [(1)] | **2 732** | 1 280 | 2 534 |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

## SEGMENTED EARNINGS AND CASH FLOWS

### Oil Sands

Located in northeast Alberta, the Oil Sands operations recover bitumen from mining and in situ operations (Firebag and MacKay River) and upgrade the majority of this production into refinery feedstock, diesel fuel and byproducts. The company's marketing plan also includes sales of bitumen when market conditions are favourable or when operating conditions warrant. The Oil Sands business also includes a 12% ownership interest in the Syncrude oil sands joint venture and a share in the Fort Hills project.

On December 17, 2010, Suncor announced a strategic partnership with Total. Subject to certain conditions, the agreement provides that the two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction on the Voyageur Upgrader, all with targeted operational dates ranging from 2016 to 2018.

On closing, it is expected that Total will acquire a 49% interest in Suncor's Voyageur Upgrader, and an additional 19.2% in the Fort Hills project, reducing Suncor's interest from 60% to 40.8%. In return, it is expected that Suncor will acquire a 36.75% interest in the Joslyn project and receive cash consideration of approximately $1.75 billion.

The transaction is subject to certain regulatory and other approvals, with closing targeted during the first quarter of 2011. The development of the Fort Hills and Joslyn oil sands mining projects, as well as the continued construction of the Voyageur Upgrader, is subject to approval by all of the partners in these ventures and by Suncor's Board of Directors.

| Year ended December 31<br>($ millions, unless otherwise noted) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Gross revenues and other income | **10 104** | 7 184 | 9 354 |
| Less: Royalties | **(681)** | (645) | (715) |
| Net revenues | **9 423** | 6 539 | 8 639 |
| Total production in thousands of barrels per day (mbbls/d) | **318.2** | 306.7 | 228.0 |
| Average sales price – includes the impact of realized risk management activities (excluding Syncrude) ($/bbl) (1) | **69.58** | 61.66 | 95.96 |
| Net earnings | **1 492** | 557 | 2 875 |
| Operating earnings (2) | **1 535** | 1 116 | 2 522 |
| Cash flow from operations (2) | **2 769** | 1 251 | 3 507 |
| Cash operating costs (excluding Syncrude) ($/bbl) (2) | **38.85** | 33.95 | 38.50 |
| Sales mix (sweet/sour mix) (%) | **37/63** | 47/53 | 43/57 |

(1) Before royalties and net of related transportation costs.

(2) Non-GAAP measures. Operating earnings and cash operating costs are reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

### Operating Earnings Reconciliation

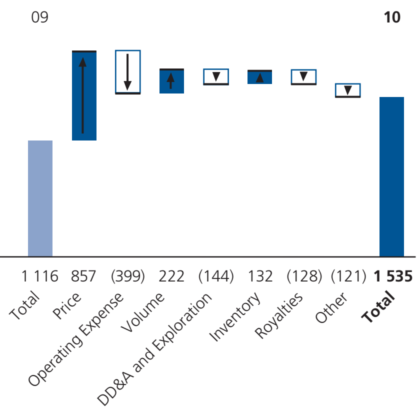
| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Net earnings** | **1 492** | 557 | 2 875 |
| Change in fair value of commodity derivatives used for risk management, net of settlements | **(233)** | 499 | (372) |
| Mark-to-market valuation of stock-based compensation | **31** | 28 | (5) |
| Project start-up costs | **55** | 40 | 24 |
| Costs related to deferral of growth projects | **94** | 299 | — |
| Losses on disposals | **4** | 39 | — |
| Impairment and write-offs | **143** | — | — |
| Adjustment to provisions | **(51)** | 50 | — |
| Impact of income tax rate adjustments on future income tax liabilities | **—** | 37 | — |
| Gain on effective settlement of pre-existing contract with Petro-Canada | **—** | (438) | — |
| Impact of recording acquired inventory at fair value | **—** | 5 | — |
| **Operating earnings** (1) | **1 535** | 1 116 | 2 522 |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands net earnings were $1.492 billion in 2010, compared to $557 million in 2009. Net earnings in 2010 included the impacts of higher average prices for oil sands crude products, a gain on commodity derivatives used for risk management, compared to a loss in 2009, increased total production and lower costs related to deferral of growth projects. Net earnings in 2010 also included a $140 million (pre-tax) royalty provision recovery related to a notice received by the company from the Alberta Government modifying the BVM calculation for the interim period January 1, 2009 to December 31, 2010, under Suncor's RAA. These factors were partially offset by higher 2010 operating costs, including higher project start-up costs for Firebag Stages 3 and 4, a write-down of certain extraction assets that were being developed as an alternative extraction process to crush and slurry oil sands at the mine face and a gain on the effective settlement of a pre-existing contract with Petro-Canada in 2009, whereby Suncor processed MacKay River bitumen production for a fee.

## Continuing Operations

**Operating Earnings from Continuing Operations**
($ millions)




Operating earnings for 2010 were $1.535 billion, compared to $1.116 billion in 2009. The 38% increase in 2010 operating earnings was primarily due to higher realized prices and increased total production, partially offset by higher operating expenses.

## Production Volumes

| Year ended December 31 (mbbls/d) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Production excluding Syncrude | **283.0** | 290.6 | 228.0 |
| Syncrude production [1] | **35.2** | 16.1 | — |
| Total production | **318.2** | 306.7 | 228.0 |

(1) Production for the five months ended December 31, 2009 was 38.5 mbbls/d.

Total production increased 4% in 2010, compared to 2009, primarily due to additional production from Syncrude as a result of the timing of the merger. Apart from the Syncrude production, the merger did not result in increased Oil Sands production volumes, as production from MacKay River was included in Suncor's reported production during 2009 as volumes processed by Suncor under a processing fee agreement. However, the addition of seven months of MacKay River production in 2010 due to the timing of the merger has resulted in increased sales volumes for Oil Sands, as volumes under the processing agreement with Petro-Canada were not included in sales prior to August 1, 2009.

Production of 283,000 bpd in 2010, excluding Syncrude, was 3% lower compared with 290,600 bpd in 2009. The beginning of 2010 was negatively impacted by both planned and unplanned maintenance, which was partially offset by improved upgrader reliability and bitumen supply in the latter part of the year. Oil Sands completed the year with record production of 325,900 bpd in the fourth quarter of 2010. Unplanned maintenance at the beginning of the year included rebuild work on Upgrader 2 and Upgrader 1 following fires in December 2009 and February 2010. As a result, production for the year was reduced by approximately 29,500 bpd. The production impacts of the fire were mitigated by Suncor's ability to sell bitumen in the market, avoiding a shut-in of production.

Syncrude production contributed 35,200 bpd of sweet synthetic crude production in 2010, compared to 16,100 bpd in 2009. The increase was due to the additional seven months of production included in 2010, compared to 2009, as a result of the timing of the merger. Excluding the effects related to the timing of the merger, production from Syncrude decreased 9% due to planned and unplanned upgrader maintenance.

### Prices

| Year ended December 31 (in Cdn$ per bbl) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Average sales price – includes the impact of realized risk management activities (excluding Syncrude) | **69.58** | 61.66 | 95.96 |
| Average sales price – Syncrude | **80.93** | 77.36 | — |
| Sales mix (sweet/sour mix) (%) | **37/63** | 47/53 | 43/57 |
| Sales volumes (mbbls/d) – excluding Syncrude | **279.3** | 276.2 | 227.0 |
| Syncrude sales volumes (mbbl/d) | **35.2** | 16.1 | — |

Oil Sands benefited from higher benchmark crude oil prices and lower realized losses in 2010 compared to 2009, partially offset by wider heavy crude differentials, change in sales mix and the stronger Canadian dollar relative to the U.S. dollar. Heavy crude oil differentials widened in the second half of 2010, as a result of the Enbridge pipeline disruptions that limited the export capacity of heavy crude products from Western Canada, resulting in reduced and discounted sales. These disruptions, and the resulting increase in supply of heavy crude products, negatively impacted both sour crude and bitumen price realizations.

Sales mix was negatively impacted in 2010 by the upgrader fires that occurred in December 2009 and February 2010, and by hydrogen supply and hydrotreating capacity issues in the latter part of 2010. This resulted in a lower percentage of higher value sweet crude product produced, increasing the sales volumes of lower value sour crude and bitumen.

In 2010, the Suncor average price realization on the crude sales basket, excluding Syncrude and derivatives used for risk management, was WTI less US$9.92 per bbl, or 88% of WTI, in comparison to 2009 when the price realization was WTI less US$5.22 per bbl, or 92% of WTI.

### Operating Expenses

Operating expenses were higher in 2010, compared to 2009, primarily due to the inclusion of a full year of operating costs from the company's proportionate share of the Syncrude joint venture, higher costs from planned and unplanned maintenance, and the full year of operating costs from MacKay River operations, due to the timing of the merger. As noted previously in this MD&A, MacKay River production volumes were included in the 2009 results, whereas the associated operating expenses were not included as the volumes had originally been recorded under a processing agreement.

Third-party crude and diesel product purchases were higher in 2010, compared to 2009, to facilitate placement of Oil Sands heavy production and to fulfill contractual obligations. Product purchases have a minimal effect on earnings as these are largely offset in revenue.

### Cash Operating Costs Reconciliation (1)(2)

| Year ended December 31 | **2010** | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| ($ millions, unless otherwise noted) | **$ millions** | **$/bbl** | $ millions | $/bbl | $ millions | $/bbl |
| Operating, selling and general expenses | **4 545** | | 4 277 | | 3 203 | |
| Adjustments: | | | | | | |
| Syncrude-related operating, selling and general expenses | **(473)** | | (199) | | — | |
| Other non-production related costs (3) | **(60)** | | (479) | | 9 | |
| Cash operating costs – excluding Syncrude | **4 012** | **38.85** | 3 599 | 33.95 | 3 212 | 38.50 |

(1) Excludes Suncor's proportionate production share and operating costs from the Syncrude joint venture.

(2) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Other adjustments includes items such as safe mode costs (the cost of placing a growth project on hold or in "safe mode"), inventory changes, stock-based compensation, gas swaps, accretion of asset retirement obligations and imported bitumen (excluding other reported product purchases). For the twelve months ended December 31, other non-production related costs were lower in 2010 compared to 2009, primarily due to lower safe mode costs ($254 million) offset by higher imported bitumen costs ($67 million).

Cash operating costs (excluding Syncrude) increased to $4.012 billion in 2010 from $3.599 billion in 2009. On a per barrel basis, these costs increased to $38.85/bbl in 2010 compared to $33.95/bbl in 2009, an increase of 14% year-over-year. The increase in cash operating costs was primarily due to the additional seven months of operating costs from the MacKay River operation, and reduced volumes and higher costs from planned and unplanned maintenance.

Cash operating costs for Suncor's interest in Syncrude operations averaged $37.95 per bbl in 2010, compared to $32.50 per bbl for the last five months of 2009. The increase in the current year was primarily due to the effects of planned maintenance on 2010 production, compared to 2009, where the five-month period included in 2009 due to the timing of the merger excluded significant effects of planned and unplanned maintenance.

Users are cautioned that the cash operating costs per barrel measure is not directly comparable to similar information calculated by other entities (including Syncrude), due to different accounting treatments for operating and capital costs amongst producers.

### DD&A

The increase in DD&A expense from 2010 was due to newly commissioned assets and additional depreciation due to the assets acquired during the merger. Oil Sands assets are primarily depreciated on a straight-line basis.

### Royalties

The increase in royalty expense was primarily due to the inclusion of a full twelve months of royalty payable production acquired in the merger (versus only five months in 2009) related to MacKay River and Suncor's proportionate share of Syncrude production, higher royalty rates and receipt of insurance proceeds from Suncor's captive insurance company for which royalties were payable. Suncor's MacKay River project moved to post-payout in November 2010, thereby increasing the percentage of royalties paid to approximately 31% of revenues minus costs for this period. Suncor's Firebag operation continued in the pre-payout phase and royalties were calculated at the minimum royalty percentage of revenues, which was a rate based on the Canadian dollar equivalent of WTI up to a maximum of 9%.

### Safe Mode Costs

The company continues to incur costs related to placing certain growth projects into "safe mode" due to unfavourable market conditions in prior years. Safe mode costs are defined as the costs of deferring the projects, maintaining the equipment and facilities in a safe manner in order to expedite remobilization and the actual remobilization cost of growth projects placed into safe mode. As a result of placing certain projects into safe mode, pre-tax costs of $126 million were incurred in 2010, compared to $380 million in 2009. In 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all remobilized.

### Planned Maintenance Turnarounds

Suncor's Oil Sands business has a six-week planned turnaround scheduled for Upgrader 2 in the second quarter of 2011. Production volumes are expected to be reduced by approximately 215,000 bpd over the duration of the turnaround.

## Natural Gas

Suncor's Natural Gas business, operating primarily in Western Canada, explores for, acquires, develops and produces natural gas, NGLs, oil and byproducts that are used for internal consumption and sale to customers across North America.

| Year ended December 31 ($ millions, unless otherwise noted) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Gross revenues from continuing operations | **810** | 459 | 471 |
| Less: Royalties from continuing operations | **(76)** | (36) | (107) |
| Net revenues from continuing operations | **734** | 423 | 364 |
| Gross production | | | |
| Continuing operations (mmcfe per day – mmcfe/d) | **432** | 282 | 141 |
| Discontinued operations (mmcfe/d) | **143** | 164 | 79 |
| | **575** | 446 | 220 |
| Average sales price from continuing operations | | | |
| Natural gas – includes the impacts of realized risk management activities ($/mcf) (1) | **3.99** | 3.63 | 8.21 |
| Natural gas liquids and crude oil ($/bbl) (1) | **77.37** | 59.41 | 68.05 |
| Net earnings (loss) | | | |
| Continuing operations | **(277)** | (185) | 34 |
| Discontinued operations | **506** | (14) | 55 |
| | **229** | (199) | 89 |
| Operating earnings (loss) (2) | | | |
| Continuing operations | **(137)** | (173) | 34 |
| Discontinued operations | **49** | (14) | 55 |
| | **(88)** | (187) | 89 |
| Cash flow from operations (2) | | | |
| Continuing operations | **320** | 177 | 198 |
| Discontinued operations | **125** | 152 | 169 |
| | **445** | 329 | 367 |

(1) Calculated before royalties and net of transportation costs.

(2) Non-GAAP measures. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

## Operating Earnings Reconciliation

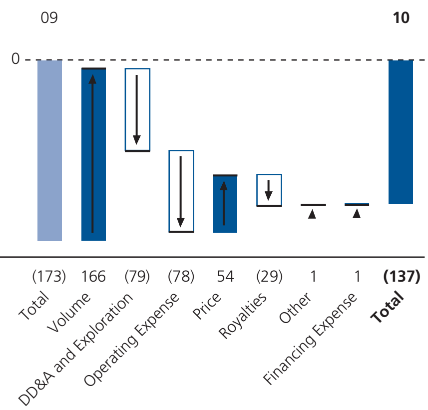
| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Net loss from continuing operations** | **(277)** | (185) | 34 |
| Mark-to-market valuation of stock-based compensation | **9** | 11 | — |
| Gains on disposals | **(99)** | — | — |
| Impact of income tax rate adjustments on future income tax liabilities | **—** | 1 | — |
| Impairment and write-offs | **174** | — | — |
| Adjustments to provisions for assets acquired through the merger | **56** | — | — |
| **Operating loss from continuing operations** (1) | **(137)** | (173) | 34 |
| **Net earnings (loss) from discontinued operations** | **506** | (14) | 55 |
| Gains on disposals of discontinued operations | **(479)** | — | — |
| Impairment and write-offs | **22** | — | — |
| **Operating loss from total operations** (1) | **(88)** | (187) | 89 |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Natural Gas had total net earnings of $229 million in 2010, compared with a net loss of $199 million in 2009. Net earnings in 2010 were positively impacted, compared to 2009, by pre-tax gains of $774 million on asset dispositions for non-core assets and unproven land sold in 2010, and increased total production as a result of the merger. These factors were partially offset by a $222 million write-down (pre-tax) of certain assets where the carrying value of the assets was greater than their expected discounted future cash flows, and the $44 million write-down (pre-tax) of certain land leases in Western Canada and Alaska that the company was no longer pursuing as part of its strategic business realignment.

## Continuing Operations

**Operating Loss from Continuing Operations**
($ millions)




Operating loss from continuing operations in 2010 was $137 million, compared to an operating loss from continuing operations of $173 million in 2009. The decrease in operating loss from continuing operations in 2010 was primarily due to higher production volumes as a result of the merger, lower exploration expenses and higher realized prices. This was partially offset by higher lifting costs as a result of the merger and higher DD&A expense.

## Production Volumes

| Year ended December 31 (mmcfe/d) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Natural gas | **399** | 262 | 135 |
| Natural gas liquids and crude oil | **33** | 20 | 6 |
| Gross production | **432** | 282 | 141 |

Gross production from continuing operations increased 53% in 2010, compared to 2009. The increase primarily reflects additional production associated with the assets acquired as a result of the merger, partially offset by asset dispositions and natural declines.

## Prices

Natural gas average realized prices were higher in 2010, compared to 2009, although the average AECO benchmark was unchanged year-over-year, due to the volume and timing of sales in 2009. As a result of the merger, sales were higher in the second half of 2009 when the AECO benchmark price was lower, which had an overall impact of decreasing the natural gas realized price in 2009. In 2010, sales volumes and realized prices were more consistent throughout the year and transportation costs were lower.

## Operating Expenses

Operating expenses from continuing operations increased in 2010, compared to 2009, due to the operating expenses associated with the assets acquired as a result of the merger being included for the full 2010 year, compared to only five months in 2009, due to the timing of the merger. Operating expenses per unit of production of $2.18/mcfe were higher than 2009 ($1.98/mcfe), primarily due to plant turnaround costs incurred in the fourth quarter of 2010.

## DD&A and Exploration Expenses

DD&A from continuing operations increased in 2010, compared to 2009, primarily due to higher production volumes from assets acquired as a result of the merger. Natural Gas assets are primarily depleted on a unit-of-production basis.

Exploration expenses from continuing operations decreased due to reduced exploration activity and increased drilling success in 2010, resulting in lower dry hole costs.

## Royalties

In 2010, total Crown royalties from continuing operations increased compared to 2009. The increased royalties were primarily associated with the production acquired as a result of the merger, higher realized prices in 2010 versus 2009 and higher royalty credits received in 2009.

## Discontinued Operations

Natural Gas has divested a number of non-core natural gas assets throughout 2010. Discontinued operations as determined in accordance with GAAP includes the results, up to the closing date, of assets that have been sold during the year. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during 2010. The following is a summary of key divestitures:

- On March 1, 2010, the company completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.
- On March 31, 2010, the company completed the sale of certain non-core natural gas properties located in northeast British Columbia, known as Blueberry and Jedney, for net proceeds of $383 million.
- On May 31, 2010, the company completed the sale of non-core natural gas properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.
- On August 31, 2010, the company completed the sale of its non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinius, for net proceeds of $275 million.
- On September 30, 2010, the company completed the sale of its non-core natural gas properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.

## International and Offshore

Suncor's International and Offshore operations comprise production and exploration activity offshore Newfoundland and in the North Sea, onshore production and exploration activity in Libya and Syria, and exploration acreage in Norway.

In East Coast Canada, Suncor operates Terra Nova, holding a working interest of 37.675% that increased from 33.990% effective January 1, 2011. This working interest redetermination was finalized in December 2010 in accordance with the Terra Nova Development and Operating Agreement. Suncor also holds a 20% interest in Hibernia and a 19.5% interest in the Hibernia South Extension, a 27.5% interest in White Rose and a 26.125% interest in White Rose North Amethyst and West White Rose Extension, and a 22.7% interest in Hebron. In the North Sea, Suncor holds a 29.9% working interest in Buzzard. Suncor also operates in Libya, pursuant to EPSAs, to design and implement jointly the development of oil fields in the Sirte Basin, and in Syria, pursuant to a production sharing contract (PSC), on the Ebla gas project to develop the Ash Shaer and Cherrife areas.

In late February, civil unrest swept Libya. At the time of filing this report, the degree and duration of impact on Suncor's operations is not known.

| Year ended December 31 ($ millions, unless otherwise noted) | **2010** | 2009 |
|---|---|---|
| Gross revenues from continuing operations | **5 503** | 1 686 |
| Less: Royalties | **(1 180)** | (469) |
| Net revenues from continuing operations | **4 323** | 1 217 |
| Production from continuing operations (mboe/d) | | |
| East Coast Canada | **68.6** | 24.3 |
| U.K. (Buzzard) | **55.5** | 20.0 |
| Libya | **35.2** | 13.7 |
| Syria | **11.6** | — |
| Total production from continuing operations (mboe/d) | **170.9** | 58.0 |
| Total production from discontinued operations (mboe/d) | **30.2** | 16.9 |
| Total production (mboe/d) (1) | **201.1** | 74.9 |
| Average sales price from continuing operations (2) | | |
| East Coast Canada ($/bbl) | **80.20** | 76.86 |
| U.K. (Buzzard) ($/boe) | **77.91** | 69.53 |
| Other International ($/boe) | **78.07** | 77.53 |
| Net earnings (loss) | | |
| Continuing operations | **1 114** | 323 |
| Discontinued operations | **377** | (46) |
| | **1 491** | 277 |
| Operating earnings (loss) (3) | | |
| Continuing operations | **993** | 362 |
| Discontinued operations | **219** | (4) |
| | **1 212** | 358 |
| Cash flow from operations (3) | | |
| Continuing operations | **2 512** | 738 |
| Discontinued operations | **367** | 213 |
| | **2 879** | 951 |

(1) Production for the five months ended December 31, 2009 was 178.8 mboe/d.

(2) Calculated before royalties and net of transportation costs.

(3) Non-GAAP measure. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of the MD&A.

## Operating Earnings Reconciliation

| Year ended December 31 ($ millions) | 2010 | 2009 |
|---|---|---|
| **Net earnings from continuing operations** | **1 114** | 323 |
| Mark-to-market valuation of stock-based compensation | **14** | 10 |
| Other income (1) | **(166)** | 24 |
| Project start-up costs | **3** | — |
| Impact of income tax rate adjustments on future income tax liabilities | **—** | (20) |
| Impact of recording acquired inventory at fair value | **—** | 25 |
| Adjustments to provisions for assets acquired through the merger | **28** | — |
| **Operating earnings from continuing operations (2)** | **993** | 362 |
| **Net earnings (loss) from discontinued operations** | **377** | (46) |
| Gains on disposals of discontinued operations | **(210)** | — |
| Impairment and write-offs | **52** | 42 |
| **Operating earnings from total operations (2)** | **1 212** | 358 |

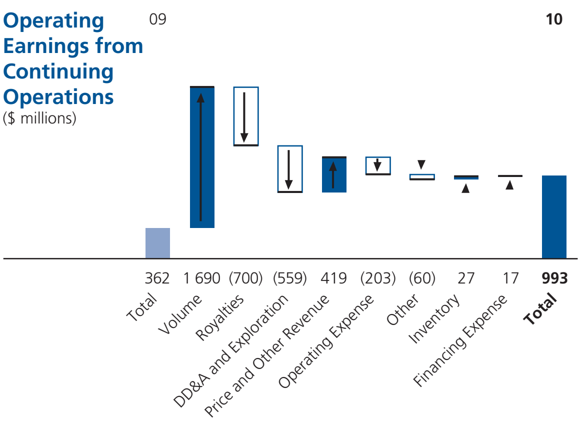
(1) Other income resulting from the settlement payment due to Suncor related to the Terra Nova redetermination. The payment of $220 million (after-tax) reimburses Suncor for certain net revenues related to its increased interest from the field payout date of February 1, 2005 to December 31, 2010. Operating earnings for 2010 and 2009 have been restated to include only the amount that relates to the comparative period.

(2) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of the MD&A.

International and Offshore had net earnings of $1.491 billion in 2010, compared to $277 million in 2009. Net earnings in 2010 were positively impacted by increased production as a result of the timing of the merger and new production coming on-stream in 2010, higher realized commodity prices, pre-tax gains of $170 million on asset dispositions and the $295 million pre-tax gain recognized pertaining to the Terra Nova redetermination.

### Continuing Operations

**Operating Earnings from Continuing Operations**
($ millions)




Operating earnings from continuing operations were $993 million in 2010, compared to $362 million in 2009. Operating earnings from continuing operations were higher in 2010 due to increased production as a result of the timing of the merger and new production coming on-stream, and higher realized commodity prices. These increases were partially offset by increases to royalty expense and DD&A expense, due to the additional seven months of operations as a result of the timing of the merger.

### Production Volumes

| Year ended December 31 (mboe/d) | 2010 | 2009 |
|---|---|---|
| Production from continuing operations | | |
| East Coast Canada | | |
| Terra Nova | **23.2** | 8.7 |
| Hibernia | **30.9** | 11.4 |
| White Rose | **14.5** | 4.2 |
| U.K. | | |
| Buzzard | **55.5** | 20.0 |
| Libya | **35.2** | 13.7 |
| Syria | **11.6** | — |
| Total production (1) | **170.9** | 58.0 |

(1) Production from continuing operations for the five months ended December 31, 2009 averaged 138.4 mboe/d.

Production from continuing operations was significantly higher in 2010, compared to 2009, primarily due to the seven additional months of production included in 2010 as a result of the timing of the merger. Excluding the volume impacts due to the merger, there was higher production in 2010, compared with 2009, as a result of new production that came on-stream in 2010 in Syria and the North Amethyst portion of the White Rose Extensions (North Amethyst), and from new production from the AA Block area of Hibernia that came on-stream at the end of 2009. Buzzard also had higher production in 2010 due to the smaller scope of maintenance activity as compared to 2009.

## Prices

International and Offshore benefited from higher price realizations in 2010, due to higher benchmark commodity prices relative to 2009.

## Operating Expenses

Operating expenses from continuing operations increased in 2010, compared to 2009, primarily due to the additional seven months of production included in 2010 as a result of the timing of the merger, and costs associated with the new production delivered from Syria and North Amethyst, partially offset by cost reduction initiatives undertaken during the year.

## DD&A

DD&A from continuing operations was higher in 2010, compared to 2009. The increase was primarily due to higher production from the additional seven months of production included as a result of the timing of the merger and new production coming on-stream in 2010.

## Royalties

Royalties were higher in 2010, compared to 2009, primarily due to the additional seven months of production included in 2010 as a result of the timing of the merger, additional production coming on-stream in 2010 and higher realized prices, partially offset by increases in capital and operating expenditures for East Coast Canada operations.

Royalties are not paid on U.K. production. Suncor's operations in Libya and Syria are conducted pursuant to PSCs. The royalty amounts presented reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the applicable contract. All government interests in the operations, except for income taxes, are presented as royalties.

## Planned Maintenance Turnarounds

At Terra Nova, a 15-week dockside maintenance program is planned in 2011. Production volumes are expected to be reduced by approximately 25,000 bpd over the duration of the turnaround. However, Suncor is working with partners to consider the possibility of delaying this to 2012.

Also in 2011, White Rose has a three-week routine turnaround planned and Buzzard has a one-week shutdown planned.

## Discontinued Operations

International and Offshore substantially completed its strategic divestment activities and has divested a number of assets throughout 2010. Discontinued operations, determined in accordance with GAAP, include the results, up to the closing date, of assets that have been sold during the quarter, as well as results from certain assets the company expects to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the third quarter of 2010.

- On August 5, 2010, the company completed the sale of its assets in Trinidad and Tobago, for net proceeds of US$378 million with an effective date of January 1, 2010.
- On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands B.V., for net proceeds of €316 million with an effective date of January 1, 2010.
- On September 8, 2010, the company reached an agreement to sell its non-core U.K. offshore assets (Scott/Telford and Triton) for gross proceeds of £240 million, effective July 1, 2010. The sale involves interests in 12 offshore production and exploration licences in the U.K. sector of the North Sea. Divestment of a portion of those assets was completed in 2010 for net proceeds of £55 million. The sales of the remaining assets are expected to close during the first half of 2011. The remaining divestments are subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.

## Refining and Marketing

Refining and Marketing refines crude oil into a broad range of petroleum and petrochemical products at refineries located in Edmonton, Montreal and Sarnia in Canada, and Commerce City, Colorado in the U.S. Products are sold to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and joint venture-operated retail stations in Canada and Colorado, a nationwide Canadian commercial road transport network and a bulk sales channel. Refining and Marketing also owns and operates a lubricants business located in Mississauga, Ontario that manufactures, blends and markets high quality products worldwide. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the United States.

| Year ended December 31 ($ millions, unless otherwise noted) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Revenues | **21 062** | 11 851 | 9 258 |
| Refined product sales (thousands of $m^3$/d) | | | |
| Gasoline | **41.1** | 27.6 | 15.9 |
| Distillates | **30.9** | 18.3 | 10.8 |
| Other, including petrochemicals | **15.8** | 9.0 | 4.8 |
| Total refined product sales (1) | **87.8** | 54.9 | 31.5 |
| Crude oil processed by Suncor (thousands of $m^3$/d) (2) | **65.1** | 42.2 | 24.7 |
| Net earnings (loss) | **801** | 407 | (22) |
| Operating earnings (3) | | | |
| Refining and product supply | **523** | 321 | (60) |
| Marketing | **259** | 152 | 37 |
| Total operating earnings (loss) | **782** | 473 | (23) |
| Cash flow from operations (3) | **1 536** | 921 | 220 |

(1) Total refined product sales for the five months ended December 31, 2009 was 84.8 thousands of $m^3$/d.

(2) Crude oil processed by Suncor for the five-month period ended December 31, 2009 was 63.5 thousands of $m^3$/d.

(3) Non-GAAP measure. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

## Operating Earnings Reconciliation

| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Net earnings (loss)** | **801** | 407 | (22) |
| Mark-to-market valuation of stock-based compensation | **29** | 17 | (1) |
| Gains on disposals | **(26)** | — | — |
| Adjustments to provisions for assets acquired through the merger | **(22)** | — | — |
| Impact of income tax rate reductions on opening future income tax liabilities | **—** | (19) | — |
| Impact of recording acquired inventory at fair value | **—** | 67 | — |
| Costs related to deferral of growth projects | **—** | 1 | — |
| **Operating earnings (1)** | **782** | 473 | (23) |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

The Refining and Marketing business recorded net earnings of $801 million in 2010 compared with $407 million in 2009. The higher net earnings in 2010 relative to 2009 were primarily due to additional refining capacity gained through the merger, favourable margins and a $67 million negative fair value adjustment (after-tax) included in 2009 net earnings related to the acquisition of inventory as part of the merger. These items were partially offset by higher operating expenses and DD&A. Operating earnings in 2010 were $782 million, which was a $309 million increase over 2009 primarily due to increased volumes from the seven additional months of merged operations in 2010 and improved refining margins, partially offset by higher operating expenses.

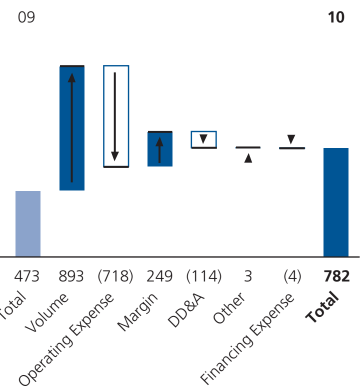
Refining and product supply activities contributed operating earnings of $523 million in 2010, up from $321 million in 2009. The increase was due to improved operational reliability and increased production gained from the addition of the Edmonton refinery, Montreal refinery, and the lubricants plant, as a result of the merger. The 2009 comparative period included five months of post-merger results, compared to a full year in

2010. Other positive contributions to operating earnings included wider light/heavy and light/sour synthetic crude pricing differentials and stronger distillate cracking margins. These were somewhat offset by lower utilization of the Sarnia refinery due to Enbridge pipeline disruptions that limited crude availability in the latter part of 2010.

Marketing activities contributed operating earnings of $259 million in 2010, compared with $152 million in 2009. The increase reflected higher sales volumes due to the additional seven months of operations from the retail, wholesale and lubricants businesses included in 2010 as a result of the timing of the merger.

### Continuing Operations

**Operating Earnings from Continuing Operations**
($ millions)




### Volumes

| Year ended December 31 (thousands of m³/d) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Refined Product Sales | | | |
| Gasoline | | | |
| Eastern North America | **22.2** | 14.6 | 7.9 |
| Western North America | **18.9** | 13.0 | 8.0 |
| | **41.1** | 27.6 | 15.9 |
| Distillates | | | |
| Eastern North America | **12.4** | 8.8 | 5.2 |
| Western North America | **18.5** | 9.5 | 5.6 |
| | **30.9** | 18.3 | 10.8 |
| Other, including petrochemicals | **15.8** | 9.0 | 4.8 |
| Total refined product sales | **87.8** | 54.9 | 31.5 |
| Crude oil processed by Suncor | | | |
| Eastern North America | **30.5** | 19.3 | 11.0 |
| Western North America | **34.6** | 22.9 | 13.7 |
| Total crude oil processed by Suncor | **65.1** | 42.2 | 24.7 |

Total sales of refined petroleum products averaged 87,800 $m^3$/d, compared to 54,900 $m^3$/d in 2009. Sales volumes increased largely due to the merger. After the completion of the merger in 2009, total sales of refined petroleum product averaged 84,800 $m^3$/d during the last five months of 2009.

Overall, refinery utilization averaged 92% in 2010, compared to a post-merger rate of 92% in 2009, which included twelve months of results for the Sarnia and Commerce City refineries and five months for the Edmonton and Montreal refineries. Sarnia ran less crude in the latter part of 2010 primarily due to Enbridge pipeline disruptions that limited western Canadian crude availability. This shortfall was partially mitigated by processing foreign light crudes and higher utilization at the Montreal refinery to maintain product supply in Ontario.

### Margins

Gross margins, in absolute terms, increased in 2010 compared to 2009 due to the additional volume resulting from the merger and improved refining crack spreads that resulted in higher price realizations for our refined products.

Refining and product supply activities benefited from more favourable light/heavy and light/sour synthetic crude price differentials and an improved business environment in 2010, with higher cracking margins in every major market area and stronger product demand compared to 2009. The Edmonton refinery benefited from lower feedstock costs due to wider light/heavy and light/sour synthetic crude differentials. The Sarnia refinery was negatively impacted by the Enbridge pipeline service disruptions that restricted deliveries of lower cost sour crude received from Western Canada and necessitated processing more expensive offshore crude.

Marketing activities continued to benefit from the merger in 2010 with increased volumes. However, the gross petroleum margin on a per litre basis was lower, compared to 2009, due to the broader geographic market base and product offering mix of the merged retail network.

### Operating Expenses

Operating expenses were higher in 2010, compared to 2009, primarily due to the inclusion of an additional seven months of operations in 2010 as a result of the timing of the merger.

### DD&A

DD&A expense was higher in 2010, primarily due to the larger merged asset base.

### Planned Maintenance Turnarounds

Major maintenance turnaround work was completed in 2010 at three of the four refineries and the lubricants production facility. Major turnaround work is planned in

2011 at the Sarnia, Edmonton and Commerce City refineries.

For planned turnarounds, the company enters into transactions to ensure sufficient additional finished product is available to mitigate the impact of lost production on customers.

## Corporate, Energy Trading and Eliminations

Corporate, Energy Trading and Eliminations includes the company's investment in renewable energy projects, results related to energy trading activities with third-parties, and activities not directly attributable to any operating segment.

## Operating Earnings Reconciliation

| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Net (loss) earnings** | **(442)** | 104 | (805) |
| Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt | **(372)** | (798) | 852 |
| Mark-to-market valuation of stock-based compensation | **19** | 58 | (101) |
| Merger and integration costs | **86** | 151 | — |
| Impact of income tax rate adjustments on future income tax liabilities | **—** | 5 | — |
| **Operating loss** [1] | **(709)** | (480) | (54) |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

| Year ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Operating earnings (loss)** [1] | | | |
| Renewable energy | **33** | 29 | 28 |
| Energy trading | **53** | 44 | 56 |
| Corporate | **(808)** | (460) | (129) |
| Group eliminations | **13** | (93) | (9) |
| | **(709)** | (480) | (54) |
| **Cash flow used in operations** [1] | **(973)** | (653) | (37) |

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

The net loss in 2010 for the Corporate, Energy Trading and Eliminations segment was $442 million, compared to net earnings of $104 million in 2009. The decrease in net earnings of 2010 was primarily due to a smaller unrealized foreign exchange gain on U.S. dollar denominated long-term debt compared to 2009. Operating loss in 2010 was higher than 2009 primarily due to captive insurance payments made in 2010 and additional interest expense.

## Renewable Energy

Renewable energy contributed $33 million of operating earnings in 2010, which was comparable with those in 2009 ($29 million). Suncor has an ethanol plant and joint ownership in four wind farm projects. The expansion to double the design capacity of the ethanol plant from 200 million litres per year to 400 million litres per year was completed in January 2011. There are two additional wind farm projects under construction.

## Energy Trading

Energy trading activities primarily involve marketing and trading of crude oil, natural gas, refined products and byproducts, and the use of financial derivatives. These activities resulted in operating earnings of $53 million in 2010 compared to $44 million in 2009. In 2010, earnings were driven by buying heavy oil in Western Canada at wide price differentials relative to WTI and transporting this product to more favourable markets. In 2009 results were positively impacted by realized physical gains on crude inventory positions.

## Corporate and Eliminations

Corporate experienced an operating loss of $808 million in 2010, compared to an operating loss of $460 million in 2009. The increased operating loss was primarily due to captive insurance payments made in the first and third quarters of 2010 and additional interest expense, resulting from additional debt acquired through the merger.

Group eliminations reflects the elimination of profit on crude oil sales between Oil Sands or East Coast Canada and Refining and Marketing, where profits are realized when the products are sold to third parties. During 2010, $13 million of profits previously eliminated were recognized in earnings, compared to profits of $93 million that were eliminated in 2009.

## QUARTERLY FINANCIAL DATA

| ($ millions, except as noted) | **2010 Three months ended** Dec 31 | Sept 30 | June 30 | Mar 31 | 2009 Three months ended Dec 31 | Sept 30 | June 30 | Mar 31 |
|---|---|---|---|---|---|---|---|---|
| **Revenues (net of royalties)** | | | | | | | | |
| Continuing operations | **9 789** | 8 636 | 8 979 | 6 946 | 7 236 | 8 257 | 4 748 | 4 607 |
| Discontinued operations [1] | **150** | 211 | 207 | 302 | 400 | 186 | 20 | 26 |
| | **9 939** | 8 847 | 9 186 | 7 248 | 7 636 | 8 443 | 4 768 | 4 633 |
| **Net earnings (loss)** | | | | | | | | |
| Continuing operations | **1 297** | 609 | 318 | 464 | 476 | 965 | (46) | (189) |
| Discontinued operations | **56** | 413 | 162 | 252 | (19) | (36) | (5) | — |
| | **1 353** | 1 022 | 480 | 716 | 457 | 929 | (51) | (189) |
| **Net earnings (loss) from continuing operations per common share** | | | | | | | | |
| Basic | **0.83** | 0.39 | 0.20 | 0.30 | 0.30 | 0.72 | (0.05) | (0.20) |
| Diluted | **0.82** | 0.39 | 0.20 | 0.30 | 0.30 | 0.71 | (0.05) | (0.20) |
| **Net earnings (loss) per common share** [2] | | | | | | | | |
| Basic | **0.87** | 0.65 | 0.31 | 0.46 | 0.29 | 0.69 | (0.06) | (0.20) |
| Diluted | **0.86** | 0.65 | 0.31 | 0.45 | 0.29 | 0.68 | (0.06) | (0.20) |
| **Operating earnings (loss)** [2],[3] | | | | | | | | |
| Continuing operations | **890** | 600 | 752 | 220 | 319 | 398 | 61 | 398 |
| Discontinued operations | **56** | 75 | 53 | 84 | 23 | (36) | (5) | — |
| | **946** | 675 | 805 | 304 | 342 | 362 | 56 | 398 |
| **Operating earnings per common share** [2],[3] | **0.60** | 0.43 | 0.52 | 0.19 | 0.22 | 0.29 | 0.06 | 0.43 |
| **Cash flow from operations** [2],[4] | **2 144** | 1 630 | 1 758 | 1 124 | 1 129 | 574 | 295 | 801 |
| **Return on capital employed** (twelve months ended) (%) [4],[5] | **10.1** | 7.9 | 7.0 | 4.9 | 2.6 | 3.7 | 7.3 | 16.0 |

(1) Discontinued operations per note 6 of the audited Consolidated Financial Statements, excluding gain on disposal.
(2) Includes continuing and discontinued operations.
(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.
(4) Non-GAAP measure. See the reconciliation in the Non-GAAP Financial Measures Advisory section of this MD&A.
(5) Excludes capitalized costs related to major projects in progress.

In addition to changes in production and product sales, commodity price fluctuations and the impacts of changes to foreign exchange rates, variations in quarterly net earnings from continuing operations during 2010 and 2009 include the following factors:

- The fourth quarter of 2010 included a gain for the redetermination of Terra Nova oilfield working interests and an adjustment to royalty expense with respect to the modification to the BVM calculation.
- The third quarter of 2010 included impairments to Natural Gas assets.
- The second quarter of 2010 included impairments of Oil Sands assets that were being used in the development of an alternative extraction process and Natural Gas properties that the company decided not to pursue.
- The first quarter of 2010 and the fourth quarter of 2009 were negatively impacted by upgrader fires that significantly reduced Oil Sands production and altered our product mix.
- The fourth quarter of 2009 included a gain from the impacts of income tax rate adjustments, partially offset by losses on asset disposal.
- The third quarter of 2009 included the additional upstream production and refining product sales resulting from the merger and an effective gain on a pre-existing contract with Petro-Canada.
- The first quarter of 2009 included significant costs associated with the deferral of certain growth projects.

## CONSOLIDATED FINANCIAL ANALYSIS – FOURTH QUARTER 2010

### Fourth Quarter 2010 Highlights

- Results from Refining and Marketing in the fourth quarter of 2010 were strong, with net earnings of $372 million, which was more than double the fourth quarter of 2009, primarily as a result of higher realized margins and increased refinery utilization. Total sales of refined petroleum products averaged 91,100 $m^3$/d during the fourth quarter of 2010 compared to 82,900 $m^3$/d in the fourth quarter of 2009, reflecting more reliable operations in all of the company's facilities and improved product demand.
- Total upstream production in the fourth quarter was 625,600 boe/d, compared to 638,200 boe/d in the fourth quarter of 2009. However, production from continuing operations increased to 605,400 boe/d in the fourth quarter of 2010, from 544,500 boe/d in the fourth quarter of 2009. Overall, lower production volumes were primarily due to asset sales in Suncor's Natural Gas and International and Offshore businesses, partially offset by production increases in continuing International and Offshore operations and improved operational reliability at Oil Sands.

### Net Earnings by Segment

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| **Continuing operations** | | | | |
| Oil Sands | **487** | 236 | **1 492** | 557 |
| Natural Gas | **(65)** | (55) | **(277)** | (185) |
| International and Offshore | **452** | 230 | **1 114** | 323 |
| Refining and Marketing | **372** | 151 | **801** | 407 |
| Corporate, Energy Trading and Eliminations | **51** | (86) | **(442)** | 104 |
| | **1 297** | 476 | **2 688** | 1 206 |
| **Discontinued operations** | | | | |
| Natural Gas | **(2)** | 5 | **506** | (14) |
| International and Offshore | **58** | (24) | **377** | (46) |
| | **56** | (19) | **883** | (60) |
| **Net earnings** | **1 353** | 457 | **3 571** | 1 146 |

### Upstream Production Volumes

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| (mboe/d) | **2010** | 2009 | **2010** | 2009 |
| **Continuing operations** | | | | |
| Oil Sands (includes Syncrude) | **363.8** | 318.2 | **318.2** | 306.7 |
| Natural Gas | **71.5** | 76.8 | **72.0** | 47.0 |
| International and Offshore | **170.1** | 149.5 | **170.9** | 58.0 |
| | **605.4** | 544.5 | **561.1** | 411.7 |
| **Discontinued operations** | | | | |
| Natural Gas | **1.5** | 50.6 | **23.8** | 27.4 |
| International and Offshore | **18.7** | 43.1 | **30.2** | 16.9 |
| | **20.2** | 93.7 | **54.0** | 44.3 |
| **Total** | **625.6** | 638.2 | **615.1** | 456.0 |

### Downstream Sales Volumes

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($m^3$/d) | **2010** | 2009 | **2010** | 2009 |
| **Total refined product sales** | **91.1** | 82.9 | **87.8** | 54.9 |

## Oil Sands

Oil Sands net earnings for the fourth quarter of 2010 were $487 million, compared to $236 million for the fourth quarter of 2009. Net earnings in the fourth quarter of 2010 compared to 2009 included the impacts of a bitumen valuation royalty provision recovery, which was partially offset by lower gains on change in fair value of commodity derivatives used for risk management and lower costs related to deferral of growth projects.

Oil Sands production, excluding Suncor's share of production from Syncrude, was 17% higher in the fourth quarter of 2010 compared to the fourth quarter of 2009. Higher bitumen supply from all of the Oil Sands assets contributed to a record quarterly production average volume of 325,900 bpd in the fourth quarter of 2010. The prior year quarter was negatively impacted by the fire that occurred in December 2009 at Upgrader 2.

Syncrude production decreased 4% in the fourth quarter of 2010, compared to the fourth quarter of 2009, primarily due to upgrader outages that occurred during the quarter.

Oil Sands benefited from higher benchmark crude oil prices in the fourth quarter of 2010 compared to the fourth quarter of 2009, partially offset by wider heavy crude oil differentials and the stronger Canadian dollar relative to the U.S. dollar. Enbridge pipeline disruptions limited the export capacity of heavy crude products from Western Canada, reducing both sour crude and bitumen price realizations during the fourth quarter of 2010.

The six-week planned turnaround for Upgrader 2 that began in September continued for three weeks into the fourth quarter of 2010. Hydrogen supply and hydrotreating issues, which also surfaced initially in the third quarter of 2010, increased the percentage of sour crude produced during the fourth quarter and negatively impacted product mix and price realizations.

## Natural Gas

Natural Gas had a net loss from continuing operations of $65 million in the fourth quarter of 2010, compared with a net loss of $55 million in the fourth quarter of 2009. Net loss from continuing operations in the fourth quarter of 2010 included the impacts of a $13 million write-down of spare parts inventory and higher costs related to stock-based compensation. Gross production from continuing operations decreased by 7% in the fourth quarter of 2010, compared to the fourth quarter of 2009, mainly due to natural declines.

## International and Offshore

International and Offshore had net earnings from continuing operations of $452 million in the fourth quarter of 2010, compared to $230 million in the fourth quarter of 2009. Net earnings in the fourth quarter of 2010 included the settlement payment of $295 million (pre-tax) due to Suncor related to the Terra Nova redetermination. Net earnings from continuing operations in the fourth quarter of 2010 also included increased production from continuing operations and higher price realizations.

Overall, production from continuing operations was higher in the fourth quarter of 2010, compared to the fourth quarter of 2009, primarily due to Syrian gas production coming on-stream in the second quarter of 2010.

## Refining and Marketing

Refining and Marketing had net earnings of $372 million in the fourth quarter of 2010, compared to $151 million in the fourth quarter of 2009, primarily due to higher margins in the fourth quarter of 2010. Increased production enabled refining and product supply activities to benefit from an improved business environment, with higher cracking margins in every major market area and stronger product demand compared to the fourth quarter of 2009. The Sarnia refinery was negatively impacted from the lingering effects of the Enbridge crude pipeline disruptions that restricted deliveries of lower cost sour crudes received from Western Canada and necessitated processing of more expensive offshore crude. The Edmonton refinery benefited from lower feedstock costs due to wider light/heavy and light/sour synthetic crude differentials.

Total sales of refined petroleum products increased 10% due to stronger operations and improved product demand as the economy recovered in the fourth quarter of 2010, compared to the fourth quarter of 2009. Overall, refinery utilization averaged 94% in the fourth quarter of 2010, compared to 90% in the fourth quarter of 2009, due largely to fewer scheduled maintenance turnarounds. The reductions to the Sarnia refinery production were partially offset by increasing throughputs at the Montreal refinery to support Ontario market demands.

Marketing network sales volumes in the fourth quarter of 2010 were marginally higher than in the fourth quarter of 2009. Strong sales in both the retail and wholesale divisions were partially offset by the loss of volume associated with the divestment of merger remedy sites.

## Corporate, Energy Trading and Eliminations

Net earnings for the Corporate, Energy Trading and Eliminations were $51 million in the fourth quarter of 2010, compared to a net loss of $86 million in the fourth quarter of 2009. The increase in net earnings was due primarily to a higher unrealized foreign exchange gain on U.S. dollar denominated long-term debt.

## CAPITAL INVESTMENT UPDATE

Suncor spent $5.7 billion on capital and exploration in 2010, which was marginally higher than Suncor's original 2010 budget of $5.5 billion. The capital expenditures were primarily focused on sustaining safe and reliable existing operations throughout the company, and the continued development of the Firebag Stage 3 and 4 expansions.

| Year ended December 31 | **2010** | 2009 |
|---|---|---|
| Oil Sands | **3 709** | 2 831 |
| Natural Gas | **178** | 320 |
| International and Offshore | **1 096** | 666 |
| Refining and Marketing | **667** | 380 |
| Corporate, Energy Trading and Renewable Energy | **360** | 70 |
| Less: Capitalized Interest | **(301)** | (136) |
| Total | **5 709** | 4 131 |

This capital investment update contains forward-looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

### Oil Sands

Oil Sands capital expenditures were $3.709 billion in 2010. Growth spending in 2010 was primarily focused on the construction of Firebag Stage 3.

The company is continuing with its planned in situ growth initiatives:

- Firebag Stage 3 – The planned expansion is targeted to begin production late in the second quarter of 2011, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter. The 2010 expenditures focused primarily on construction of cogeneration and central plant facilities and well pads.
- Firebag Stage 4 – This project was put into safe mode in early 2009, then restarted in late 2010. The planned expansion is targeted to begin production late in the first quarter of 2013, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter. The 2010 expenditures focused primarily on remobilization of workforce.

As of December 31, 2010, cumulative capital expenditures for the Firebag Stages 3 and 4 expansions were $4.3 billion.

Capital expenditures on Suncor's $TRO_{TM}$ tailings reclamation technology related to its implementation across existing operations. Project activities during 2010 included engineering, procurement of certain long-lead items, site preparation and construction of temporary facilities. The project is scheduled to be completed by the end of 2012 at a cumulative capital cost in excess of $1.0 billion.

The MNU project was also taken out of safe mode and restarted in 2010. As of December 31, 2010, cumulative capital expenditures were $763 million. Project activities during 2010 consisted primarily of the remobilization of the construction workforce to complete the remaining scope of work. The project is scheduled to be completed by the end of 2011 and will provide additional hydrogen and hydrotreating capacity to increase the percentage mix of sweet synthetic crude oil production.

With the growth plans announced in December 2010 involving the strategic partnership with Total, the company plans to restart the Voyageur Upgrader in 2011 and plans to begin the Fort Hills mine development.

- Voyageur Upgrader – The focus in 2011 is anticipated to be the remobilization of the workforce, the confirmation of the current design and the modification of the project execution plans.
- Fort Hills – The focus in 2011 is anticipated to be design base memorandum engineering.

In 2010, Suncor also focused on a number of sustaining capital projects required to maintain the mining, upgrading, extraction and in situ assets operating effectively. Major planned maintenance and turnarounds were completed on Upgrader 2 in the spring and fall.

### Natural Gas

Natural Gas is focused on improving profitability by investing in low risk drilling programs conducive to low cost repeatable drilling and those with a high percentage of liquids production. In 2010, Natural Gas spent $178 million on exploration and development activities, of which $8 million was related to assets disposed of during the year. In 2010, spending was focused primarily on unconventional gas opportunities, as well as land acquisitions in northeast British Columbia.

Suncor's key shallow gas producing properties near Medicine Hat, in southeastern Alberta, continued with drilling and tie-in activity. In total, 324 wells were drilled in 2010, with overall production from this area averaging 72 mmcfe/d during the year.

Two significant drilling programs began in the fourth quarter of 2010: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Tie-in activities for both programs started in the first quarter of 2011.

### International and Offshore

International and Offshore spent $264 million on capital and exploration in 2010 related primarily to the White Rose and Hibernia areas of East Coast Canada operations.

- At North Amethyst, first oil was achieved May 31, 2010. Facility construction was completed during the year and the remainder of the project is focused on development drilling of 11 wells in total and is planned to continue until 2013. Data provided by a delineation well will be used to optimize future well placement.
- Development drilling for the first phase of the West White Rose portion of the White Rose Extensions began in August 2010, with first oil expected by mid-2011. Drilling results from the first phase, combined with production evaluation and ongoing reservoir evaluation, are expected to define the full field development scope.
- Capital spending continues on the Hibernia South Extension project, where early production from the unit is expected in mid-2011.
- The contract for front-end engineering and design and topsides engineering, procurement and construction for Hebron was awarded in September 2010. The development plan approval submission is expected to be made in the second quarter of 2011 with first oil expected in 2017.

International and Offshore expenditures on capital and exploration in 2010 related to its other operations were $832 million, of which $169 million was related to assets disposed of during the year. Spending has been primarily focused on exploration drilling in Libya, development spending in the U.K. and Syria, and exploration drilling in Norway.

- Seismic survey projects continue to acquire data in relation to the Libya EPSAs. Two exploration wells, four appraisal wells and 26 development wells were completed in the year with seismic data acquisition continuing into the first quarter of 2011.
- The Buzzard enhancement project, which included the shutdown and the tie-in of a fourth platform, was completed and staged commissioning began on the sulphur handling platform in October 2010. Production disruptions during ramp-up have been less than anticipated to date. Commissioning of the new platform will continue into the first quarter of 2011.
- In Syria, facility development was completed to support first commercial gas and condensate production, which was achieved in April 2010, and first liquefied petroleum gas, which was achieved in May 2010 from the Ebla gas project. First oil was achieved in December 2010.
- Following the Beta Brent discovery offshore Norway completed earlier in 2010, the Beta Statfjord appraisal well was successfully tested. Additional appraisal well testing is required to delineate the discovery further.

### Refining and Marketing

Refining and Marketing spent $667 million on capital in 2010, primarily focused on planned turnarounds and rebranding former Sunoco retail sites to the Petro-Canada brand.

Major maintenance turnaround work was completed in 2010 at three of the four refineries and the lubricants production facility to support continued safe and reliable operations.

### Corporate, Energy Trading and Eliminations

Corporate capital expenditures were $360 million in 2010, with a focus on merger integration related activities and renewable energy. Work continues to integrate legacy Suncor and legacy Petro-Canada systems onto one common platform, where appropriate, as well as integrate processes, information and technology.

Construction on the Wintering Hills wind power project, which began in the second half of 2010, is expected to be completed by the end of 2011. At peak operation, the project is expected to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of carbon dioxide ($CO_2$) per year.

Construction on the Kent Breeze wind power project, which commenced in the second half of 2010, is expected to be completed by mid-2011.

Suncor's ethanol plant, located in Sarnia, Ontario, has a current capacity of 400 million litres per year, after a plant expansion was completed in January 2011 that doubled the capacity of the ethanol plant. The plant displaces the equivalent of 300,000 tonnes of $CO_2$ per year.

## LIQUIDITY AND CAPITAL RESOURCES

| At December 31 ($ millions, except ratios) | **2010** | 2009 |
|---|---|---|
| Working capital (deficit)[(1)] | **1 257** | (324) |
| Short-term debt | **2** | 2 |
| Current portion of long-term debt | **518** | 25 |
| Long-term debt | **11 669** | 13 855 |
| Total debt | **12 189** | 13 882 |
| Less: Cash and cash equivalents | **1 077** | 505 |
| Net debt | **11 112** | 13 377 |
| Shareholders' equity | **36 721** | 34 111 |
| Total capitalization (total debt and shareholders' equity) | **48 910** | 47 993 |
| Total debt to debt plus shareholders' equity (%)[(2)] | **25** | 29 |

| Year ended December 31 | **2010** | 2009 |
|---|---|---|
| ROCE (%) – excludes capitalized costs related to major projects[(3)] | **10.1** | 2.6 |
| ROCE (%) – includes capitalized costs related to major projects[(3)] | **7.4** | 1.8 |
| Net debt to cash flow from operations (times)[(4)] | **1.7** | 4.8 |
| Interest coverage on long-term debt (times) | | |
| Net earnings[(5)] | **8.4** | 3.0 |
| Cash flow from operations[(3),(6)] | **11.9** | 7.2 |

(1) Calculated as current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt and future income taxes. Current assets and liabilities of discontinued operations are excluded.
(2) Short-term debt plus long-term debt divided by the sum of short-term debt, long-term debt and shareholders' equity.
(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.
(4) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations.
(5) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.
(6) Cash flow from operations plus current income taxes and interest expense divided by the sum of interest expense and capitalized interest.

### Capital Resources

Suncor's capital resources consist primarily of cash flow from operations and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2011 capital spending program and to meet current and long-term working capital requirements through cash flow from operations, proceeds from the agreement with Total, other planned asset divestitures and its available committed credit facilities. The expected proceeds from the agreement with Total are approximately $1.75 billion, subject to closing adjustments. The company's cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available in the debt capital markets at commercial terms and rates.

### Financing Activities

Management of debt levels continues to be a priority given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

At December 31, 2010, Suncor's net debt was $11.1 billion, compared to $13.4 billion at December 31, 2009. Net debt decreased by $2.3 billion largely due to proceeds from asset dispositions being directed to debt retirement and the appreciation of the Canadian dollar relative to the U.S. dollar through the period. Unutilized lines of credit at December 31, 2010 were approximately $5.3 billion, compared to $4.2 billion at December 31, 2009.

A summary of available and unutilized credit facilities is as follows:

| ($ millions) | 2010 |
|---|---|
| Facility that has a term period of one year and expires in 2011 | **4** |
| Facility that is fully revolving for a period of four years and expires in 2013 | **199** |
| Facilities that are fully revolving for a period of five years and expire in 2013 | **7 320** |
| Facilities that can be terminated at any time at the option of the lenders | **461** |
| Total available credit facilities | **7 984** |
| Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans | **(1 982)** |
| Credit facilities supporting standby letters of credit | **(713)** |
| Total unutilized credit facilities | **5 289** |

Interest expense on debt continues to be influenced by the composition of the debt portfolio, and is currently benefiting from short-term floating interest rates that remain at low levels, compared to historical short-term rates. To manage fixed versus floating rate exposure, we have entered into fixed to floating interest rate swaps with investment grade counterparties. At December 31, 2010, the company had interest rate swaps relating to $200 million of its fixed-rate debt, due in August 2011.

Suncor has an operating working capital of $1.257 billion at December 31, 2010, compared to a deficiency of $324 million at December 31, 2009. The working capital change from a deficit to a surplus during 2010 was primarily a result of increased accounts receivable balances, resulting from higher volumes and prices and the recording of the Terra Nova redetermination receivable, partially offset by an increase in accounts payable as a result of higher royalties payable from increased production.

Suncor is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not be more than 60% of its total capitalization. At December 31, 2010, total debt to total capitalization was 25% (December 31, 2009 – 29%). The company is also currently in compliance with all operating covenants.

## Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions, and may require the company to post additional collateral under certain contracts.

All of the company's debt ratings are investment grade. The company's current long-term senior debt ratings are BBB+, with a Stable Outlook from Standard & Poor's (S&P); A(low), with a Stable Trend from Dominion Bond Rating Service (DBRS); and Baa2, with a Stable Outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS. These have not changed from December 31, 2009.

## Outstanding Shares

| At December 31, 2010 (thousands) | |
|---|---|
| Common shares | 1 565 489 |
| Common share options – exercisable and non-exercisable | 67 638 |
| Common share options – exercisable | 46 266 |

As at February 24, 2011, the total number of common shares outstanding was 1,570,039,616 and the total number of exercisable and non-exercisable common share options outstanding was 67,838,293.

## Aggregate Contractual Obligations

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

| | | Payments Due by Period | | | |
|---|---|---|---|---|---|
| ($ millions) | Total | 2011 | 2012-2013 | 2014-2015 | Later Years |
| Fixed-term debt and revolving-term debt (1) | 11 903 | 2 482 | 311 | 406 | 8 704 |
| Interest payments on fixed-term debt | 11 015 | 609 | 1 175 | 1 131 | 8 100 |
| Capital lease payments | 718 | 36 | 74 | 74 | 534 |
| Asset retirement obligations (2) | 7 434 | 127 | 330 | 244 | 6 733 |
| Operating lease agreements, pipeline capacity and energy services commitments (3) | 13 256 | 1 089 | 1 870 | 1 623 | 8 674 |
| Exploration work commitments | 425 | 137 | 288 | — | — |
| Other long-term obligations (4) | 649 | 239 | 359 | 51 | — |
| **Total** | 45 400 | 4 719 | 4 407 | 3 529 | 32 745 |

(1) Includes $8.108 billion of U.S. and $1.800 billion of Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2039. Interest rates vary from 4.00% to 9.25%. We entered into interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2010 of 1.9% on $200 million of our Medium Term Notes. Approximately $1.982 billion of revolving-term debt with an effective interest rate of 1.2% was issued and outstanding at December 31, 2010.

(2) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(3) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States. The figure also includes commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company.

(4) Includes Libya EPSA signature bonus and Fort Hills purchase obligations. See note 18 to the Consolidated Financial Statements.

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice, including commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

## FINANCIAL INSTRUMENTS

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars to manage exposure to fluctuations in commodity prices and foreign exchange rates and to optimize the company's position with respect to interest expense. The company also uses physical and financial energy derivatives to earn trading revenues.

To estimate fair value of financial instruments, the company uses quoted market prices when available, or models that utilize observable market data. In addition to market information, Suncor incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. Inputs used are characterized in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

### Hedge Accounting for Fair Value Hedges

At December 31, 2010, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to $200 million of its fixed-rate debt. The fair value of these swaps was $8 million at December 31, 2010 (December 31, 2009 – $18 million), and was recorded in accounts receivable in the Consolidated Balance Sheets.

### Risk Management Activities

Suncor uses derivative contracts to hedge risks related to purchases and sales of commodities, to manage exposure to interest rates, and to hedge risks specific to individual transactions. Gains or losses on risk management derivatives are recorded in the Consolidated Statements of Earnings in the same caption as the related transaction. The earnings impact associated with our risk management derivatives for the year ended December 31, 2010 was a net pre-tax gain of $89 million (2009 – pre-tax loss of $1.024 billion). There are no significant risk management derivative contracts outstanding at December 31, 2010.

## Energy Trading Activities

Suncor uses crude oil, natural gas and refined product derivative contracts to earn supply and trading revenues. The results of these supply and trading activities are reported as energy supply and trading activities revenues and expenses in the Consolidated Statements of Earnings. The net pre-tax gain associated with our energy trading activities in 2010 was $81 million (2009 – pre-tax loss of $70 million).

The change in fair value of derivatives pertaining to risk management and energy trading activities are as follows:

| ($ millions) | **2010** |
|---|---|
| Fair value of contracts at December 31, 2009 | (359) |
| Fair value of contracts realized during the period | **115** |
| Change in fair value during the period | **170** |
| **Fair value of derivative contracts outstanding at December 31, 2010** | **(74)** |

The fair value of derivatives pertaining to risk management and energy trading activities are recorded in the Consolidated Balance Sheets as follows:

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Accounts receivable | **19** | 213 |
| Accounts payable and accrued liabilities | **(93)** | (572) |
| | **(74)** | (359) |

## Risks Associated with Derivative Financial Instruments

Suncor's price risk management strategies are subject to periodic management reviews to determine appropriate hedge requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth.

Suncor may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date.

Energy supply and trading activities are governed by a separate risk management group which reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instrument contracts and additional discussion of exposure to risks and our mitigation activities, see note 21 to the 2010 audited Consolidated Financial Statements.

## RISK FACTORS

We are continually working to mitigate the impact of potential risks to our business. This process includes an entity-wide risk review. The internal review is completed annually to help ensure that all significant risks are identified and appropriately managed. The following provides a list of some of the risk factors relating to Suncor and our business. A detailed discussion of additional risk factors related to Suncor and our business is presented in our most recent Annual Information Form (AIF)/Form 40-F, filed with securities regulatory authorities.

## Volatility of Commodity Prices and Exchange Rate Fluctuations

Our future financial performance is closely linked to crude oil prices and, to a lesser extent, natural gas prices. The prices of these commodities can be influenced by global and regional supply and demand factors. Worldwide economic growth, political developments, compliance or non-compliance with quotas imposed upon members of the Organization of the Petroleum Exporting Companies, and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations in our Natural Gas segment are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond our control and can result in a high degree of price volatility, not only in crude oil and natural gas prices but also fluctuating price differentials between heavy and light grades of crude oil, which can impact prices for sour crude oil and bitumen. Oil and natural gas prices have fluctuated widely in recent years. Given the continued global economic uncertainty, we expect continued volatility and uncertainty in crude oil and natural gas prices in the near term and beyond, with the possibility that crude oil prices could revert to the low levels experienced in 2008 and 2009. A prolonged period of low crude oil and natural gas prices could affect the value of our crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production on some properties. Accordingly, low natural gas prices and low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow.

For the year ended December 31, 2010, we conducted an assessment of the carrying value of our assets to the extent required by Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of our assets could be subject to downward revisions, and our earnings could be materially adversely affected.

Our downstream business is sensitive to wholesale and retail margins for its refined products, including, but not limited to, gasoline, diesel, petrochemicals and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil, and fluctuations in supply and demand for refined products. We expect that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue. As a result, the operating results for our Refining and Marketing business unit can be expected to fluctuate and may be materially adversely affected.

Our 2010 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar, and are also affected by the exchange rates between the Canadian dollar, the euro and the British pound. These exchange rates may vary substantially and may give rise to foreign currency exposure, either favourable or unfavourable, creating another element of uncertainty. To the extent such fluctuation is unfavourable, it may have a material adverse effect on our business, financial condition, results of operation and cash flow.

### Government Regulation

The company, and the oil and gas industry generally, operates under federal, provincial, state and municipal legislation in numerous countries. This industry is also subject to regulation and intervention by governments in such matters as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, the reduction of greenhouse gas (GHG) and other emissions, the export of crude oil, natural gas and other products, the awarding or acquisition of exploration and production, oil sands or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields and mine sites (including restrictions on production), and possibly expropriation or cancellation of contract rights. The following subsections provide more information on some of these regulations.

### Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Some of the issues that are or may in future be subject to environmental regulation include:

- The possible cumulative regional impacts of oil sands development;
- The manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- The need to reduce or stabilize various emissions to air;
- Withdrawals, use of, and discharges to water;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or
- U.S. state or federal calculation and regulation of fuel life cycle carbon content.

Changes in environmental regulation could have a material adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production, distribution costs and financial results. For example, requirements for cleaner burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on us. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for cleanup costs and damages, and the loss of important licences and permits, which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

## Climate Change

While there is a well-defined GHG regulatory system with targets in place for all large industrial facilities in the province of Alberta, no other North American jurisdiction has yet enacted similar strict compliance measures. Suncor anticipates that this current situation will be replaced within the next few years by a series of regional regulatory regimes, or with an all-encompassing federal regime. In general, therefore, there remains uncertainty around the outcome and impacts of climate change and environmental laws and regulations (whether currently in force, or proposed laws and regulations as described herein or future laws and regulations); it is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time.

The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear what approach the U.S. will take, or when, it also is unclear whether the federal government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

British Columbia has drafted regulations for a cap-and-trade system, as well as offset regulations, which are intended to be finalized later in 2011. The impact of these regulations cannot be quantified at this time, given the current lack of detail on how the system will operate.

While forthcoming laws and regulations may impose significant liabilities on a failure to comply with their requirements, the cost of meeting new environmental and climate change regulations is not expected to be so high as to cause a material disadvantage, or damage to our competitive positioning.

As part of our ongoing business planning, Suncor assesses potential costs associated with carbon dioxide ($CO_2$) emissions in our evaluation of future projects, based on our current understanding of pending and possible greenhouse gas regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. We expect that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on our strategy, using as a base case price range of $15-$45 per tonne of $CO_2$ equivalent, applied against a range of regulatory policy options and price sensitivities.

California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS); although Suncor does not actively market into the state of California, the implications of other states adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands derived crude, if the importing jurisdictions fail to acknowledge the mandated 12% reduction requirement imposed by the company's exporting jurisdiction (Alberta).

While it appears fairly certain that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the $CO_2$ unit intensity of our operations, the absolute $CO_2$ emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

## Reclamation

There are risks associated with our ability to complete reclamation work, specifically reclaiming tailings ponds, which contain water, clay and residual bitumen produced through the extraction process. In February 2009, the Energy Resources Conservation Board (ERCB) of the Government of Alberta released a directive, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. The directive establishes performance criteria for tailings operations, a requirement for specific approval and monitoring of tailings ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations.

On October 15, 2009, the company applied to the ERCB and Alberta Environment for permission to amend its existing and/or approved operations east of the Athabasca River to move to the company's new planned $TRO_{TM}$ strategy. In 2010, the company received regulatory approval for a new tailings management plan using the company's proprietary $TRO_{TM}$ tailing management process. It is anticipated that $TRO_{TM}$ will allow the company to accelerate the pace of reclamation and reduce costs in the long term.

At this time, no ponds have been fully reclaimed using this technology. The success of the $TRO_{TM}$ and the time to reclaim tailings ponds could increase or decrease the current asset retirement cost estimates. Our failure to adequately implement our reclamation plans could have a material adverse effect on our business, financial condition, results of operations and cash flow.

## Royalties

The following risk factors could cause royalty expenses to differ materially from current estimates and impact the royalties payable.

### *Alberta*

The Alberta government enacted new Bitumen Valuation Methodology (BVM) (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM for future years. For Suncor's mining operations, the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted. For the years 2009 and 2010, Suncor filed non-compliance notices with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. Suncor has also filed with the Crown a Notice of Commencement of Arbitration under the Suncor RAA. Syncrude has also filed a non-compliance notice in respect of the determination of the bitumen value under its agreements with the Crown. The final determination of these matters may have a material impact on future royalties payable to the Crown.

The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. Further clarification of some allowed cost business rules is still expected. The terms of Suncor's RAA, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for our mining operations. However, potential changes and the interpretation of the allowed cost regulations could, over time, have a significant impact on the amount of royalties payable.

In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project, changes to the New Royalty Framework by the Government of Alberta, changes in other legislation, and the occurrence of unexpected events.

### *East Coast Canada Royalties*

Suncor and the Government of Newfoundland and Labrador are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalty payments to the Crown. In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project, changes resulting from regulatory audits of prior year filings, further changes to applicable royalty regimes by the Government of Newfoundland and Labrador, changes in other legislation, and the occurrence of unexpected events.

### *Production Sharing Contracts*

Payments pursuant to PSCs could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs; changes resulting from regulatory audits of prior year filings, further changes to applicable royalty regimes by governments or other applicable regulatory bodies, changes in other legislation, and the occurrence of unexpected events, all which have the potential to have an impact on royalties payable in respect of our international operations in Libya and Syria.

## Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over the company's international operations. If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. Additionally, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

## Operating Hazards and Other Uncertainties

Each of our principal operating businesses – Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing – demand significant levels of investment and therefore carry economic risks and opportunities. Generally, our operations are subject to hazards and risks such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts, power outages and oil spills, any of which can cause personal injury, death, damage to property, information technology systems and related data and control systems, equipment, and the environment, as well as interrupt operations.

In addition, all of our operations are subject to all of the risks connected with transporting, processing and storing crude oil, natural gas and other related products. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels in our crude oil and natural gas business. Risks associated with access to skilled labour to support our operations in a safe and effective manner are also discussed in "Labour and Materials Supply" below.

At Oil Sands, mining oil sands and producing bitumen through in situ methods, extracting bitumen from the oil sands, and upgrading bitumen into synthetic crude oil and other products involve particular risks and uncertainties. Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions at Oil Sands can cause reduced production during the winter season and, in some situations, can result in higher costs. While there are virtually no finding costs associated with oil sands resources, the costs to delineate the resources, the costs associated with production, including mine development and drilling wells for in situ operations, and the costs associated with upgrading bitumen into synthetic crude oil can entail significant capital outlays. The costs associated with oil sands production are largely fixed in the short term. As a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with our Natural Gas operations, including all of the risks normally associated with drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, fires, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

Our International and Offshore operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes or other extreme weather conditions, and the drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling, operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Damage to the environment, particularly through oil spillage in our operations or extensive uncontrolled fires or death, could result from these operations.

Our Refining and Marketing business is subject to all of the risks normally inherent in the operation of a refinery, terminals, pipelines and other distribution facilities as well as service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock, oil spills or other incidents.

We are also subject to operational risks such as sabotage, terrorism, trespass, related damage to remote facilities, theft and malicious software or network attacks.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Although we maintain a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses beyond the scope of insurance could have a material adverse effect on our business, financial condition, results of operations and cash flow. In 1990, 2003 and 2005, we formed three self-insurance entities to provide additional business interruption coverage for potential losses. In the first quarter of 2010, these three entities were merged into one single entity.

### Project Delivery

There are certain risks associated with the execution of our major projects. These risks include: our ability to obtain the necessary environmental and other regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; our ability to finance growth if commodity prices were to decline and stay at low levels for an extended period; risks relating to restarting projects placed in safe mode, including increased capital costs; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving targets and objectives. Management believes the execution of major projects presents issues that require prudent risk management. There are also risks associated with project cost estimates provided by us. Some cost estimates are provided at the conceptual stage of projects and prior to commencement or completion of the final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs can vary from estimates, and these differences can be material. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Our Oil Sands business is susceptible to loss of production due to the interdependence of its component systems. Through growth projects, we expect to further mitigate adverse impacts of interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, we added a second upgrader, which provides us with the flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other. Our inability to sufficiently manage these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

### Reputational Risk

The public perception of oil companies and their operations, including GHG emissions related to current and planned projects in the oil sands area of Alberta, may pose issues related to development and operating approvals or market access for products, which may directly or indirectly impair profitability.

### Permit Approval

Before proceeding with most major projects, including significant changes to existing operations, we must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions, including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flow. Such regulations may be changed from time-to-time in response to numerous factors, including economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase our costs and have a material adverse effect on our business, financial condition, results of operations and cash flow.

### Labour and Materials Supply

The successful operation of the company's business and ability to expand its operations will depend upon the availability of, and competition for, skilled labour and materials supply. The demand for and supply of skilled labour remains limited, even in uncertain economic conditions, and there is a risk that we may have difficulty sourcing the required labour for current and future operations. As well, materials may be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in "Project Delivery" above.

### Suncor's Governance Process

Suncor believes that the responsibility for managing climate change related issues should be a shared responsibility across the company. A comprehensive "roles and responsibilities" matrix has been developed as part of Suncor's GHG management program.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors reviews Suncor's effectiveness in meeting its obligations pertaining to environment, health and safety (EHS). The committee also reviews the effectiveness with which Suncor establishes appropriate environment, health and safety policies, including GHG performance and emission reduction plans given legal, industry and community standards. Management systems are maintained by the committee to implement such policies and ensure compliance with them.

Suncor's Chief Operating Officer holds top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units' EHS Managers and selected internal technical representatives are responsible for the stewardship of the GHG management system. The GHG strategy team is responsible for developing company-wide strategies and operational goals and assessing sustainability progress, including GHG intensity reduction, across all areas of our business.

In advance of clear regulations in all jurisdictions that we operate, Suncor will continue to be guided by the seven-point climate change action plan we first adopted in 1997, which calls on us to:

- Manage our own GHG emissions;
- Develop renewable sources of energy;

- Invest in environmental and economic research through joint venture initiatives with other industry groups, and through internal initiatives focused on our core business;
- Use domestic and international offsets;
- Collaborate on policy development;
- Educate employees and the public; and
- Measure and report our progress;

Suncor remains committed to reducing overall greenhouse gas emission intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation, and reducing air emissions. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities both internally, as well as through joint venture initiatives, such as our role in the Oil Sands Leadership Initiative, with other like-minded energy companies.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets and liabilities, disclosures of contingencies and revenues and expenses. These estimates and assumptions are subject to change based on experience and new information. Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's Consolidated Financial Statements.

### Asset Retirement Obligations (ARO)

Suncor is required to recognize a liability for the future retirement obligations associated with the legal requirement to retire tangible long-lived assets such as tailings ponds, producing well sites, and crude oil and natural gas processing plants. An ARO liability is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying Suncor's total ARO amount. These individual assumptions can be subject to change based on experience.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through DD&A over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the company's weighted average credit-adjusted risk-free interest rate, which is currently 5.4% (2009 – 6.2%). In subsequent periods, the ARO is adjusted for the passage of time, adjusted to estimated costs to settle the liability, and changes to the timing of the underlying future cash flows. These changes to estimates impact both the DD&A on the retirement cost and the accretion expense on the ARO reported in the Consolidated Statements of Earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains and losses on the final settlement of the ARO.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company and third-party reviews of ARO during 2010, Suncor decreased the estimated undiscounted total obligation to $7.4 billion from the previous estimate of $8.3 billion. The decrease was primarily due to significant disposals in the International and Offshore segment and the Natural Gas segment, where the ARO obligation was assumed by the purchasing entity. In addition, the Oil Sands segment decreased its obligation mainly due to the 2010 ARO obligation being calculated using the company's proprietary TRO$_{TM}$ tailings management process, compared to a combination of methods in 2009. The company anticipates that TRO$_{TM}$ will allow the company to accelerate the pace of reclamation and reduce costs in the long term. The estimated discounted total obligation at December 31, 2010, was

$2.4 billion, compared to $3.2 billion at December 31, 2009.

### Employee Future Benefits

Suncor provides a range of benefits to employees and retired employees, including pensions and other post-retirement benefits. The determination of obligations under these benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of considering actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in our Consolidated Statements of Earnings. The accrued net benefit liability is reported as part of accrued liabilities and other.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan's asset portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used.

### Successful Efforts Accounting

Suncor follows the successful efforts method for exploration and production development activities related to conventional oil and gas producing properties.

The application of the successful efforts method of accounting requires management apply judgment to determine, among other things, the designation of activities as developmental or exploratory. All development costs are capitalized. Costs of drilling exploratory wells are initially capitalized, pending the evaluation of commercially recoverable reserves. The results of an exploratory drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the drilling costs of the exploratory well are charged to exploration expense.

### Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows with the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves, production quantities, future commodity prices, operating costs and future development costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value. Where properties are assessed by management to be fully or partially impaired, the book value of the properties is reduced to fair value, with the difference reported as part of DD&A expense.

Assets held for sale are also required to undergo an impairment test and are valued at the lower of carrying value and net recoverable value, which often equates to discounted cash flow estimates, or expected sale proceeds when an offer has been received.

### Oil and Gas Reserves

Our oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty and interpretation. Reserves estimates can be revised either upwards or downwards based on updated information such as future drilling, testing and production levels. Reserves estimates, although not reported as part of the company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments.

For December 31, 2010, reserves estimates for our Syria assets were reduced to reflect only those parts of the Ash Shaer field with existing well control, and to reflect interpreted higher porosity cut-offs in a significant secondary zone.

### Income Taxes

The company follows the liability method of accounting for income taxes, whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the company's current and future income tax provisions, future income tax assets and liabilities, and net earnings.

### Contingencies

The company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the company as at December 31, 2010. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the company's contingent liabilities in the future.

### Purchase Price Allocation

The 2009 merger with Petro-Canada was treated as a business acquisition and accounted for by the purchase method of accounting. Under this method, the purchase price was allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. Management finalized the purchase price allocation during the second quarter of 2010 and did not make any amendments to the preliminary allocation.

## CHANGES IN ACCOUNTING POLICIES

### International Financial Reporting Standards (IFRS)

#### IFRS Conversion Project

The company's IFRS conversion project continues to be on target to release first quarter 2011 IFRS financial statements. The following is a status update of the IFRS conversion project.

#### IFRS Financial Statement Preparation

First quarter and annual 2011 IFRS financial statements and disclosures have been drafted and provided to senior management and the company's external auditor for review. The first quarter 2011 financial statements and disclosures will be presented to the IFRS Steering Committee and Audit Committee in the first quarter of 2011.

#### IFRS Training

IFRS training and communication sessions continued for key individuals, senior management and the Audit Committee.

#### IFRS Infrastructure

Significant IFRS information technology activities were completed during the fourth quarter, including recording of IFRS entries for the first three quarters of 2010 into the company's dual reporting system. Testing of the 2011 conversion plan was completed in 2010. Comprehensive training for implementation of business process changes will occur in the first quarter of 2011 with implementation targeted for the second quarter of 2011.

#### IFRS Control Environment

The company has completed testing of internal control documentation related to the preparation of the 2010 IFRS financial statements. Review of internal and disclosure controls over financial reporting for 2011 will be completed in the first quarter of 2011. No material changes are expected to the controls over financial reporting.

#### IFRS Expected Accounting Policy Impacts

In addition to the policy changes outlined below, the company continues to monitor IFRS developments. Accounting policies selected for the draft IFRS opening Consolidated Balance Sheets remain subject to change. The company is not required to finalize IFRS accounting policies prior to the release of the first annual audited IFRS financial statements for the year ending December 31, 2011.

The following discussion provides further details on the impacts of accounting policy choices and changes on the draft IFRS opening Consolidated Balance Sheets, including exemptions available under IFRS 1 *First-Time Adoption of International Financial Reporting Standards*. IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS.

- **Property, Plant and Equipment (PP&E)**

  Although the principles of componentization and derecognition exist under both IFRS and Canadian GAAP, the standards differ in certain respects. Under

IFRS, the basis that the company has used to apply these principles will be at a lower component level, resulting in a decrease to the January 1, 2010 PP&E balance of approximately $110 million.

Upon adoption of IFRS, Suncor will reclassify approximately $4.5 billion of Exploration and Evaluation (E&E) assets from PP&E to E&E. E&E assets include unproven land, exploratory drilling and exploratory project costs.

IFRS 1 contains an exemption where an entity may elect to use fair value as its deemed cost for assets at the date of transition. The company elected to use this exemption for certain Natural Gas and Refining and Marketing assets. As a result, approximately $900 million of asset value was derecognized and charged to retained earnings.

- **Provisions, Contingent Liabilities and Contingent Assets**

  The company is planning to utilize the IFRS 1 exemption permitting the recalculation of the ARO cost included in PP&E as at January 1, 2010, using a simplified retrospective calculation. The company has made a preliminary decision to discount the estimated fair value of its ARO using the credit-adjusted risk-free rate. However, the discount rate under IFRS at transition differs from the credit-adjusted risk-free rate utilized for Canadian GAAP. These differences have resulted in an increase of approximately $300 million to the ARO liability, a decrease of approximately $700 million to the related PP&E assets and a corresponding reduction to retained earnings at January 1, 2010. If the company elected to use a risk-free discount rate the adjustment to opening retained earnings would be significantly higher.

- **Share-Based Payments**

  IFRS 2 *Share-based Payment* requires that cash-settled share-based payments be measured (both initially and at each reporting period) at the fair values of the awards. Canadian GAAP requires that such awards be measured based on the intrinsic values of the awards. This difference has resulted in an increase to the company's share-based payments liability of approximately $120 million at January 1, 2010 with a corresponding reduction to retained earnings. In addition, a change to the graded vesting method for stock-based compensation has resulted in a $10 million increase in the contributed surplus balance at January 1, 2010. The company will elect to use the IFRS 1 exemption under which IFRS 2 is not required to be applied to equity-settled instruments.

- **Employee Future Benefits**

  The company has opted to elect to use the IFRS 1 exemption to recognize immediately in retained earnings all cumulative actuarial gains and losses existing at the date of transition (approximately $60 million). This impact will be partially offset by approximately $30 million for a change to the attribution method for post-retirement benefits and recognition of unamortized past service costs not fully vested.

- **Foreign Exchange**

  First-time adopters of IFRS can elect to deem cumulative translation differences to be zero at the date of transition. The company has elected to take this IFRS 1 exemption which has resulted in a reclassification of approximately $250 million from other reserves (previously termed "accumulated other comprehensive income") to retained earnings.

- **Income Taxes**

  In transitioning to IFRS, the company's future tax liability is impacted by the tax effects resulting from the IFRS changes discussed above. The company expects to recognize a decrease in the deferred tax liability of approximately $600 million at January 1, 2010.

- **Business Combinations and Joint Ventures**

  Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles as permitted by IFRS 1.

Additional IFRS accounting policy choices and changes have not had a material impact on the IFRS opening Consolidated Balance Sheets and will continue to be monitored throughout 2011.

### IFRS Quarterly Earnings Impacts

The company is currently finalizing the 2010 quarterly earnings impacts, but expects earnings to be impacted by:

- Lower depreciation expense as a result of opening Balance Sheet impairments, derecognition of assets and a reduction to the ARO asset;
- Lower accretion expense due to a decrease in the discounted rate;
- Restated share-based compensation expense due to remeasurement of cash-settled awards at fair value for each reporting period;
- Reclassifications for assets held for sale, to the respective financial statement line items, previously reported as discontinued operations under Canadian

GAAP. Dispositions did not meet the definition of discontinued operations under IFRS, resulting in additional reclassifications on the Consolidated Statements of Comprehensive Income.

## CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2010, our chief executive officer and chief financial officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2010, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during 2010 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2010, based on that evaluation, the company's internal controls were found to be operating free of any material weaknesses.

The company continues to integrate legacy Petro-Canada's historical internal control over financial reporting with Suncor's internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods, but it is not yet known whether these changes will materially affect internal control over financial reporting. This integration process is expected to be substantially completed by the end of 2011.

The effectiveness of our internal control over financial reporting as at December 31, 2010 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2010.

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those options determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

## OUTLOOK

Detailed guidance on 2011 capital expenditures and production outlook can be found in Suncor's December 17, 2010 press release and on the Suncor website at www.suncor.com/guidance, which is not incorporated by reference herein.

## NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures referred to in this MD&A, namely operating earnings, cash flow from operations, return on capital employed and Oil Sands cash operating costs, are not prescribed by Canadian GAAP.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses this information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

### Operating Earnings

Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that management believes are not indicative of operating performance and that reduce the comparability of the underlying financial performance between periods. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

## Return on Capital Employed (ROCE)

ROCE is included because management uses this information to analyze operating performance, leverage and liquidity.

| For the year ended December 31 ($ millions, except ROCE) | | **2010** | 2009 | 2008 |
|---|---|---|---|---|
| **Adjusted net earnings** | | | | |
| Net earnings | | **3 571** | 1 146 | 2 137 |
| Add: after-tax financing expense (income) | | **(80)** | (509) | 852 |
| | A | **3 491** | 637 | 2 989 |
| **Capital employed – beginning of year** | | | | |
| Short-term and long-term debt, less cash and cash equivalents | | **13 377** | 7 226 | 3 248 |
| Shareholders' equity | | **34 111** | 14 523 | 11 896 |
| | B | **47 488** | 21 749 | 15 144 |
| **Capital employed – end of year** | | | | |
| Short-term and long-term debt, less cash and cash equivalents | | **11 112** | 13 377 | 7 226 |
| Shareholders' equity | | **36 721** | 34 111 | 14 523 |
| | C | **47 833** | 47 488 | 21 749 |
| **Average capital employed** (1) | D | **47 519** | 35 128 | 18 447 |
| **Average capitalized costs related to major projects in progress** | E | **12 889** | 10 655 | 5 149 |
| **ROCE (%)** | A/(D-E) | **10.1** | 2.6 | 22.5 |

(1) Average capital employed for 2008 is calculated on a simple-average basis (B+C)/2. For 2009 and 2010, as a result of the significant capital employed that was acquired during the year due to the merger with Petro-Canada, average capital employed is now calculated on a monthly weighted average basis.

## Cash Flow from Operations

Cash flow from operations is expressed before changes in non-cash working capital.

| Year ended December 31 ($ millions) | Oil Sands 2010 | Oil Sands 2009 | Oil Sands 2008 | Natural Gas 2010 | Natural Gas 2009 | Natural Gas 2008 | International and Offshore 2010 | International and Offshore 2009 | International and Offshore 2008 |
|---|---|---|---|---|---|---|---|---|---|
| Net earnings (loss) from continuing operations | **1 492** | 557 | 2 875 | **(277)** | (185) | 34 | **1 114** | 323 | — |
| Adjustments for: | | | | | | | | | |
| Depreciation, depletion and amortization | **1 318** | 922 | 580 | **773** | 287 | 137 | **1 172** | 299 | — |
| Future income taxes | **484** | (643) | 535 | **(96)** | (47) | (7) | **108** | 48 | — |
| Accretion of asset retirement obligations | **120** | 111 | 55 | **29** | 14 | 4 | **27** | 10 | — |
| Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt | **—** | — | — | **—** | — | — | **—** | — | — |
| Change in fair value of derivative contracts | **(316)** | 960 | (590) | **—** | — | — | **—** | — | — |
| Loss (gain) on disposal of assets | **14** | 70 | 36 | **(132)** | (20) | (22) | **2** | — | — |
| Stock-based compensation | **48** | 90 | 54 | **12** | 19 | 4 | **18** | 12 | — |
| Gain on effective settlement of pre-existing contract with Petro-Canada | **—** | (438) | — | **—** | — | — | **—** | — | — |
| Other | **(391)** | (378) | (38) | **(6)** | (11) | (13) | **8** | 40 | — |
| Exploration expenses | **—** | — | — | **17** | 120 | 61 | **63** | 6 | — |
| **Cash flow from (used in) operations from continuing operations** | **2 769** | 1 251 | 3 507 | **320** | 177 | 198 | **2 512** | 738 | — |
| **Cash flow provided by discontinued operations** | **—** | — | — | **125** | 152 | 169 | **367** | 213 | — |
| **Total cash flow from (used in) operations** | **2 769** | 1 251 | 3 507 | **445** | 329 | 367 | **2 879** | 951 | — |

| Year ended December 31 ($ millions) | Refining and Marketing 2010 | Refining and Marketing 2009 | Refining and Marketing 2008 | Corporate, Energy Trading and Eliminations 2010 | Corporate, Energy Trading and Eliminations 2009 | Corporate, Energy Trading and Eliminations 2008 | Total 2010 | Total 2009 | Total 2008 |
|---|---|---|---|---|---|---|---|---|---|
| Net earnings (loss) from continuing operations | **801** | 407 | (22) | **(442)** | 104 | (805) | **2 688** | 1 206 | 2 082 |
| Adjustments for: | | | | | | | | | |
| Depreciation, depletion and amortization | **475** | 317 | 198 | **75** | 35 | 46 | **3 813** | 1 860 | 961 |
| Future income taxes | **261** | 99 | (14) | **(202)** | (85) | (55) | **555** | (628) | 459 |
| Accretion of asset retirement obligations | **2** | 1 | 1 | **—** | — | — | **178** | 136 | 60 |
| Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt | **—** | — | — | **(426)** | (858) | 919 | **(426)** | (858) | 919 |
| Change in fair value of derivative contracts | **—** | (14) | 27 | **31** | 34 | (75) | **(285)** | 980 | (638) |
| Loss (gain) on disposal of assets | **(30)** | 16 | 6 | **39** | — | (7) | **(107)** | 66 | 13 |
| Stock-based compensation | **40** | 35 | 16 | **(4)** | 106 | (96) | **114** | 262 | (22) |
| Gain on effective settlement of pre-existing contract with Petro-Canada | **—** | — | — | **—** | — | — | **—** | (438) | — |
| Other | **(13)** | 60 | 8 | **(44)** | 11 | 36 | **(446)** | (278) | (7) |
| Exploration expenses | **—** | — | — | **—** | — | — | **80** | 126 | 61 |
| **Cash flow from (used in) operations from continuing operations** | **1 536** | 921 | 220 | **(973)** | (653) | (37) | **6 164** | 2 434 | 3 888 |
| **Cash flow provided by discontinued operations** | **—** | — | — | **—** | — | — | **492** | 365 | 169 |
| **Total cash flow from (used in) operations** | **1 536** | 921 | 220 | **(973)** | (653) | (37) | **6 656** | 2 799 | 4 057 |

## LEGAL ADVISORY – FORWARD LOOKING INFORMATION

*This Management's Discussion and Analysis contains certain forward-looking statements and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends including expectations and assumptions concerning the accuracy of reserve and resource estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", and similar expressions. Forward-looking statements in this Management's Discussion and Analysis include references to:*

- *Our plan in 2011 to direct approximately $2.8 billion towards a range of oil sands growth projects, as part of our overall $6.7 billion 2011 capital-spending plan;*
- *Suncor's strategic partnership with Total, which is expected to close in the first quarter of 2011, and the terms of same, including the consideration to be received by Suncor (approximately $1.75 billion) and the expected assets to be exchanged between the parties: Total will acquire a 49% interest in Suncor's Voyageur Upgrader, and an additional 19.2% in the Fort Hills project; and Suncor will acquire a 36.75% interest in the Joslyn project;*
- *Timelines and plans for the Voyageur Upgrader, the Fort Hills mine and the Joslyn mine;*
- *Suncor's sale of certain of its U.K. offshore assets, and the expected completion of same during the first half of 2011;*
- *Suncor's proprietary $TRO_{TM}$ tailings reclamation, which is expected to significantly reduce pond reclamation time, and the plan to have it completed by the end of 2012 at a cumulative capital cost in excess of $1.0 billion;*
- *Oil Sands' six-week planned turnaround scheduled for Upgrader 2 in the second quarter of 2011 and the expectation that production volumes will be reduced by approximately 215,000 bpd over the duration of the turnaround;*
- *Fifteen-week dockside maintenance program at Terra Nova planned for 2011, where production volumes are anticipated to be reduced by approximately 25,000 bpd over the duration of the turnaround;*
- *Turnarounds, including the three-week routine turnaround planned at White Rose, the one-week planned shutdown at Buzzard and planned major turnarounds for the Sarnia, Edmonton and Commerce City refineries in 2011;*
- *Planned expansions for Firebag Stage 3, where production is targeted to begin late in the second quarter of 2011, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter;*
- *Planned expansion for Firebag Stage 4, where production is targeted to begin late in the first quarter of 2013, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter;*
- *Suncor's MNU project, which is expected to be completed by the end of 2011;*
- *Expected tie-in during the first quarter of 2011 of Suncor's drilling programs in the Ferrier area located in central Alberta and the Pouce Coupe area in western Alberta;*
- *Planned drilling at North Amethyst and the White Rose Extensions;*
- *Expected production for the first phase of the West White Rose portion of the White Rose Extension (first oil expected by mid-2011), the Hibernia South Extension project (early production from the unit is expected in mid-2011) and Hebron (first oil expected in 2017);*
- *Projected completion by the end of 2011 of Suncor's Wintering Hills wind power project, and the expectation that the project will generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of carbon dioxide per year;*
- *Anticipated completion of the Kent Breeze wind power project (mid-2011);*
- *Suncor's management's belief that Suncor will have the capital resources to fund its planned 2011 capital spending program and to meet current and long-term working capital requirements and that if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates; and*
- *Expected effects of changeover to IFRS.*

*This Management's Discussion and Analysis also contains forward-looking statements and information concerning the anticipated completion and timing of the proposed transaction with Total E&P Canada Ltd. and our transaction to sell our non-core U.K. assets. Suncor has provided these anticipated times in reliance on certain assumptions that we believe are reasonable at this time,* *including assumptions as to the timing of receipt of the necessary regulatory, court and other third-party approvals, and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in the ability to secure necessary regulatory or other third party approvals or the need for additional time to satisfy the conditions to the completion of the transaction. The transaction may not close as scheduled or at all. As a result of the foregoing, readers should not place undue reliance on the forward-looking statements and information contained in this Management's Discussion and Analysis concerning these items.*

*Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and information and readers are cautioned not to place undue reliance on them.*

*The financial and operating performance of the company's business segments, including Oil Sands, Natural Gas, International and Offshore and Refining and Marketing, may be affected by a number of factors, including, but not limited to, the following:*

*Factors that affect our Oil Sands business:*

- *Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.*
- *Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment.*
- *Bitumen supply. The unavailability of third party bitumen, poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in situ reservoir and equipment performance could impact production targets.*
- *Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.*
- *Our ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through strategies such as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.*
- *Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.*
- *Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.*
- *Volatility in light/heavy and sweet/sour crude oil differentials.*
- *Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.*
- *Changes to royalty and tax legislation and related agreements that could impact our business (including our current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation). While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and lower rates of return on existing investments.*
- *Our relationship with our trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.*

*Factors that affect our Natural Gas business:*

- *Volatility in natural gas prices.*
- *Risk associated with a depressed market for asset sales, leading to losses on disposition.*
- *The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.*
- *Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.*

*Factors that affect our International and Offshore business:*

- *Risks and uncertainties associated with international and offshore operations normally inherent in such activities such as drilling, operation and development of such properties including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs,* *equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, pollution and other environmental risks.*

- *Performance after completion of maintenance is not predictable and can significantly impact production rates.*
- *Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities.*

*These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.*

- *Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in exploration, operations or abandonment activities.*
- *Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by production quotas.*

*Factors that affect our Refining and Marketing business:*

- *Production reliability risk. Our ability to reliably operate our refining and marketing facilities in order to meet production targets.*
- *Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.*
- *There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.*
- *Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia refinery, our Commerce City refinery, our Montreal refinery, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have an adverse effect on our business, financial condition, results of operations and cash flow.*

*Additional Risks, Uncertainties and Other Factors*

*Additional risks, uncertainties and other factors that could influence the actual results of all of Suncor's business segments include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange; volatility in natural gas and liquids prices is not predictable and can significantly impact revenues; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Suncor's operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us (including in respect of any planned divestitures); risks and uncertainties associated with the ability of closing conditions to be met with respect to the sale of any of Suncor's assets, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of Suncor and Petro-Canada after the merger;*

*and incorrect assessments of the values of Petro-Canada. The foregoing important factors are not exhaustive.*

*Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this Management's Discussion and Analysis, including under the heading "Risk Factors" and its Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.*

## MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. and all related financial information contained in the Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of the company's financial reporting.

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited, to conduct independent evaluations of the company's oil and gas reserves and resources.

The Audit Committee of the Board of Directors, currently composed of six independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditor to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditor any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resource estimates, and recommend their approval to the Board of Directors. The internal auditors and the external auditor, PricewaterhouseCoopers LLP, have unrestricted access to the company, the Audit Committee and the Board of Directors.

Rick George

**Richard L. George**
President and
Chief Executive Officer

**Bart Demosky**
Chief Financial Officer

*February 24 2011*

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the U.S. Securities Exchange Act of 1934):

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.
2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control — Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.
3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2010, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2010. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
4. The effectiveness of the company's internal control over financial reporting as at December 31, 2010 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.

Rich George

**Richard L. George**
President and
Chief Executive Officer

**Bart Demosky**
Chief Financial Officer

*February 24, 2011*

# INDEPENDENT AUDITOR'S REPORT

## TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of Suncor Energy Inc.'s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

### REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Suncor Energy Inc. ("the company"), which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings, comprehensive income, changes in shareholders' equity and of cash flows for each of the years in the three year period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

#### Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

#### Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

#### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

### REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the company's internal control over financial reporting as at December 31, 2010, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

#### Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting.

#### Auditor's responsibility

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company

Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

**Definition of internal control over financial reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with Canadian generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

**Inherent limitations**

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

**Opinion**

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

**PricewaterhouseCoopers LLP**
Chartered Accountants
Calgary, Alberta

*February 24, 2011*

## CONSOLIDATED STATEMENTS OF EARNINGS

| For the years ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Revenues** | | | |
| Operating revenues (note 21) | **33 198** | 17 977 | 17 920 |
| Less: Royalties (note 4) | **(1 937)** | (1 150) | (822) |
| Operating revenues (net of royalties) | **31 261** | 16 827 | 17 098 |
| Energy supply and trading activities (notes 7 and 21) | **2 700** | 7 577 | 11 320 |
| Interest and other income (notes 3 and 5) | **389** | 444 | 28 |
| | **34 350** | 24 848 | 28 446 |
| **Expenses** | | | |
| Purchases of crude oil and products | **14 911** | 7 388 | 7 606 |
| Operating, selling and general (note 20) | **7 810** | 6 430 | 4 146 |
| Energy supply and trading activities (notes 7 and 21) | **2 598** | 7 381 | 11 323 |
| Transportation | **656** | 396 | 240 |
| Depreciation, depletion and amortization (note 15) | **3 813** | 1 860 | 961 |
| Accretion of asset retirement obligations | **178** | 136 | 60 |
| Exploration | **197** | 209 | 90 |
| Loss (gain) on disposal of assets | **(107)** | 66 | 13 |
| Project start-up costs | **77** | 51 | 35 |
| Financing expenses (income) (note 8) | **(30)** | (488) | 917 |
| | **30 103** | 23 429 | 25 391 |
| **Earnings before Income Taxes** | **4 247** | 1 419 | 3 055 |
| **Provisions for (Recovery of) Income Taxes** (note 9) | | | |
| Current | **1 004** | 841 | 514 |
| Future | **555** | (628) | 459 |
| | **1 559** | 213 | 973 |
| **Net Earnings from Continuing Operations** | **2 688** | 1 206 | 2 082 |
| **Net Earnings (Loss) from Discontinued Operations** (note 6) | **883** | (60) | 55 |
| **Net Earnings** | **3 571** | 1 146 | 2 137 |
| **Net Earnings from Continuing Operations per Common Share** (dollars) | | | |
| Basic | **1.72** | 1.01 | 2.23 |
| Diluted | **1.71** | 1.00 | 2.20 |
| **Net Earnings per Common Share** (dollars) (note 10) | | | |
| Basic | **2.29** | 0.96 | 2.29 |
| Diluted | **2.27** | 0.95 | 2.26 |
| Cash Dividends per Common Share (dollars) | **0.40** | 0.30 | 0.20 |

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| For the years ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Net earnings | **3 571** | 1 146 | 2 137 |
| Other comprehensive income (loss), net of tax | | | |
| Change in foreign currency translation adjustment | **(503)** | (332) | 350 |
| Reclassification to net earnings | **53** | — | — |
| Gain (loss) on derivative contracts designated as cash flow hedges | **—** | — | (7) |
| Reclassification to net earnings | **(1)** | 2 | 7 |
| **Comprehensive Income** | **3 120** | 816 | 2 487 |

See accompanying notes to the consolidated financial statements.

## CONSOLIDATED BALANCE SHEETS

| As at December 31 ($ millions) | **2010** | 2009 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents (note 11) | **1 077** | 505 |
| Accounts receivable | **5 253** | 3 703 |
| Inventories (note 13) | **3 141** | 2 947 |
| Income taxes receivable | **734** | 587 |
| Future income taxes (note 9) | **210** | 332 |
| Assets of discontinued operations (note 6) | **98** | 257 |
| Total current assets | **10 513** | 8 331 |
| Property, plant and equipment, net (note 14) | **55 290** | 54 198 |
| Other assets (note 16) | **451** | 491 |
| Goodwill (note 2) | **3 201** | 3 201 |
| Future income taxes (note 9) | **56** | 193 |
| Assets of discontinued operations (note 6) | **658** | 3 332 |
| Total assets | **70 169** | 69 746 |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Short-term debt | **2** | 2 |
| Current portion of long-term debt | **518** | 25 |
| Accounts payable and accrued liabilities (note 18) | **6 942** | 6 307 |
| Income taxes payable | **929** | 1 254 |
| Future income taxes (note 9) | **37** | 18 |
| Liabilities of discontinued operations (note 6) | **98** | 242 |
| Total current liabilities | **8 526** | 7 848 |
| Long-term debt (note 17) | **11 669** | 13 855 |
| Accrued liabilities and other (note 18) | **4 154** | 4 372 |
| Future income taxes (note 9) | **8 615** | 8 367 |
| Liabilities of discontinued operations (note 6) | **484** | 1 193 |
| Shareholders' equity (see below) | **36 721** | 34 111 |
| Total liabilities and shareholders' equity | **70 169** | 69 746 |

Commitments and contingencies (note 24)

## SHAREHOLDERS' EQUITY

| As at December 31 ($ millions) | **Number (thousands)** | **2010** | Number (thousands) | 2009 |
|---|---|---|---|---|
| Share capital (note 20) | **1 565 489** | **20 188** | 1 559 778 | 20 053 |
| Contributed surplus | | **505** | | 526 |
| Accumulated other comprehensive income (loss) (note 22) | | **(684)** | | (233) |
| Retained earnings | | **16 712** | | 13 765 |
| Total shareholders' equity | | **36 721** | | 34 111 |

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

**Richard L. George,**
Director

**Brian A. Canfield,**
Director

*February 24, 2011*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| For the years ended December 31 ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net earnings from continuing operations | **2 688** | 1 206 | 2 082 |
| Adjustments for: | | | |
| Depreciation, depletion and amortization | **3 813** | 1 860 | 961 |
| Future income taxes | **555** | (628) | 459 |
| Accretion of asset retirement obligations | **178** | 136 | 60 |
| Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt (note 8) | **(426)** | (858) | 919 |
| Change in fair value of derivative contracts (note 21) | **(285)** | 980 | (638) |
| Loss (gain) on disposal of assets | **(107)** | 66 | 13 |
| Stock-based compensation | **114** | 262 | (22) |
| Gain on effective settlement of pre-existing contract with Petro-Canada (note 3) | **—** | (438) | — |
| Other | **(446)** | (278) | (7) |
| Exploration expenses | **80** | 126 | 61 |
| Change in non-cash working capital related to operating activities (note 12) | **(1 230)** | (237) | 403 |
| Cash flow provided by continuing operations | **4 934** | 2 197 | 4 291 |
| Cash flow provided by discontinued operations | **552** | 378 | 171 |
| Cash flow from operating activities | **5 486** | 2 575 | 4 462 |
| **Investing Activities** | | | |
| Capital and exploration expenditures | **(5 833)** | (4 020) | (7 947) |
| Other investments | **3** | (9) | (18) |
| Cash acquired through business combination (note 3) | **—** | 248 | — |
| Proceeds from disposal of assets | **307** | 148 | 33 |
| Change in non-cash working capital related to investing activities (note 12) | **(196)** | (791) | 415 |
| Cash flow used in continuing investing activities | **(5 719)** | (4 424) | (7 517) |
| Cash flow provided by (used in) discontinued investing activities | **2 607** | (247) | (73) |
| **Cash flow used in investing activities** | **(3 112)** | (4 671) | (7 590) |
| **Financing Activities** | | | |
| Change in short-term debt | **—** | — | (1) |
| Net proceeds from issuance of long-term debt | **—** | — | 2 704 |
| Change in revolving-term debt | **(1 257)** | 2 325 | 422 |
| Issuance of common shares under stock option plan | **81** | 41 | 190 |
| Dividends paid on common shares | **(611)** | (401) | (180) |
| Cash flow provided by (used in) financing activities | **(1 787)** | 1 965 | 3 135 |
| **Increase (Decrease) in Cash and Cash Equivalents** | **587** | (131) | 7 |
| **Effect of Foreign Exchange on Cash and Cash Equivalents** | **(15)** | (24) | 84 |
| **Cash and Cash Equivalents at Beginning of Period** | **505** | 660 | 569 |
| **Cash and Cash Equivalents at End of Period** | **1 077** | 505 | 660 |

See accompanying notes to the consolidated financial statements.

## CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

| For the years ended December 31 ($ millions) | Share Capital | Contributed Surplus | Accumulated Other Comprehensive Income (Loss) | Retained Earnings |
|---|---|---|---|---|
| **At December 31, 2007** | 881 | 194 | (253) | 11 074 |
| Net earnings | — | — | — | 2 137 |
| Dividends paid on common shares | — | — | — | (180) |
| Issued for cash under stock option plans | 226 | (36) | — | — |
| Issued under dividend reinvestment plan | 6 | — | — | (6) |
| Stock-based compensation expense | — | 120 | — | — |
| Income tax benefit of stock option deductions in the U.S. | — | 10 | — | — |
| Other comprehensive income (loss) | — | — | 350 | — |
| **At December 31, 2008** | 1 113 | 288 | 97 | 13 025 |
| Net earnings | — | — | — | 1 146 |
| Dividends paid on common shares | — | — | — | (401) |
| Issued for cash under stock option plans | 57 | (16) | — | — |
| Issued under dividend reinvestment plan | 5 | — | — | (5) |
| Stock-based compensation expense | — | 103 | — | — |
| Issued for Petro-Canada acquisition (note 3) | 18 878 | — | — | — |
| Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 3) | — | 147 | — | — |
| Income tax benefit of stock option deduction in the U.S. | — | 4 | — | — |
| Other comprehensive income (loss) | — | — | (330) | — |
| **At December 31, 2009** | **20 053** | **526** | **(233)** | **13 765** |
| Net earnings | **—** | **—** | **—** | **3 571** |
| Dividends paid on common shares | **—** | **—** | **—** | **(611)** |
| Issued for cash under stock option plans | **122** | **(34)** | **—** | **—** |
| Issued under dividend reinvestment plan | **13** | **—** | **—** | **(13)** |
| Stock-based compensation expense | **—** | **13** | **—** | **—** |
| Other comprehensive income (loss) | **—** | **—** | **(451)** | **—** |
| **At December 31, 2010** | **20 188** | **505** | **(684)** | **16 712** |

See accompanying notes to the consolidated financial statements.

# SUNCOR ENERGY INC.
# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand.

### (a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. The differences that are relevant to the company's financial statements are quantified and explained in note 26.

The consolidated financial statements include the accounts of Suncor and its subsidiaries and the company's proportionate share of the assets, liabilities, equity, revenues, expenses and cash flows of its joint ventures. Subsidiaries are defined as entities in which the company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, employee future benefits, valuation of property, plant and equipment and depreciation, depletion and amortization, purchase price allocation, valuation of goodwill, income taxes, and the estimates of oil and natural gas reserves.

Certain prior period comparative figures have been reclassified to conform to the current period presentation.

### (b) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from crude oil and natural gas production represents Suncor's working interest share before royalty payments to governments and other mineral interest owners. Crude oil and natural gas sold below, or above, the company's working interest share of production, results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues while overlifts are recorded as a payable at market value with a corresponding decrease to revenues.

Intersegment sales of crude oil and natural gas are recorded at market values. Intersegment profits and losses are eliminated on consolidation.

International operations conducted pursuant to exploration and production-sharing agreements (EPSAs) are accounted for based on the company's working interest. Under the EPSAs, the company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the respective government. Cost Recovery Oil, Profit Oil and amounts in respect of all income taxes payable by the company under the laws of the respective country are reported as sales revenue. All other government stakes, other than income taxes, are considered royalty interests.

Physical and financial contracts entered into for trading purposes are considered to be derivative financial instruments, and any changes in fair value are recorded on a net basis in Energy Supply and Trading Activities revenue. Settlement of physical purchase and sales contracts entered into for the company's own usage are recorded on a gross basis in Energy Supply and Trading Activities revenue and Energy Supply and Trading Activities expense.

### (c) Transportation Costs

Transportation costs billed to customers are classified as product revenues with the related transportation costs classified as transportation costs in the Consolidated Statements of Earnings and Comprehensive Income.

### (d) Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. The resulting exchange gains and losses are included in earnings. With the exception of balances pertaining to self-sustaining operations, other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

International operations, refining and marketing operations in the United States, and the company's self-insurance operations, are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in other comprehensive income (loss).

### (e) Income Taxes

Suncor follows the liability method of accounting for income taxes. Future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using enacted or substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

Any investment tax credits received by the company are recorded as an offset to the related expenditures.

### (f) Earnings per Share

Basic earnings per share are calculated by dividing the net earnings by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding those with a cash payment alternative or a tandem stock appreciation right, were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period.

### (g) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less.

### (h) Inventories

Crude oil and refined products inventories, other than those held for trading purposes, are valued at the lower of cost and net realizable value. Cost is determined using the first-in, first-out (FIFO) method, and is calculated as the direct and indirect expenditures incurred to bring an item or product to its existing condition and location.

Inventories of materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy trading operations are carried at fair value less costs to sell and any changes in fair value are recognized as gains or losses within Energy Supply and Trading Activities revenue.

### (i) Investments

Investments in companies over which the company has significant influence are accounted for using the equity method. Other investments are carried at cost.

### (j) Property, Plant and Equipment

***Cost***

Property, plant and equipment are recorded at cost.

The company follows the successful efforts method of accounting for the exploration and development expenditures of oil and gas producing activities. Under successful efforts, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration drilling costs are initially capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploratory drilling costs are expensed as dry hole costs in exploration expense. All other exploration costs, including geological and geophysical costs are expensed as incurred.

Development costs and production facilities, which include the costs of wellhead equipment, development drilling costs, applicable geological and geophysical costs, gas plants and handling facilities, offshore platforms and subsea structures, upgraders, extraction plants and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment are expensed as operating costs.

Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are capitalized. Drilling and related seismic costs for regulatory approved mining areas are capitalized when planned future development timelines do not exceed 10 years.

Planned major maintenance and expenditures that increase capacity or extend the useful lives of assets are capitalized.

***Interest Capitalization***

Interest costs relating to major capital projects in progress are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use or during construction stoppages.

***Leases***

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

***Depreciation, Depletion and Amortization***

Depreciation and depletion of property, plant and equipment for oil and gas producing properties follow successful efforts accounting. Acquisition costs of unproved properties for natural gas and conventional crude are amortized over the lease term until proved reserves are confirmed. Exploration drilling and development costs are depleted over the remaining proved developed reserves. Proved property acquisition costs are depleted over the remaining proved reserves.

Mine and mobile equipment costs are depleted on unit-of-production basis over proved developed reserves or depreciated over periods ranging from two to 20 years. Mining, extraction and upgrading facilities and other property and equipment, including leases in service, are depreciated on a straight-line basis ranging from four to 40 years. Gas plants, central processing facilities of in situ oil sands activities and support facilities and equipment are depreciated on a straight-line basis over their useful lives, which range from three years to 30 years.

Costs associated with significant development projects are not depleted until facilities are substantially complete and ready for their intended productive use.

Depreciation of property, plant and equipment in the refining and marketing operations is on a straight-line basis over the useful lives of assets, which range from three years to 40 years.

Planned major maintenance activities are capitalized and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years.

Depreciation, depletion and amortization rates are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

**(k) Intangible Assets**

Intangible assets, other than goodwill, include acquired customers lists and brand value and are stated at the amount initially recognized, less accumulated amortization. Intangible assets with a finite life are amortized over their expected useful lives which range from five to 10 years, while intangible assets with an indefinite useful life are not subject to amortization. Expected useful lives of intangible assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

**(l) Impairment**

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to Depreciation, Depletion and Amortization expense. In assessing unproven properties for impairment, Suncor considers future plans, the remaining lease terms, and other factors that may indicate impairment.

The carrying values of intangible assets with a finite life are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Intangible assets with an indefinite useful life are assessed for impairment annually, or more frequently as economic events dictate. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the intangible asset's net recoverable value is recognized in Depreciation, Depletion and Amortization expense during the period.

**(m) Goodwill**

Goodwill represents the excess of the purchase price over the fair value of net assets, and mainly relates to the company's acquisition of Petro-Canada. The carrying value of each reporting unit's goodwill is assessed for impairment annually, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

**(n) Asset Retirement Obligations**

A liability, based on current legislation and industry practice, is recognized for future asset retirement obligations (ARO) associated with property, plant and equipment. The fair value of the ARO is recorded on a discounted basis using the company's credit-adjusted risk-free interest rate and is added to the carrying amount of the related asset and amortized consistent with the underlying asset. The liability is accreted until it is expected to settle, with actual expenditures charged against the liability. Changes in the estimated obligation resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the ARO liability and related asset.

**(o) Stock-Based Compensation Plans**

The company's common stock-based compensation plans consist of stock options, stock appreciation rights and share units, and are granted to executives, employees and non-employee directors.

For stock options that give the holder the right to purchase a common share at a predetermined price, the expense is based on the fair values of the option at the time of grant over the estimated vesting periods of the respective options. A corresponding increase is recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. On exercise of options, consideration paid to the company, and the associated contributed surplus, are both credited to share capital.

Stock appreciation rights, share units, and stock options which can be settled for a cash payment, are measured using the intrinsic value method at each period end. A liability and expense are recorded over the vesting period of the options based on the difference of the market price of the underlying shares and the option exercise price. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the stock options is credited to share capital.

For employees eligible to retire prior to the vesting date, the compensation expense is recognized over the shorter period. In instances where an employee is eligible to retire at the time of grant, the full expense is recognized immediately.

Stock-based compensation expense is recorded in Operating, Selling and General expense.

**(p) Employee Future Benefits**

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued proportionately from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments. The excess of the cumulative unamortized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees.

Company contributions to the defined contribution plan are expensed as incurred.

### (q) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. The company has classified each financial instrument into one of the following categories: held-for-trading financial assets and liabilities, loans and receivables, held-to-maturity financial assets, and other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Held-for-trading financial assets and liabilities are subsequently measured at fair value with changes in those fair values recognized in net earnings. Derivative financial instruments are considered held-for-trading unless they are designated as a hedge. Loans and receivables, held-to-maturity financial assets and other financial liabilities are subsequently measured at amortized cost using the effective interest method.

The company classifies cash and cash equivalents as held-for-trading financial assets, accounts receivable as loans and receivables, and accounts payable and accrued liabilities, short-term debt, long-term debt and accrued liabilities and other as other financial liabilities.

The company amortizes transaction costs and premiums or discounts related to issuance of long-term debt using the effective interest method.

#### *Derivative Financial Instruments*

The company uses derivative financial instruments for risk management purposes to manage certain exposures to fluctuations in interest rates, commodity prices, foreign exchange rates, and also for trading purposes. Gains or losses arising from risk management activities are reported in the same caption as the underlying item. Earnings impacts from trading activities are recorded on a net basis in Energy Supply and Trading Activities revenue.

#### *Hedge Accounting*

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment, which include fair value and cash flow hedges. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged portion of the underlying item are recognized in net earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is realized. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship. Any ineffectiveness in designated hedges is recognized in net earnings immediately.

### (r) Recent Accounting Pronouncements

#### *Business Combinations*

In 2009, the Canadian Institute of Chartered Accountants issued section 1582 “Business Combinations” to replace section 1581, and issued sections 1601 “Consolidated Financial Statements” and 1602 “Non-Controlling Interests” to replace section 1600 “Consolidated Financial Statements”. The new standards revised guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. Prospective application was effective for fiscal years beginning on or after January 1, 2011.

Early adoption was permitted, but the company applied section 1581 to the Petro-Canada business combination that occurred in August 2009.

## 2. SEGMENTED DISCLOSURES

The company has classified its continuing operations as follows:

- Oil Sands includes operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations.
- Natural Gas includes exploration and production of natural gas, crude oil and natural gas liquids, primarily in Western Canada.
- International and Offshore includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Libya, Syria, and Norway.
- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Canada and the U.S., as well as a lubricants plant located in Eastern Canada.
- Corporate, Energy Trading and Eliminations includes investments in renewable energy projects, third-party energy trading activities, and activities not directly attributable to an operating segment.

In 2010, the company combined its International and East Coast Canada segments into one segment, International and Offshore. All prior periods have been reclassified to conform to these segment definitions. Operations that have been discontinued are disclosed in note 6.

### Segmented Results of Continuing Operations

| | Oil Sands | | | Natural Gas | | | International and Offshore | | |
|---|---|---|---|---|---|---|---|---|---|
| For the years ended December 31 ($ millions) | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 |
| **EARNINGS** | | | | | | | | | |
| **Revenues** | | | | | | | | | |
| Operating revenues | **7 028** | 4 135 | 8 045 | **682** | 338 | 437 | **4 654** | 1 526 | — |
| Intersegment revenues | **2 758** | 2 609 | 1 309 | **124** | 121 | 34 | **593** | 159 | — |
| Less: Royalties | **(681)** | (645) | (715) | **(76)** | (36) | (107) | **(1 180)** | (469) | — |
| Operating revenues (net of royalties) | **9 105** | 6 099 | 8 639 | **730** | 423 | 364 | **4 067** | 1 216 | — |
| Energy supply and trading activities | **—** | — | — | **—** | — | — | **—** | — | — |
| Interest and other income | **318** | 440 | — | **4** | — | — | **256** | 1 | — |
| | **9 423** | 6 539 | 8 639 | **734** | 423 | 364 | **4 323** | 1 217 | — |
| **Expenses** | | | | | | | | | |
| Purchases of crude oil and products | **1 070** | 325 | 574 | **—** | — | — | **302** | 33 | — |
| Operating, selling and general | **4 545** | 4 277 | 3 203 | **338** | 233 | 120 | **414** | 164 | — |
| Energy supply and trading activities | **—** | — | — | **—** | — | — | **—** | — | — |
| Transportation | **291** | 248 | 229 | **94** | 41 | 11 | **89** | 38 | — |
| Depreciation, depletion and amortization | **1 318** | 922 | 580 | **773** | 287 | 137 | **1 172** | 299 | — |
| Accretion of asset retirement obligations | **120** | 111 | 55 | **29** | 14 | 4 | **27** | 10 | — |
| Exploration | **6** | 10 | 17 | **14** | 125 | 73 | **177** | 74 | — |
| Loss (gain) on disposal of assets | **14** | 70 | 36 | **(132)** | (20) | (22) | **2** | — | — |
| Project start-up costs | **74** | 51 | 35 | **—** | — | — | **3** | — | — |
| Financing expenses (income) | **(1)** | 1 | — | **(1)** | — | — | **(18)** | (1) | — |
| | **7 437** | 6 015 | 4 729 | **1 115** | 680 | 323 | **2 168** | 617 | — |
| **Earnings (loss) before income taxes** | **1 986** | 524 | 3 910 | **(381)** | (257) | 41 | **2 155** | 600 | — |
| Income taxes | **494** | (33) | 1 035 | **(104)** | (72) | 7 | **1 041** | 277 | — |
| **Net earnings (loss) from continuing operations** | **1 492** | 557 | 2 875 | **(277)** | (185) | 34 | **1 114** | 323 | — |
| **CAPITAL AND EXPLORATION EXPENDITURES – continuing operations** | **(3 709)** | (2 831) | (7 413) | **(170)** | (228) | (269) | **(927)** | (511) | — |

| For the years ended December 31 ($ millions) | Refining and Marketing 2010 | 2009 | 2008 | Corporate, Energy Trading and Eliminations 2010 | 2009 | 2008 | Total 2010 | 2009 | 2008 |
|---|---|---|---|---|---|---|---|---|---|
| **EARNINGS** | | | | | | | | | |
| **Revenues** | | | | | | | | | |
| Operating revenues | **20 769** | 11 800 | 9 257 | **65** | 178 | 181 | **33 198** | 17 977 | 17 920 |
| Intersegment revenues | **249** | 51 | — | **(3 724)** | (2 940) | (1 343) | **—** | — | — |
| Less: Royalties | **—** | — | — | **—** | — | — | **(1 937)** | (1 150) | (822) |
| Operating revenues (net of royalties) | **21 018** | 11 851 | 9 257 | **(3 659)** | (2 762) | (1 162) | **31 261** | 16 827 | 17 098 |
| Energy supply and trading activities | **—** | — | — | **2 700** | 7 577 | 11 320 | **2 700** | 7 577 | 11 320 |
| Interest and other income | **44** | — | 1 | **(233)** | 3 | 27 | **389** | 444 | 28 |
| | **21 062** | 11 851 | 9 258 | **(1 192)** | 4 818 | 10 185 | **34 350** | 24 848 | 28 446 |
| **Expenses** | | | | | | | | | |
| Purchases of crude oil and products | **17 100** | 9 607 | 8 367 | **(3 561)** | (2 577) | (1 335) | **14 911** | 7 388 | 7 606 |
| Operating, selling and general | **2 192** | 1 284 | 719 | **321** | 472 | 104 | **7 810** | 6 430 | 4 146 |
| Energy supply and trading activities | **—** | — | — | **2 598** | 7 381 | 11 323 | **2 598** | 7 381 | 11 323 |
| Transportation | **200** | 87 | 16 | **(18)** | (18) | (16) | **656** | 396 | 240 |
| Depreciation, depletion and amortization | **475** | 317 | 198 | **75** | 35 | 46 | **3 813** | 1 860 | 961 |
| Accretion of asset retirement obligations | **2** | 1 | 1 | **—** | — | — | **178** | 136 | 60 |
| Exploration | **—** | — | — | **—** | — | — | **197** | 209 | 90 |
| Loss (gain) on disposal of assets | **(30)** | 16 | 6 | **39** | — | (7) | **(107)** | 66 | 13 |
| Project start-up costs | **—** | — | — | **—** | — | — | **77** | 51 | 35 |
| Financing expenses (income) | **9** | 4 | — | **(19)** | (492) | 917 | **(30)** | (488) | 917 |
| | **19 948** | 11 316 | 9 307 | **(565)** | 4 801 | 11 032 | **30 103** | 23 429 | 25 391 |
| **Earnings (loss) before income taxes** | **1 114** | 535 | (49) | **(627)** | 17 | (847) | **4 247** | 1 419 | 3 055 |
| Income taxes | **313** | 128 | (27) | **(185)** | (87) | (42) | **1 559** | 213 | 973 |
| **Net earnings (loss) from continuing operations** | **801** | 407 | (22) | **(442)** | 104 | (805) | **2 688** | 1 206 | 2 082 |
| **CAPITAL AND EXPLORATION EXPENDITURES – continuing operations** | **(667)** | (380) | (207) | **(360)** | (70) | (58) | **(5 833)** | (4 020) | (7 947) |

## Goodwill and Total Assets by Segment

| As at December 31 ($ millions) | Goodwill 2010 | 2009 | Total Assets 2010 | 2009 |
|---|---|---|---|---|
| Oil Sands | **3 019** | 3 019 | **40 246** | 37 553 |
| Natural Gas | **—** | — | **3 091** | 3 369 |
| International and Offshore | **—** | — | **12 232** | 12 729 |
| Refining and Marketing | **182** | 182 | **11 778** | 10 304 |
| Corporate | **—** | — | **2 066** | 2 202 |
| Discontinued operations | **—** | — | **756** | 3 589 |
| Total | **3 201** | 3 201 | **70 169** | 69 746 |

## Geographic Information

| For the years ended December 31 ($ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Revenues** [1] | | | |
| Canada | **27 217** | 20 184 | 23 742 |
| U.S. | **4 804** | 4 010 | 4 794 |
| Other | **3 199** | 1 286 | 101 |
| Total | **35 220** | 25 480 | 28 637 |

(1) Includes revenues from continuing and discontinued operations.

| As at December 31 ($ millions) | **2010** | 2009 |
| --- | --- | --- |
| **Total assets** | | |
| Canada | **58 676** | 54 259 |
| U.S. | **3 332** | 5 239 |
| Other | **8 161** | 10 248 |
| Total | **70 169** | 69 746 |

### 3. BUSINESS COMBINATION WITH PETRO-CANADA

On August 1, 2009, Suncor completed its merger with Petro-Canada. The company has accounted for this business combination as prescribed by Canadian Institute of Chartered Accountants (CICA) Handbook section 1581 "Business Combinations". As the acquirer, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro-Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

The final calculation of the purchase price and allocation to assets and liabilities acquired as at August 1, 2009 is as follows:

| ($ millions) | |
| --- | --- |
| Calculation of Purchase Price: | |
| 621.1 million common shares issued to Petro-Canada shareholders | 18 878 |
| 7.1 million Petro-Canada share options exchanged for share options of Suncor | 147 |
| Transaction costs | 167 |
| Effective settlement of pre-existing contract with Petro-Canada | 438 |
| Total purchase price | 19 630 |
| Allocation of Purchase Price: | |
| Current assets | 4 645 |
| Property, plant and equipment | 27 407 |
| Other assets | 537 |
| Total assets | 32 589 |
| Current liabilities | 3 741 |
| Long-term debt | 4 410 |
| Accrued liabilities and other | 3 416 |
| Future income taxes | 4 570 |
| Total liabilities | 16 137 |
| Net assets purchased | 16 452 |
| Goodwill | 3 178 |
| Total purchase price | 19 630 |
| Goodwill Allocation: | |
| Oil Sands | 3 019 |
| Refining and Marketing | 159 |
| Total goodwill | 3 178 |

Cash acquired was $248 million, net of transaction costs of $167 million.

Other assets include $236 million for intangible assets, relating to the Petro-Canada brand, with an indefinite life, and customer lists, which will be amortized over their estimated useful lives.

Suncor and Petro-Canada had a fee-for-service contract in place prior to the merger, where effective January 1, 2009, Suncor had started upgrading bitumen supplied by Petro-Canada. At the date of the merger, the terms of the contract resulted in it being favourable to Suncor, and the assigned fair value of $438 million was recorded in Interest and Other Income.

### 4. BITUMEN VALUATION METHODOLOGY

In the fourth quarter of 2010, the Minister of Energy for Alberta provided notice to the company for the quality adjustment to be used under the Bitumen Valuation Methodology (Ministerial) Regulations for the interim period January 1, 2009 to December 31, 2010. As a result, the company recognized a royalty recovery of $140 million.

The company continues to negotiate final adjustments to the bitumen valuation calculation for the 2009 and 2010 interim period and for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015.

## 5. TERRA NOVA REDETERMINATION

In the fourth quarter of 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%, and the other owners have agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company has recognized a $295 million gain in Interest and Other Income.

Suncor's financial presentation will reflect the increased working interest in Terra Nova beginning January 1, 2011.

## 6. DISCONTINUED OPERATIONS

During 2010, the company divested certain non-core assets as part of its continuing strategic alignment.

### Natural Gas

In the first quarter of 2010, the company completed the sale of its oil and gas producing assets in the U.S. Rockies for net proceeds of US$481 million (Cdn$502 million).

In the second quarter of 2010, the company completed the sale of non-core natural gas properties located in northeast British Columbia (Blueberry and Jedney) for net proceeds of $383 million, and non-core assets in central Alberta (Rosevear and Pine Creek) for net proceeds of $229 million.

In the third quarter of 2010, the company completed the sale of non-core natural gas properties located in west central Alberta (Bearberry and Ricinus) for net proceeds of $275 million, and non-core assets in southern Alberta (Wildcat Hills) for net proceeds of $351 million.

### International and Offshore

In the third quarter of 2010, the company completed the Trinidad and Tobago asset sale, for net proceeds of US$378 million (Cdn$383 million), and the sale of its shares in Petro-Canada Netherlands BV, for net proceeds of €316 million (Cdn$420 million).

In the fourth quarter of 2010, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £55 million (Cdn$86 million). The company expects to close the remaining agreed sales of non-core U.K. offshore assets for gross proceeds of £184 million in the first half of 2011.

Net income from discontinued operations reported in the Consolidated Statements of Earnings is as follows:

| | Natural Gas | | | International and Offshore | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| For the years ended December 31 ($ millions) | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 |
| **Revenues** | | | | | | | | | |
| Operating revenues (1) | **280** | 307 | 283 | **693** | 407 | — | **973** | 714 | 283 |
| Less: Royalties | **(41)** | (49) | (68) | **—** | — | — | **(41)** | (49) | (68) |
| Operating revenues (net of royalties) | **239** | 258 | 215 | **693** | 407 | — | **932** | 665 | 215 |
| Gain on disposal of assets | **642** | — | — | **172** | — | — | **814** | — | — |
| | **881** | 258 | 215 | **865** | 407 | — | **1 746** | 665 | 215 |
| **Expenses** | | | | | | | | | |
| Operating, selling and general | **66** | 89 | 40 | **119** | 150 | — | **185** | 239 | 40 |
| Transportation | **24** | 17 | 6 | **23** | 14 | — | **47** | 31 | 6 |
| Depreciation, depletion and amortization (2) | **95** | 161 | 88 | **169** | 285 | — | **264** | 446 | 88 |
| Accretion of asset retirement obligations | **8** | 8 | 4 | **19** | 11 | — | **27** | 19 | 4 |
| Exploration | **1** | 2 | — | **20** | 57 | — | **21** | 59 | — |
| Financing expenses (income) | **7** | — | — | **11** | 1 | — | **18** | 1 | — |
| | **201** | 277 | 138 | **361** | 518 | — | **562** | 795 | 138 |
| **Earnings before income taxes** | **680** | (19) | 77 | **504** | (111) | — | **1 184** | (130) | 77 |
| Income taxes | **174** | (5) | 22 | **127** | (65) | — | **301** | (70) | 22 |
| **Net earnings (loss)** | **506** | (14) | 55 | **377** | (46) | — | **883** | (60) | 55 |

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These totaled $62 million in the year ended December 31, 2010 (2009 – $33 million, 2008 – $24 million).

(2) For the year ended December 31, 2010, depreciation, depletion and amortization includes a write-down of $106 million in International and Offshore, and a write-down of $27 million in Natural Gas (2009 – write-down of $83 million in International and Offshore, 2008 – $nil).

| For the years ended December 31 (dollars) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Basic earnings per share from discontinued operations | **0.57** | (0.05) | 0.06 |
| Diluted earnings per share from discontinued operations | **0.56** | (0.05) | 0.06 |

The assets and liabilities of discontinued operations presented in the Consolidated Balance Sheets are as follows:

| | Natural Gas | | International and Offshore | | Total | |
|---|---|---|---|---|---|---|
| As at December 31 ($ millions) | **2010** | 2009 | **2010** | 2009 | **2010** | 2009 |
| **Assets** | | | | | | |
| Current assets | — | 34 | **98** | 223 | **98** | 257 |
| Property, plant and equipment, net | — | 1 600 | **658** | 1 732 | **658** | 3 332 |
| Total assets | — | 1 634 | **756** | 1 955 | **756** | 3 589 |
| **Liabilities** | | | | | | |
| Current liabilities | — | 64 | **98** | 178 | **98** | 242 |
| Accrued liabilities and other | — | 286 | **302** | 404 | **302** | 690 |
| Future income taxes | — | 31 | **182** | 472 | **182** | 503 |
| Total liabilities | — | 381 | **582** | 1 054 | **582** | 1 435 |

## 7. ENERGY TRADING ACTIVITIES

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Non-trading physical contracts (1) | **3 957** | 8 008 | 11 295 |
| Change in fair value of contracts entered into for trading purposes (1) | **81** | (50) | 127 |
| Gains (losses) on inventory valuation | **(4)** | 47 | — |
| Less: Intercompany eliminations | **(1 334)** | (428) | (102) |
| Energy Supply and Trading Activities revenue | **2 700** | 7 577 | 11 320 |
| | | | |
| Non-trading physical contracts (1) | **3 932** | 7 929 | 11 331 |
| Less: Intercompany eliminations | **(1 334)** | (548) | (8) |
| Energy Supply and Trading Activities expense | **2 598** | 7 381 | 11 323 |

(1) The merger with Petro-Canada in 2009 provided the company with the ability to capitalize on future trading opportunities due to increased transactional and trading capacity. The company determined that the new transaction levels for certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements. Effective October 1, 2009, these contracts are now considered derivative financial instruments, whereby realized and unrealized gains and losses and the underlying settlement of these contracts is now recognized and reported on a net basis in the Energy Supply and Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Supply and Trading Activities revenue.

Prior to October 1, 2009 the settlement of these contracts was recorded on a gross basis within Energy Supply and Trading Activities revenue and Energy Supply and Trading Activities expense.

## 8. FINANCING EXPENSES (INCOME)

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Interest on debt | **691** | 573 | 352 |
| Capitalized interest | **(301)** | (136) | (352) |
| Interest expense | **390** | 437 | — |
| Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt | **(426)** | (858) | 919 |
| Foreign exchange loss (gain) and other | **6** | (67) | (2) |
| Total financing expenses (income) from continuing operations (1) | **(30)** | (488) | 917 |

(1) For 2010, financing expense of $18 million (2009 – financing income of $1 million, 2008 – $nil) has been reclassified to net earnings from discontinued operations.

## 9. INCOME TAXES

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Earnings before income taxes | **4 247** | 1 419 | 3 055 |
| Canadian statutory tax rate | **28.91%** | 30.95% | 29.52% |
| Statutory tax | **1 228** | 439 | 902 |
| Add (deduct) the tax effect of: | | | |
| Non-taxable component of capital gains and losses | **(67)** | (133) | 136 |
| Stock-based compensation and other permanent items | **1** | 42 | 36 |
| Assessments and adjustments | **20** | (42) | (48) |
| Effect of changes to statutory enacted rates | **—** | (148) | — |
| Impact of income tax rate adjustments on future income tax liabilities | **(15)** | 152 | — |
| Change in valuation allowance | **—** | (59) | — |
| Canadian tax rate differential | **(71)** | (28) | (112) |
| Foreign tax rate differential | **459** | 115 | 12 |
| Non-taxable gain on effective settlement of pre-existing contract with Petro-Canada | **—** | (105) | — |
| Other | **4** | (20) | 47 |
| Provision for income taxes from continuing operations (1) | **1 559** | 213 | 973 |

(1) For the year ended December 31, 2010, income tax expense of $301 million (2009 – income tax recovery of $70 million, 2008 – income tax expense of $22 million) has been reclassified to net earnings from discontinued operations.

At December 31, geographic distribution of income tax provisions were as follows:

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Provision for (recovery of) income taxes: | | | |
| Current: | | | |
| Canada | **57** | 599 | 493 |
| Foreign | **947** | 242 | 21 |
| Future: | | | |
| Canada | **569** | (699) | 493 |
| Foreign | **(14)** | 71 | (34) |
| Provision for income taxes from continuing operations | **1 559** | 213 | 973 |

At December 31, future income taxes related to continuing operations were comprised of the following:

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Future income tax liabilities: | | |
| Property, plant and equipment | **9 798** | 9 167 |
| Risk management and energy trading | **27** | — |
| Other | **212** | 177 |
| Future income tax assets: | | |
| Asset retirement obligations | **(640)** | (813) |
| Employee future benefits | **(401)** | (352) |
| Risk management and energy trading | **—** | (113) |
| Other assets | **(610)** | (206) |
| Net future income tax liabilities | **8 386** | 7 860 |
| Less: Current portion of future income tax (assets)/liabilities | **(173)** | (314) |
| Future income tax liabilities (1) | **8 559** | 8 174 |

(1) For 2010, future income tax liabilities of $182 million (2009 – $503 million) have been reclassified to liabilities of discontinued operations.

Included in the above table are unused non-capital tax losses of $955 million (2009 – $464 million), the majority of which relate to Canada and are available to reduce taxable income in future years. These non-capital tax losses will expire between 2026 and 2030.

Deferred distribution taxes associated with International and Offshore business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

### 10. EARNINGS PER COMMON SHARE

Net earnings per common share is calculated by dividing net earnings by the weighted-average number of common shares outstanding.

| (millions of common shares) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Weighted-average number of common shares | **1 562** | 1 198 | 932 |
| Dilutive effect of stock options | **12** | 13 | 13 |
| Weighted-average number of diluted common shares | **1 574** | 1 211 | 945 |

### 11. CASH AND CASH EQUIVALENTS

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Cash | **358** | 205 |
| Cash equivalents | **719** | 300 |
| Total | **1 077** | 505 |

### 12. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital from continuing operations is comprised of:

| ($ millions) | **2010** | 2009 (1) | 2008 |
|---|---|---|---|
| Accounts receivable | **(699)** | 105 | 230 |
| Inventories | **(190)** | (585) | 103 |
| Accounts payable and accrued liabilities | **(79)** | (511) | (235) |
| Taxes payable/receivable | **(458)** | (37) | (110) |
| Total | **(1 426)** | (1 028) | (12) |
| Relating to: | | | |
| Operating activities | **(1 230)** | (237) | 403 |
| Investing activities | **(196)** | (791) | (415) |

(1) Balances do not include amounts acquired from Petro-Canada as a result of the merger, but do reflect the changes in these working capital accounts subsequent to August 1, 2009.

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Interest paid | **839** | 581 | 328 |
| Income taxes paid | **1 193** | 872 | 638 |

### 13. INVENTORIES

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Crude oil | **916** | 776 |
| Refined products | **1 289** | 1 303 |
| Materials, supplies and merchandise | **564** | 513 |
| Energy trading commodity inventories (1) | **372** | 355 |
| Total (2) | **3 141** | 2 947 |

(1) Recorded at fair value.
(2) For 2010, inventories of $11 million (2009 – $24 million) have been reclassified to current assets of discontinued operations.

During 2010, product inventories of $17.2 billion (2009 – $14.9 billion) were expensed.

## 14. PROPERTY, PLANT AND EQUIPMENT

| ($ millions) | 2010 Cost | 2010 Accumulated Provision | 2009 Cost | 2009 Accumulated Provision |
|---|---|---|---|---|
| Oil Sands | | | | |
| Oil and gas properties | **4 320** | **644** | 3 978 | 469 |
| Plant and equipment | **21 760** | **4 663** | 18 930 | 3 687 |
| Assets not subject to depreciation or depletion | **13 980** | **—** | 13 929 | — |
| | **40 060** | **5 307** | 36 837 | 4 156 |
| Natural Gas | | | | |
| Oil and gas properties | **4 000** | **1 619** | 3 812 | 1 034 |
| Plant and equipment | **250** | **109** | 234 | 70 |
| Assets not subject to depreciation or depletion | **22** | **—** | 27 | — |
| | **4 272** | **1 728** | 4 073 | 1 104 |
| International and Offshore | | | | |
| Oil and gas properties | **7 046** | **1 407** | 6 526 | 294 |
| Plant and equipment | **741** | **62** | 100 | 31 |
| Assets not subject to depreciation or depletion | **3 886** | **—** | 4 806 | — |
| | **11 673** | **1 469** | 11 432 | 325 |
| Refining and Marketing | | | | |
| Plant and equipment | **7 668** | **1 935** | 7 433 | 1 649 |
| Assets not subject to depreciation or depletion | **1 392** | **—** | 1 264 | — |
| | **9 060** | **1 935** | 8 697 | 1 649 |
| Corporate and Energy Trading | | | | |
| Plant and equipment | **575** | **236** | 483 | 181 |
| Assets not subject to depreciation or depletion | **325** | **—** | 91 | — |
| | **900** | **236** | 574 | 181 |
| | **65 965** | **10 675** | 61 613 | 7 415 |
| Net property, plant and equipment(1) | | **55 290** | | 54 198 |

(1) For 2010, net property, plant and equipment of $658 million (2009 – $3,332 million) has been reclassified to discontinued operations.

Assets not subject to depreciation or depletion primarily consists of development assets and assets under construction.

Property, plant and equipment, at December 31, 2010, includes Oil Sands capital leases at a net book value of $257 million (2009 – $225 million) and International and Offshore capital leases at a net book value of $45 million (2009 – $48 million).

## 15. ASSET WRITE-DOWNS

During the second quarter of 2010, the company recognized a write-down of $189 million related to certain extraction equipment in the Oil Sands operating segment. These assets were being used in the development of an alternative extraction process to crush and slurry oil sands at the mine face, which the company has discontinued.

During the second quarter of 2010, the company recognized a write-down of $44 million of certain land leases in the Natural Gas operating segment. These assets are in areas of Western Canada and Alaska that the company does not plan to pursue given its strategic business alignment.

During the third quarter of 2010, the company recognized a charge of $222 million to reflect the write-down of certain assets in the Natural Gas operating segment to reflect fair value based on discounted future cash flows.

Also during the third quarter of 2010, the company recognized a write-down of $106 million related to certain North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during the quarter and the assets were written down to reflect fair value less cost to sell.

During 2009, the company recognized a write-down of $83 million to reflect the fair value of certain non-core North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during 2009 and the assets were written down to reflect fair value less cost to sell. There were no write-downs recognized in 2008.

These charges are included in depreciation, depletion and amortization expenses and net earnings from discontinued operations in the Consolidated Statements of Earnings.

## 16. OTHER ASSETS

| ($ millions) | 2010 | 2009 |
|---|---|---|
| Intangible assets | **222** | 233 |
| Investments | **135** | 148 |
| Other | **94** | 110 |
| Total | **451** | 491 |

Intangible assets acquired in 2009 as part of the business combination with Petro-Canada include $166 million related to the Petro-Canada brand, which has an indefinite life, and $70 million related to Petro-Canada customer lists which are amortized over their estimated useful lives ranging from five to ten years. During 2010, amortization expense related to intangible assets was $11 million (2009 – $4 million; 2008 – $nil).

## 17. LONG-TERM DEBT AND CREDIT FACILITIES

| ($ millions) | 2010 | 2009 |
|---|---|---|
| **Fixed-term debt, redeemable at the option of the company** | | |
| 6.85% Notes, due in 2039 (US$750) | **746** | 785 |
| 6.80% Notes, due in 2038 (US$900) | **922** | 972 |
| 6.50% Notes, due in 2038 (US$1150) | **1 144** | 1 204 |
| 5.95% Notes, due in 2035 (US$600) | **552** | 578 |
| 5.95% Notes, due in 2034 (US$500) | **497** | 523 |
| 5.35% Notes, due in 2033 (US$300) | **255** | 266 |
| 7.15% Notes, due in 2032 (US$500) | **497** | 523 |
| 6.10% Notes, due in 2018 (US$1250) | **1 243** | 1 308 |
| 6.05% Notes, due in 2018 (US$600) | **609** | 643 |
| 5.00% Notes, due in 2014 (US$400) | **406** | 429 |
| 4.00% Notes, due in 2013 (US$300) | **298** | 313 |
| 7.00% Debentures, due in 2028 (US$250) | **257** | 271 |
| 7.875% Debentures, due in 2026 (US$275) | **307** | 325 |
| 9.25% Debentures, due in 2021 (US$300) | **375** | 402 |
| 5.39% Series 4 Medium Term Notes, due in 2037 | **600** | 600 |
| 5.80% Series 4 Medium Term Notes, due in 2018 | **700** | 700 |
| 6.70% Series 2 Medium Term Notes, due in August 2011 (i) | **500** | 500 |
| | **9 908** | 10 342 |
| **Revolving-term debt, with variable interest rates** | | |
| Commercial paper (ii), bankers' acceptances and LIBOR loans (interest rate at December 31, 2010 – 1.2%, 2009 – 0.7%) | **1 982** | 3 244 |
| Total unsecured long-term debt | **11 890** | 13 586 |
| Secured long-term debt | **13** | 13 |
| Capital leases (iii) | **335** | 326 |
| Fair value adjustment related to interest rate swaps | **8** | 18 |
| Deferred financing costs | **(59)** | (63) |
| | **12 187** | 13 880 |
| Current portion of long-term debt | | |
| 6.70% Series 2 Medium Term Notes, due in August 2011 (i) | **(500)** | — |
| Capital leases (iii) | **(10)** | (14) |
| Fair value adjustment related to interest swaps | **(8)** | (11) |
| Total current portion of long-term debt | **(518)** | (25) |
| Total long-term debt | **11 669** | 13 855 |

(i) The company has entered into interest rate swap transactions on $200 million of the principal amount of this note. The interest rate swaps resulted in an average effective interest rate on the $200 million principal of 1.9% in 2010 (2009 – 2.0%).

(ii) The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. Commercial paper is supported by unutilized credit facilities.

(iii) Interest rates range from 4.7% to 13.4%, and maturity dates range from 2012 to 2037.

**Required Debt Repayments**

Required debt repayments for capital leases and long-term debt are as follows:

| ($ millions) | |
|---|---|
| 2011 | **2 492** |
| 2012 | **10** |
| 2013 | **322** |
| 2014 | **418** |
| 2015 | **13** |
| Thereafter | **8 983** |
| Total | **12 238** |

**Credit Facilities**

A summary of available and unutilized credit facilities is as follows:

| ($ millions) | **2010** |
|---|---|
| Term period of one year and expires in 2011 | **4** |
| Fully revolving for a period of four years and expires in 2013 | **199** |
| Fully revolving for a period of five years and expires in 2013 | **7 320** |
| Can be terminated at any time at the option of the lenders | **461** |
| Total available credit facilities | **7 984** |
| Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans | **(1 982)** |
| Credit facilities supporting standby letters of credit | **(713)** |
| Total unutilized credit facilities | **5 289** |

## 18. ACCRUED LIABILITIES AND OTHER

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Asset retirement obligations [(a)] | **1 969** | 2 198 |
| Employee future benefits liability (note 19) | **1 060** | 1 128 |
| Stock-based compensation plans [(b)] | **304** | 219 |
| Deferred revenue | **94** | 94 |
| Contract provisions [(c)] | **224** | 33 |
| Long-term financial liabilities [(d)] | **365** | 602 |
| Other | **138** | 98 |
| Total | **4 154** | 4 372 |

### (a) Asset Retirement Obligations (ARO)

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

| ($ millions) | **2010** | 2009 |
|---|---|---|
| Asset retirement obligations, beginning of year | **3 200** | 1 600 |
| Liabilities incurred | **80** | 253 |
| Changes in estimates | **(157)** | (145) |
| Liabilities settled | **(417)** | (248) |
| Accretion | **205** | 155 |
| Asset divestitures | **(441)** | — |
| Petro-Canada liabilities acquired | **—** | 1 605 |
| Foreign exchange | **(52)** | (20) |
| Asset retirement obligations, end of year | **2 418** | 3 200 |
| Less: Current portion | **147** | 312 |
| Less: Amount related to discontinued operations | **302** | 690 |
| | **1 969** | 2 198 |

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2010, was approximately $7.4 billion (2009 – $8.3 billion). Substantially all of the liability recognized in 2010 was discounted using a weighted-average credit-adjusted risk free rate of 5.4% (2009 – 6.2%). The credit-adjusted risk-free rate used reflects the expected timeframe of the related liability. Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the downstream refineries, have retirement obligations for which the fair value cannot be reasonably determined because the expected timing of the reclamation activity cannot be estimated at this time. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

### (b) Stock-Based Compensation Plans

The current portion of the stock-based compensation plans of $240 million (2009 – $198 million) is included in current liabilities. See note 20 for further information on the company's liability-based stock-based compensation awards.

### (c) Contract Provisions

Amount relates to provisions for future pipeline leases with terms extending to 2015, and building leases with terms extending to 2019.

### (d) Long-Term Financial Liabilities

As part of the acquisition of Petro-Canada in 2009, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project in 2007 from another partner in the project. To pay for this investment the company will fund $375 million of expenditures in excess of its working interest. At December 31, 2010, the discounted carrying amount of the Fort Hills obligation was $327 million (2009 – $322 million).

The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements in Libya in 2008, payable in several installments through 2013. At December 31, 2010, the carrying amount of the Libya obligation was $287 million (2009 – $511 million), of which the current portion is $249 million (2009 – $231 million) and is recorded in accounts payable and accrued liabilities.

## 19. EMPLOYEE FUTURE BENEFITS LIABILITY

*Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire under the terms of the company's defined benefit plans.*

*The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.*

### Defined Benefit Pension Plans and Other Post-Retirement Benefits

The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unregistered supplementary pensions and senior executive retirement plans that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation was performed as at December 31, 2010. The next valuation will be performed as at December 31, 2011.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

### Defined Benefit Obligations and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

| ($ millions) | Pension Benefits 2010 | Pension Benefits 2009 | Other Post-Retirement Benefits 2010 | Other Post-Retirement Benefits 2009 |
|---|---|---|---|---|
| **Change in benefit obligation** | | | | |
| Benefit obligation at beginning of year | **2 855** | 806 | **424** | 149 |
| Service costs | **85** | 64 | **8** | 6 |
| Interest costs | **168** | 96 | **25** | 15 |
| Plan participants' contributions | **11** | 17 | **—** | — |
| Foreign exchange | **(14)** | (13) | **(1)** | (4) |
| Actuarial loss | **265** | 59 | **39** | 1 |
| Benefits paid | **(151)** | (86) | **(12)** | (8) |
| Plan acquisition upon merger[(a)] | **—** | 1 912 | **—** | 265 |
| Benefit obligation at end of year[(b),(e)] | **3 219** | 2 855 | **483** | 424 |
| **Change in plan assets**[(c)] | | | | |
| Fair value of plan assets at beginning of year | **2 072** | 613 | **—** | — |
| Actual return on plan assets | **224** | 175 | **—** | — |
| Employer contributions | **188** | 105 | **—** | — |
| Foreign exchange | **(9)** | (7) | **—** | — |
| Plan participants' contributions | **11** | 17 | **—** | — |
| Benefits paid | **(151)** | (86) | **—** | — |
| Plan acquisition upon merger | **—** | 1 255 | **—** | — |
| Fair value of plan assets at end of year[(e)] | **2 335** | 2 072 | **—** | — |
| Net unfunded obligation | **(884)** | (783) | **(483)** | (424) |
| Items not yet recognized in earnings: | | | | |
| Unamortized net actuarial loss[(d)] | **234** | 50 | **45** | 8 |
| Unamortized past service costs | **5** | 9 | **(11)** | (14) |
| Accrued benefit liability | **(645)** | (724) | **(449)** | (430) |
| Current liability | **(38)** | (30) | **(3)** | (3) |
| Long-term liability | **(614)** | (701) | **(446)** | (427) |
| Long-term asset | **7** | 7 | **—** | — |
| Total accrued benefit liability | **(645)** | (724) | **(449)** | (430) |

(a) The valuation of accrued benefit obligations for plans acquired through the business combination with Petro-Canada assumed a discount rate of 5.25%, a rate of compensation increase of 3.00% and an expected return on plan assets rate of 6.75%.

(b) Obligations are based on the following assumptions:

| (per cent) | Pension Benefit Obligations 2010 | Pension Benefit Obligations 2009 | Other Post-Retirement Benefits Obligations 2010 | Other Post-Retirement Benefits Obligations 2009 |
|---|---|---|---|---|
| Discount rate | **5.10** | 5.85 | **5.25** | 6.00 |
| Rate of compensation increase | **3.70** | 3.90 | **4.00** | 4.00 |

Assumed health care cost trend rates may have a significant effect on the amounts reported for other post-retirement benefit obligations. A one per cent change in assumed health care cost trend rates would have the following effects:

| ($ millions) | 1% increase | 1% decrease |
|---|---|---|
| Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost | 2 | (2) |
| Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation | 38 | (31) |

(c) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(d) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 7 years for pension benefits (2009 – 7 years; 2008 – 11 years), and over the expected average future service life to full eligibility age of 14 years for other post-retirement benefits (2009 – 11 years; 2008 – 11 years).

(e) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes partially funded and unfunded plans, as follows:

| ($ millions) | Pension Benefits 2010 | 2009 | Other Post-Retirement Benefits 2010 | 2009 |
|---|---|---|---|---|
| Partially funded plans | **3 219** | 2 855 | **—** | — |
| Unfunded plans | **—** | — | **483** | 424 |
| Benefit obligation at end of year | **3 219** | 2 855 | **483** | 424 |

**Benefit Plans Expense**

| ($ millions) | Pension Benefits 2010 | 2009 | 2008 | Other Post-Retirement Benefits 2010 | 2009 | 2008 |
|---|---|---|---|---|---|---|
| Current service costs | **85** | 64 | 56 | **8** | 6 | 4 |
| Interest costs | **168** | 96 | 49 | **25** | 15 | 9 |
| Actual (return) loss on plan assets (i) | **(224)** | (175) | 107 | **—** | — | — |
| Actuarial (gain) loss | **265** | 59 | (168) | **39** | 1 | (27) |
| Pension expense before adjustments for the long-term nature of employee future benefit costs | **294** | 44 | 44 | **72** | 22 | (14) |
| Difference between actual and expected return on plan assets (i) | **82** | 98 | (152) | **—** | — | — |
| Difference between actual and recognized actuarial losses | **(260)** | (36) | 188 | **(36)** | 3 | 33 |
| Difference between actual and recognized past service costs | **2** | 2 | 2 | **(3)** | (3) | (3) |
| Defined benefit plans expense (ii) | **118** | 108 | 82 | **33** | 22 | 16 |
| Defined contribution plans expense | **40** | 28 | 15 | **—** | — | — |
| Total benefit plans expense | **158** | 136 | 97 | **33** | 22 | 16 |

(i) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between the expected rate and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 7 years for pension benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(ii) Defined benefit plans pension expense is based on the following assumptions:

| (per cent) | Pension Benefit Expense 2010 | 2009 | 2008 | Other Post-Retirement Benefits Expense 2010 | 2009 | 2008 |
|---|---|---|---|---|---|---|
| Discount rate | **5.85** | 6.50 | 5.25 | **6.00** | 6.00 | 5.25 |
| Expected return on plan assets | **6.65** | 6.70 | 6.50 | **N/A** | N/A | N/A |
| Rate of compensation increase | **3.90** | 3.90 | 5.00 | **4.00** | 4.00 | 4.75 |

### Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2010 and 2009, and the target allocation for 2011, are as follows:

| Asset Category | Target Allocation % 2011 | Plan Assets % **2010** | Plan Assets % 2009 |
|---|---|---|---|
| Equities | 58 | **58** | 59 |
| Fixed income | 42 | **42** | 41 |
| Total | 100 | **100** | 100 |

Equity securities do not include any direct investments in Suncor shares.

### Cash Flows

The company expects that cash contributions to its defined benefit pension plans in 2011 will be $193 million. Expected benefit payments from all of the plans for the next ten years are as follows:

| | Pension Benefits | Other Post-Retirement Benefits |
|---|---|---|
| 2011 | 153 | 19 |
| 2012 | 162 | 21 |
| 2013 | 170 | 22 |
| 2014 | 178 | 24 |
| 2015 | 186 | 25 |
| 2016 – 2020 | 1 035 | 146 |
| Total | 1 884 | 257 |

## 20. SHARE CAPITAL

### Authorized

***Common Shares***

The company is authorized to issue an unlimited number of common shares without nominal or par value.

***Preferred Shares***

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

### Issued

| | Common Shares Number (thousands) | Common Shares Amount ($ millions) |
|---|---|---|
| Balance as at December 31, 2007 | 925 566 | 881 |
| Issued for cash under stock options plan | 9 823 | 226 |
| Issued under dividend reinvestment plan | 135 | 6 |
| Balance as at December 31, 2008 | 935 524 | 1 113 |
| Shares issued to Petro-Canada shareholders on merger | 621 142 | 18 878 |
| Issued for cash under stock options plan | 2 968 | 57 |
| Issued under dividend reinvestment plan | 144 | 5 |
| Balance as at December 31, 2009 | 1 559 778 | 20 053 |
| Issued for cash under stock option plans | **5 292** | **122** |
| Issued under dividend reinvestment plan | **419** | **13** |
| **Balance as at December 31, 2010** | **1 565 489** | **20 188** |

**Stock-Based Compensation**

A stock option gives the holder the right to purchase common shares at or greater than the grant date market price subject to fulfilling vesting terms. Certain options are subject to accelerated vesting should the company meet predetermined performance criteria.

**(a) Stock Option Plans**

**Continuing plans**

***(i) Suncor Energy Inc. Stock Options***

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. These options have a seven-year life and vest annually over a three-year period.

Options granted under this plan before August 1, 2010 included a tandem stock appreciation right (TSAR). The company granted 4,275,000 options with TSARs during 2010 (2009 - 4,000). Effective August 1, 2010, options granted under this plan no longer include TSARs. The company granted 22,000 options with no TSARs during 2010.

**Discontinued plans**

The following plans were discontinued on August 1, 2009:

***(i) SunShare 2012 Performance Stock Option Plan***

Options under this plan were granted to all eligible permanent full-time and part-time employees. On January 1, 2010, 25% of the outstanding options vested. The remaining 75% of outstanding options may vest on January 1, 2013 if further specified performance targets are met. All outstanding unvested options at January 1, 2013, will automatically expire.

***(ii) Executive Stock Plan***

Options under this plan were granted to non-employee directors and certain executives and other senior employees of the company. Options granted have a 10-year life and vest annually over a three-year period.

***(iii) Key Contributor Stock Option Plan***

Options under this plan were granted to non-insider senior managers and key employees. Options granted have a 10-year life and vest annually over a three-year period.

***(iv) Petro-Canada Stock Options ("Adjusted Options")***

The Adjusted Options, issued to officers and certain employees, have a 10-year life if granted prior to 2004 and seven years if granted subsequent to 2003. Options granted after 2003 can be exercised for a cash payment alternative (CPA) and are therefore recorded at their intrinsic value at each period end. All Adjusted Options vest over periods of up to four years.

Changes in the number of outstanding stock options were as follows:

| | Number (thousands) | Range of Exercise Prices Per Share ($) | Weighted-Average Exercise Price Per Share ($) |
|---|---|---|---|
| Outstanding, December 31, 2008 | 46 402 | 5.06 – 69.97 | 34.55 |
| Granted | 2 490 | 20.99 – 49.67 | 35.78 |
| Adjusted options issued to Petro-Canada stock option holders | 29 900 | 8.22 – 44.27 | 28.05 |
| Exercised | (2 870) | 5.06 – 36.68 | 13.69 |
| Forfeited/expired | (3 898) | 13.31 – 71.12 | 40.48 |
| Outstanding, December 31, 2009 | 72 024 | 7.84 – 72.68 | 32.52 |
| Granted | **4 297** | **30.93 – 35.76** | **31.86** |
| Exercised | **(5 292)** | **7.84 – 47.55** | **15.49** |
| Forfeited/expired | **(3 391)** | **13.82 – 67.58** | **42.51** |
| **Outstanding, December 31, 2010** | **67 638** | **8.72 – 69.97** | **32.94** |
| **Exercisable, December 31, 2010** | **46 266** | **8.72 – 69.97** | **29.91** |

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

| (thousands of common shares) | **2010** | 2009 | 2008 |
|---|---|---|---|
| | **18 854** | 22 306 | 12 345 |

Outstanding and exercisable common share options as at December 31, 2010:

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Exercise Prices ($) | Number (thousands) | Weighted-Average Remaining Contractual Life (years) | Weighted-Average Exercise Price Per Share ($) | Number (thousands) | Weighted-Average Exercise Price Per Share ($) |
| 8.72 – 14.99 | 11 582 | 1 | 13.34 | 11 582 | 13.34 |
| 15.00 – 19.99 | 5 062 | 4 | 18.69 | 2 720 | 18.05 |
| 20.00 – 29.99 | 10 075 | 2 | 22.88 | 9 206 | 23.15 |
| 30.00 – 44.99 | 20 812 | 4 | 37.37 | 13 885 | 39.26 |
| 45.00 – 49.99 | 18 872 | 4 | 47.35 | 8 495 | 47.07 |
| 50.00 – 69.97 | 1 235 | 4 | 58.35 | 378 | 58.01 |
| Total | 67 638 | 3 | 32.94 | 46 266 | 29.91 |

**Fair Value of Options Granted**

The fair values of common share options that do not have the option of cash settlement are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 plan and the Black-Scholes option-pricing model for all other plans. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Annual dividend per share | **$0.40** | $0.30 | $0.20 |
| Risk-free interest rate | **2.02%** | 2.31% | 3.35% |
| Expected life | **5 years** | 5 years | 6 years |
| Expected volatility | **50%** | 47% | 30% |
| Weighted-average fair value per option | **$12.98** | $10.28 | $13.86 |

**(b) Stock Appreciation Rights (SARs)**

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised.

**Continuing plan**

***(i) Suncor Energy Inc. SARs***

These SARs have a seven-year life and vest annually over a three-year period. The company granted 353,000 SARs during 2010 (2009 – nil).

**Discontinued plan**

***(i) Petro-Canada SARs***

Legacy Petro-Canada had a SARs plan for which grants ended on July 31, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Changes in the number of outstanding SARs were as follows:

| | Number (thousands) | Range of Exercise Prices Per Share ($) | Weighted-Average Exercise Price Per Share ($) |
|---|---|---|---|
| SARs issued to holders of Petro-Canada SARs, August 1, 2009 | 15 353 | 19.13 – 46.13 | 28.74 |
| Exercised | (306) | 19.13 – 39.41 | 35.01 |
| Forfeited | (982) | 19.13 – 46.13 | 28.28 |
| Outstanding, December 31, 2009 | 14 065 | 19.13 – 46.13 | 28.63 |
| Granted | **353** | **31.67 – 32.48** | **31.85** |
| Exercised | **(734)** | **19.13 – 36.82** | **24.00** |
| Forfeited | **(2 399)** | **19.44 – 46.13** | **28.99** |
| **Outstanding, December 31, 2010** | **11 285** | **19.13 – 46.13** | **28.97** |
| **Exercisable, December 31, 2010** | **4 939** | **19.13 – 46.13** | **32.28** |

Outstanding and exercisable SARs as at December 31, 2010:

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Exercise Prices ($) | Number (thousands) | Weighted-Average Remaining Contractual Life (years) | Weighted-Average Exercise Price Per Share ($) | Number (thousands) | Weighted-Average Exercise Price Per Share ($) |
| 19.13 – 24.99 | 4 649 | 5 | 19.45 | 1 002 | 19.46 |
| 25.00 – 34.99 | 3 174 | 3 | 34.13 | 2 171 | 34.29 |
| 35.00 – 39.99 | 3 368 | 4 | 36.84 | 1 701 | 36.85 |
| 40.00 – 46.13 | 94 | 4 | 43.70 | 65 | 43.66 |
| Total | 11 285 | 4 | 28.97 | 4 939 | 32.28 |

**(c) Share Unit Plans**

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at time of vesting. Typically, RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs.

Changes in the number of outstanding share units were as follows:

| Number (thousands) | PSU | RSU | DSU |
|---|---|---|---|
| Outstanding, December 31, 2008 | 2 175 | 965 | 1 903 |
| Granted | 1 149 | 2 715 | 104 |
| Units issued to Petro-Canada unitholders | 945 | 1 018 | 1 008 |
| Redeemed for cash | (69) | (21) | (443) |
| Forfeited | (957) | (432) | — |
| Reinvested | 4 | 5 | 44 |
| Outstanding, December 31, 2009 | 3 247 | 4 250 | 2 616 |
| Granted | **1 673** | **2 838** | **80** |
| Redeemed for cash | **(282)** | **(118)** | **(426)** |
| Forfeited | **(917)** | **(563)** | **—** |
| Reinvested | **26** | **43** | **29** |
| **Outstanding, December 31, 2010** | **3 747** | **6 450** | **2 299** |

**Stock-Based Compensation Expense (Recovery)**

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating, selling and general expense in the Consolidated Statements of Earnings:

| ($ millions) | **2010** | 2009 | 2008 |
|---|---|---|---|
| Stock option plans | **53** | 148 | 120 |
| SARs | **27** | 35 | — |
| PSUs | **21** | 30 | (30) |
| RSUs | **90** | 50 | 8 |
| DSUs | **4** | 30 | (51) |
| Total | **195** | 293 | 47 |

## 21. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

### Financial Instruments

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and a portion of non-current accrued liabilities and other.

### (a) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method, with the exception of the portion of debt that is recorded at fair value as part of a fair value hedging relationship. At December 31, 2010, the carrying value of fixed-term debt accounted for under the amortized cost method was $9.7 billion (December 31, 2009 – $10.1 billion) and the fair value at December 31, 2010 was $10.7 billion (December 31, 2009 – $10.7 billion).

### (b) Fair Value of Derivative Financial Instruments

To estimate fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as of December 31, 2010:

| ($ millions) | Level 1 | Level 2 | Level 3 | Total Fair Value |
|---|---|---|---|---|
| Accounts receivable | 11 | 3 | 13 | **27** |
| Accounts payable | (72) | (14) | (7) | **(93)** |
| **Total** | **(61)** | **(11)** | **6** | **(66)** |

**(c) Derivative Financial Instruments – Designated as Part of a Qualifying Hedge Relationship**

***Fair Value Hedges***

The company periodically enters into derivative financial instrument contracts such as interest swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in earnings as an adjustment to interest expense. The swap contracts and underlying debt are recorded at fair value with changes in fair value recognized in interest expense. At December 31, 2010, the company had interest rate swaps designated as fair value hedges expiring in August 2011. The fair value of the swaps, which related to $200 million of its fixed-rate debt, was $8 million as at December 31, 2010 (2009 – $18 million) and was recorded in accounts receivable (2009 – $10 million recorded in accounts receivable and $8 million recorded in other assets). There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the years ended December 31, 2010 and December 31, 2009.

**(d) Other Derivative Financial Instruments**

***Risk Management Derivatives***

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under GAAP, are believed to be economically effective at mitigating exposure to commodity price movements and are a component of Suncor's overall risk management program. These derivative contracts include crude oil, natural gas, refined products and foreign exchange contracts. The earnings impact associated with these contracts for the year ended December 31, 2010, was a gain of $89 million (2009 – a loss of $1.024 billion).

***Energy Trading Derivatives***

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. These energy contracts are comprised of crude oil, refined products and natural gas contracts.

The earnings impact associated with these contracts for the year ended December 31, 2010, was a gain of $81 million (2009 – a loss of $70 million).

**Change in Fair Value of Other Derivative Financial Instruments**

| ($ millions) | Risk Management | Energy Trading | Total |
|---|---|---|---|
| Fair value of contracts at December 31, 2009 | (312) | (47) | (359) |
| Fair value of contracts realized during the period | **236** | **(121)** | **115** |
| Changes in fair value during the period | **89** | **81** | **170** |
| **Fair value of contracts outstanding at December 31, 2010** | **13** | **(87)** | **(74)** |

**Financial Risk Factors**

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's risk management for trading activities which are defined as strategic hedging, optimization trading, marketing and speculative trading. The CRMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls, and is unchanged from the prior year.

**1) Market Risk**

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

### (a) Commodity Price Risk

The company's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and refined product prices. The company's policies permit the use of various financial instruments in managing these price exposures.

Impacts on the company's pre-tax earnings from changes in the fair value of outstanding derivative financial instruments at December 31, 2010 resulting from changes in commodity prices (with all other variables held constant) are disclosed in the following table. This sensitivity analysis is limited to the impact of commodity price changes applied to derivative financial instruments only, and do not represent the impact of a change in the commodity price on the financial results of the company taken as a whole.

**Sensitivity Analysis**

| ($ millions) | December 31, 2010[1] | Change | Pre-tax Earnings |
|---|---|---|---|
| Crude Oil | US$93.37/barrel | | |
| Price increase | | US$1.00/barrel | (4) |
| Price decrease | | US$1.00/barrel | 4 |
| Natural Gas | US$4.99/mcf | | |
| Price increase | | US$0.10/mcf | (4) |
| Price decrease | | US$0.10/mcf | 4 |

(1) Prices represent average futures' prices at December 31, 2010.

### (b) Foreign Currency Exchange Risk

The company is exposed to changes in foreign exchange rates as revenues, capital expenditures, or financial instruments may fluctuate due to changing rates. As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. The company's exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. The effect on the company's financial instruments of a $0.01 change in the US$/Cdn$ exchange rate would change pre-tax earnings by approximately $90 million for the year ended December 31, 2010. The company is also exposed to foreign currency exchange risk from its self-sustaining foreign operations whose functional currency is different from the company's functional currency. The effect on the company's financial instruments of a $0.01 change in the US$/Cdn$ exchange rate would change other comprehensive income by approximately $15 million for the year ended December 31, 2010.

### (c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to revolving-term debt (commercial paper, bankers' acceptances and LIBOR loans).

To manage the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. This floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk.

The proportion of floating interest rate exposure inclusive of interest rate swaps at December 31, 2010 was 18% of total debt outstanding (December 31, 2009 – 25%). The weighted-average interest rate on total debt for the year ending December 31, 2010 was 5.7% (December 31, 2009 – 5.6%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. If the interest rates applicable to floating rate instruments were to have increased by 1%, it is estimated that the company's pre-tax earnings for the year ended December 31, 2010 would decrease by approximately $22 million.

### 2) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The company believes that it has access to sufficient capital through internally generated cash flows and external sources (bank credit markets and debt capital markets), and to undrawn committed borrowing facilities to meet current spending forecasts.

Surplus cash is invested into a range of short-dated money market securities and the company seeks to ensure the security and liquidity of those investments by only investing in high credit quality government or corporate securities. Diversification of these investments is supported through maintaining counterparty credit limits.

The following table shows the timing of cash outflows relating to trade and other payables and debt.

| | **December 31, 2010** | | December 31, 2009 | |
|---|---|---|---|---|
| ($ millions) | **Trade and other payables (1)** | **Debt (2)** | Trade and other payables (1) | Debt (2) |
| Within one year | **6 942** | **3 127** | 6 529 | 3 796 |
| 1 to 3 years | **359** | **1 560** | 653 | 1 811 |
| 3 to 5 years | **32** | **1 611** | — | 1 591 |
| Over 5 years | **—** | **17 338** | — | 18 900 |
| Total | **7 333** | **23 636** | 7 182 | 26 098 |

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Debt includes short-term debt, long-term debt, capital leases and interest payments on fixed-term debt and commercial paper.

### 3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company has a credit policy that is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2010, substantially all of the company's trade receivables were current, and there were no counterparties that individually constituted more than 10% of the outstanding balance.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2010, the company's exposure was $27 million (December 31, 2009 – $231 million).

## 22. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income (loss), net of income taxes, are as follows:

| As at December 31 ($ millions) | **2010** | 2009 |
|---|---|---|
| Unrealized foreign currency translation adjustment | **(698)** | (248) |
| Unrealized gains on derivative hedging activities | **14** | 15 |
| Total | **(684)** | (233) |

## 23. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a conservative balance sheet, which supports a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is monitored through net debt to cash flow from operations[1] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2010 and 2009.

The company's strategy during 2010, which was unchanged from 2009, was to maintain the measure set out in the following schedule. The company believes that achieving this capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

| At December 31, ($ millions) | Capital Measure Target | **2010** | 2009 |
|---|---|---|---|
| Components of ratios | | | |
| Short-term debt | | **2** | 2 |
| Current portion of long-term debt | | **518** | 25 |
| Long-term debt | | **11 669** | 13 855 |
| Total debt | | **12 189** | 13 882 |
| Less: Cash and equivalents | | **1 077** | 505 |
| Net debt | | **11 112** | 13 377 |
| Shareholders' equity | | **36 721** | 34 111 |
| Total capitalization (total debt plus shareholders' equity) | | **48 910** | 47 993 |
| Cash flow from operations (1) | | **6 656** | 2 799 |
| Net debt to cash flow from operations | <2.0 times | **1.7** | 4.8 |
| Total debt to total debt plus shareholders' equity | | **25%** | 29% |

(1) Cash flow from operations is expressed before changes in non-cash working capital.

## 24. COMMITMENTS, CONTINGENCIES, AND GUARANTEES

### (a) Commitments

| ($ millions) | Pipeline Capacity and Energy Services (1) | Operating Leases |
|---|---|---|
| 2011 | 759 | 330 |
| 2012 | 667 | 250 |
| 2013 | 726 | 227 |
| 2014 | 692 | 170 |
| 2015 | 642 | 119 |
| Later years | 7 822 | 852 |
| Total | 11 308 | 1 948 |

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the U.S. Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company.

In addition to the operating commitments quantified in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

### Crude Oil

At December 31, 2010, Suncor had purchase commitments relating to crude oil predominately for refinery supply. Crude oil commitments consisted of market price evergreen contracts for a total volume of 289,000 barrels per day of crude oil, of which most have industry standard thirty-day cancellation clauses.

### Natural Gas

At December 31, 2010, Suncor had purchase commitments relating to natural gas for physical trading. Natural gas commitments consist of fixed price contracts with a total volume of 13 million GJ within a price range of $3.22–$5.20 per GJ and having terms extending to October 2012, as well as market price contracts for a total volume of 134 million GJ with terms extending to October 2015.

**Refined Products**

At December 31, 2010, Suncor's significant purchase commitments relating to finished products at its refineries consisted of market price contracts for a total volume of 4,648 million litres and having terms extending to 2017.

**(b) Contingencies**

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Estimates of asset retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company reduces exposure to some operational risks by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries third-party property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2010, Suncor's insurance program includes a coverage limit of up to US$1.3 billion for oil sands risks, up to US$1.25 billion for offshore risks and up to US$600 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume caps. The company also has third-party primary property insurance for US$250 million that covers all of Suncor's assets.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

**(c) Guarantees**

In certain of the retail licensee arrangements, the company has provided loan guarantees. The company's maximum exposure to loss from these arrangements is not expected to be significant.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

## 25. JOINT VENTURE WITH TOTAL

On December 17, 2010, Suncor announced that it plans to enter into a joint venture with Total E&P Canada Ltd (Total). The two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction of the Voyageur upgrader.

Total will acquire a 49% interest in Suncor's Voyageur upgrader, and an additional 19.2% in the Fort Hills project, reducing Suncor's interest from 60% to 40.8%. In return, Suncor will acquire a 36.75% interest in the Joslyn project and receive cash consideration of approximately $1.75 billion.

The agreement is subject to certain regulatory and other approvals, with closing targeted in the first quarter of 2011. The development of the Fort Hills and Joslyn oil sands mining projects, as well as the continued construction of the Voyageur upgrader, is subject to approval by all of the partners in these ventures and by Suncor's Board of Directors.

## 26. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on net earnings and comprehensive income as reported:

| ($ millions) | Notes | 2010 | 2009 | 2008 |
|---|---|---|---|---|
| Net earnings as reported, Canadian GAAP | | **3 571** | 1 146 | 2 137 |
| Adjustments | | | | |
| Transaction costs and provisions | (a) | **(68)** | (302) | — |
| Stock-based compensation expense | (b) | **(13)** | 41 | (7) |
| Energy supply and trading activities (inventory valuation) | (e) | **4** | (47) | — |
| Income taxes | | **20** | 80 | 1 |
| Net earnings, U.S. GAAP | | **3 514** | 918 | 2 131 |
| Pension and post-retirement obligation, net of income taxes of $52 (2009 – $22; 2008 – $20) | (c) | **(168)** | 43 | 43 |
| Other comprehensive income (loss) items | | **(451)** | (330) | 350 |
| Comprehensive income, U.S. GAAP | | **2 895** | 631 | 2 524 |

| (dollars) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net earnings per common share, U.S. GAAP | | | |
| Basic | **2.25** | 0.77 | 2.29 |
| Diluted | **2.23** | 0.76 | 2.26 |

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

| | | **December 31, 2010** | | December 31, 2009 | |
|---|---|---|---|---|---|
| | Notes | **As Reported** | **U.S. GAAP** | As Reported | U.S. GAAP |
| Current assets | (a,e) | **10 513** | **10 544** | 8 331 | 8 318 |
| Property, plant and equipment, net | | **55 290** | **55 290** | 54 198 | 54 198 |
| Other assets | (d) | **451** | **510** | 491 | 554 |
| Goodwill | (a) | **3 201** | **5 762** | 3 201 | 5 762 |
| Future income taxes | | **56** | **139** | 193 | 193 |
| Assets of discontinued operations | | **658** | **658** | 3 332 | 3 332 |
| Total assets | | **70 169** | **72 903** | 69 746 | 72 357 |
| Current liabilities | (a,b) | **8 526** | **8 608** | 7 848 | 7 881 |
| Long-term borrowings | (d) | **11 669** | **11 728** | 13 855 | 13 918 |
| Accrued liabilities and other | (b,c) | **4 154** | **4 462** | 4 372 | 4 429 |
| Future income taxes | | **8 615** | **8 620** | 8 367 | 8 320 |
| Liabilities of discontinued operations | | **484** | **484** | 1 193 | 1 193 |
| Share capital | (b) | **20 188** | **23 047** | 20 053 | 22 908 |
| Contributed surplus | (b) | **505** | **521** | 526 | 546 |
| Retained earnings | (a,b,e) | **16 712** | **16 321** | 13 765 | 13 431 |
| Accumulated other comprehensive income (loss) | (c) | **(684)** | **(888)** | (233) | (269) |
| Total liabilities and shareholders' equity | | **70 169** | **72 903** | 69 746 | 72 357 |

Certain prior period comparative figures have been reclassified to conform to the current presentation.

### (a) Business Combination with Petro-Canada

Under U.S. GAAP, the total purchase price for the acquisition was $22.225 billion. U.S. GAAP requires the 621.1 million Suncor shares offered as consideration to complete the merger to be valued at $34.84 per share, which was the Suncor share price as at the transaction close date of August 1, 2009. Under Canadian GAAP the share price is that value as at the merger announcement date. In addition, transaction costs of $124 million (net of income taxes of $43 million) are not permitted to be included in consideration under U.S. GAAP, and are expensed instead.

Under Canadian GAAP, the transaction costs were netted against cash acquired in the business combination and presented as part of cash flow from investing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP, the $124 million of transaction costs would be included in net earnings and thus be presented as a reduction in cash flow from operating activities.

The fair value of current liabilities assumed by Suncor in the business combination under Canadian GAAP included $160 million (net of income taxes of $56 million) for provisions for severance and other costs associated with exiting certain activities of Petro-Canada that cannot be recognized at the time of the merger under U.S. GAAP and must be expensed as incurred. At December 31, 2010, $128 million, net of income taxes of $45 million, of amounts related to these provisions had been incurred (2009 – $99 million, net of income taxes of $36 million). During 2010, the original provision set up under Canadian GAAP was reduced by $22 million (net of income taxes of $8 million) as a result of an adjustment made to the cost estimate for the Montreal coker provision. At December 31, 2010, $4 million, net of income taxes of $2 million, related to provisions remains in current liabilities under U.S. GAAP (2009 – $12 million, net of income taxes of $4 million).

As per note (b), under U.S. GAAP stock-based compensation awards recognized as liabilities are measured using different methods than Canadian GAAP. At August 1, 2009, the value of CPAs, SARs, RSUs and PSUs calculated using methods prescribed by U.S. GAAP was $126 million (net of income taxes of $43 million) greater than the value calculated using methods prescribed under Canadian GAAP.

As a result of these differences in accounting for this business combination, the resulting value for goodwill under U.S. GAAP is $5,762 million, of which $5,474 million would be allocated to the Oil Sands segment and the remaining $288 million would be allocated to the Refining and Marketing segment.

**(b) Stock-Based Compensation**

Under Canadian GAAP, the company's stock options with a cash payment alternative (CPAs), stock appreciation rights (SARs), performance share units (PSUs) and restricted share units (RSUs) are measured using an intrinsic approach, which is a fair-value technique not permitted under U.S. GAAP. For U.S. GAAP, the company's CPAs, SARs and RSUs have been measured at fair value using the Black-Scholes option-pricing model, while PSUs have been measured using a Monte Carlo Simulation approach to determine fair value. The impact on net earnings for the year ended December 31, 2010 is additional expense of $10 million, net of income taxes of $3 million (2009 – recovery of previously recognized expense of $31 million, net of income taxes of $10 million; 2008 – expense of $2 million, net of income taxes of $1 million).

Under Canadian GAAP, compensation expense related to common share options granted prior to January 1, 2003 (pre-2003 options) is not recognized in the Consolidated Statements of Earnings. U.S. GAAP requires the recognition of expense related to the company's pre-2003 options. There was no additional compensation expense to recognize in 2010 or 2009, as the remaining expense of $4 million for pre-2003 options was recognized in 2008. There was no impact on income taxes.

**(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans**

U.S. GAAP requires the company recognize the over funded or under funded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet, with changes to funded status in the year recorded through comprehensive income, net of income taxes. Canadian GAAP currently does not require the company to recognize the funded status of these plans in the Consolidated Balance Sheets. In 2010, other comprehensive income under U.S. GAAP would decrease by $168 million, net of income taxes of $52 million (2009 – increase by $43 million, net of income taxes of $22 million; 2008 – increase by $43 million, net of income taxes of $20 million).

**(d) Deferred Financing Costs**

Effective January 1, 2007, under Canadian GAAP, deferred financing costs on long-term debt are included in the carrying value of the related debt. Under U.S. GAAP, these costs are recorded as a deferred charge. As a result, $59 million would have been reclassified from long-term debt to other assets at December 31, 2010 (December 31, 2009 – $63 million).

**(e) Inventory**

U.S. GAAP requires inventory to be measured at the lower of cost or net realizable value and does not permit the measurement of held for trading inventories at fair value less costs to sell. As a result, the value of energy trading inventories at December 31, 2010 is lower by $40 million (2009 — $47 million). Earnings for the twelve months ended December 31, 2010 would increase by $3 million, net of income taxes of $1 million, as a result of not recognizing fair value changes (2009 — decrease earnings by $32 million, net of income taxes of $15 million).

**(f) Cash Flow Information**

Other than described in note (a), the application of U.S. GAAP would not have a material effect on cash flow from total operating, investing, or financing activities on the Consolidated Statements of Cash Flows.

**Recently Adopted Accounting Standards**

Effective January 1, 2010, the company adopted amendments to Topic 810 "Consolidations". The adoption of these amendments had no impact on net earnings or financial position.

# QUARTERLY SUMMARY (unaudited)

## FINANCIAL DATA [1]

| ($ millions, except per share amounts) | For the Quarter Ended Mar 31 2010 | June 30 2010 | Sept 30 2010 | Dec 31 2010 | Total Year 2010 | For the Quarter Ended Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 | Total Year 2009 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from continuing operations** | **6 946** | **8 979** | **8 636** | **9 789** | **34 350** | 4 607 | 4 748 | 8 257 | 7 236 | 24 848 |
| **Net earnings (loss) from continuing operations** | | | | | | | | | | |
| Oil Sands | **76** | **517** | **412** | **487** | **1 492** | (110) | (307) | 738 | 236 | 557 |
| Natural Gas | **23** | **(68)** | **(167)** | **(65)** | **(277)** | (10) | (23) | (97) | (55) | (185) |
| International and Offshore | **209** | **217** | **236** | **452** | **1 114** | — | — | 93 | 230 | 323 |
| Refining and Marketing | **139** | **138** | **152** | **372** | **801** | 112 | 99 | 45 | 151 | 407 |
| Corporate, Energy Trading and Eliminations | **17** | **(486)** | **(24)** | **51** | **(442)** | (181) | 185 | 186 | (86) | 104 |
| | **464** | **318** | **609** | **1 297** | **2 688** | (189) | (46) | 965 | 476 | 1 206 |
| **Per common share** | | | | | | | | | | |
| Net earnings (loss) from continuing operations | | | | | | | | | | |
| – basic | **0.30** | **0.20** | **0.39** | **0.83** | **1.72** | (0.20) | (0.05) | 0.72 | 0.30 | 1.01 |
| – diluted | **0.30** | **0.20** | **0.39** | **0.82** | **1.71** | (0.20) | (0.05) | 0.71 | 0.30 | 1.00 |
| Net earnings (loss) | | | | | | | | | | |
| – basic | **0.46** | **0.31** | **0.65** | **0.87** | **2.29** | (0.20) | (0.06) | 0.69 | 0.29 | 0.96 |
| – diluted | **0.46** | **0.31** | **0.65** | **0.86** | **2.27** | (0.20) | (0.06) | 0.68 | 0.29 | 0.95 |
| Cash dividends | **0.10** | **0.10** | **0.10** | **0.10** | **0.40** | 0.05 | 0.05 | 0.10 | 0.10 | 0.30 |
| **Cash flow from (used in) operations from continuing operations** | | | | | | | | | | |
| Oil Sands | **262** | **933** | **779** | **795** | **2 769** | 480 | 174 | 242 | 355 | 1 251 |
| Natural Gas | **132** | **82** | **56** | **50** | **320** | 35 | 33 | 39 | 70 | 177 |
| International and Offshore | **542** | **517** | **568** | **885** | **2 512** | — | — | 238 | 500 | 738 |
| Refining and Marketing | **328** | **263** | **326** | **619** | **1 536** | 205 | 194 | 264 | 258 | 921 |
| Corporate, Energy Trading and Eliminations | **(314)** | **(196)** | **(244)** | **(219)** | **(973)** | 63 | (115) | (299) | (302) | (653) |
| | **950** | **1 599** | **1 485** | **2 130** | **6 164** | 783 | 286 | 484 | 881 | 2 434 |

(1) The comparative financial data includes the results of post-merger Suncor from August 1, 2009. As such, the amounts reflect results of the post-merger Suncor from August 1, 2009 together with the results of lergacy Suncor only from January 1, 2009 through July 31, 2009.

## QUARTERLY SUMMARY (unaudited) (continued)

### OPERATING DATA

| | For the Quarter Ended Mar 31 2010 | June 30 2010 | Sept 30 2010 | Dec 31 2010 | Total Year 2010 | For the Quarter Ended Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 | Total Year 2009 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OIL SANDS** | | | | | | | | | | |
| **Production** (kbpd) | | | | | | | | | | |
| Total production (excluding Syncrude) | **202.3** | **295.5** | **306.6** | **325.9** | **283.0** | 278.0 | 301.0 | 305.3 | 278.9 | 290.6 |
| Firebag (kbpd of bitumen) | **55.7** | **55.7** | **50.4** | **52.9** | **53.6** | 42.4 | 48.3 | 54.3 | 51.1 | 49.1 |
| Mackay River (kbpd of bitumen) | **31.8** | **32.5** | **28.8** | **32.9** | **31.5** | — | — | 26.5** | 31.7 | 29.7** |
| Syncrude | **32.3** | **38.9** | **31.7** | **37.9** | **35.2** | — | — | 37.4** | 39.3 | 38.5** |
| **Sales** (kbpd) (excluding Syncrude) | | | | | | | | | | |
| Light sweet crude oil | **61.0** | **99.0** | **84.5** | **84.5** | **82.3** | 108.8 | 99.4 | 89.6 | 100.8 | 99.6 |
| Diesel | **12.9** | **30.7** | **25.8** | **12.2** | **20.4** | 22.8 | 25.3 | 36.9 | 31.4 | 29.1 |
| Light sour crude oil | **80.5** | **143.1** | **165.8** | **189.8** | **145.2** | 102.7 | 150.5 | 146.8 | 142.4 | 135.7 |
| Bitumen | **42.3** | **37.4** | **21.2** | **24.9** | **31.4** | 9.1 | 10.5 | 14.3 | 13.0 | 11.8 |
| **Total sales** | **196.7** | **310.2** | **297.3** | **311.4** | **279.3** | 243.4 | 285.7 | 287.6 | 287.6 | 276.2 |
| **Average sales price** (1) (dollars per barrel) (excluding Syncrude) | | | | | | | | | | |
| Light sweet crude oil* | **80.84** | **77.55** | **75.49** | **83.02** | **79.03** | 54.64 | 65.83 | 71.99 | 77.71 | 67.26 |
| Other (diesel, light sour crude oil and bitumen)* | **69.53** | **68.53** | **66.39** | **70.29** | **68.63** | 48.80 | 62.71 | 67.51 | 72.93 | 64.18 |
| Total * | **73.03** | **71.41** | **68.97** | **73.75** | **71.69** | 51.46 | 63.79 | 68.91 | 74.61 | 65.29 |
| Total | **70.21** | **69.79** | **67.53** | **70.95** | **69.58** | 59.45 | 59.34 | 62.01 | 65.42 | 61.66 |
| Syncrude average sales price (1) (dollars per barrel) | **83.21** | **77.32** | **78.83** | **84.40** | **80.93** | — | — | 75.17 | 78.81 | 77.36 |
| **Operating costs – Total operations (excluding Syncrude)** (dollars per barrel) | | | | | | | | | | |
| Cash costs | **46.50** | **31.70** | **32.45** | **34.35** | **35.30** | 30.65 | 29.65 | 30.65 | 35.10 | 31.50 |
| Natural gas | **5.40** | **3.55** | **1.10** | **2.30** | **2.85** | 3.00 | 1.65 | 1.55 | 3.40 | 2.40 |
| Imported bitumen | **2.95** | **0.65** | **0.05** | **0.05** | **0.70** | 0.05 | — | 0.05 | 0.20 | 0.05 |
| **Cash operating costs** (2) | **54.85** | **35.90** | **33.60** | **36.70** | **38.85** | 33.70 | 31.30 | 32.25 | 38.70 | 33.95 |
| Project start-up costs | **0.55** | **0.55** | **0.75** | **0.95** | **0.70** | 0.65 | 0.35 | 0.45 | 0.50 | 0.45 |
| **Total cash operating costs** (3) | **55.40** | **36.45** | **34.35** | **37.65** | **39.55** | 34.35 | 31.65 | 32.70 | 39.20 | 34.40 |
| Depreciation, depletion and amortization | **12.65** | **15.35** | **9.00** | **8.80** | **11.25** | 7.30 | 7.20 | 7.60 | 10.00 | 8.00 |
| **Total operating costs** (4) | **68.05** | **51.80** | **43.35** | **46.45** | **50.80** | 41.65 | 38.85 | 40.30 | 49.20 | 42.40 |
| **Operating costs – Syncrude** (dollars per barrel)*** | | | | | | | | | | |
| Cash costs | **39.60** | **28.75** | **39.20** | **32.85** | **34.70** | — | — | 29.50 | 29.65 | 29.60 |
| Natural gas | **4.50** | **2.85** | **2.75** | **3.05** | **3.25** | — | — | 2.10 | 3.45 | 2.90 |
| **Cash operating costs** (2) | **44.10** | **31.60** | **41.95** | **35.90** | **37.95** | — | — | 31.60 | 33.10 | 32.50 |
| Project start-up costs | **—** | **—** | **—** | **—** | **—** | — | — | — | — | — |
| **Total cash operating costs** (3) | **44.10** | **31.60** | **41.95** | **35.90** | **37.95** | — | — | 31.60 | 33.10 | 32.50 |
| Depreciation, depletion and amortization | **13.70** | **11.35** | **14.85** | **9.65** | **12.20** | — | — | 12.70 | 11.80 | 12.15 |
| **Total operating costs** (4) | **57.80** | **42.95** | **56.80** | **45.55** | **50.15** | — | — | 44.30 | 44.90 | 44.65 |
| **Operating costs – In situ bitumen production only** (dollars per barrel) | | | | | | | | | | |
| Cash costs | **12.30** | **13.65** | **17.15** | **16.50** | **14.85** | 15.25 | 16.40 | 13.25 | 14.25 | 14.55 |
| Natural gas | **7.05** | **5.05** | **5.25** | **4.80** | **5.55** | 7.90 | 5.30 | 4.30 | 6.05 | 5.70 |
| **Cash operating costs** (5) | **19.35** | **18.70** | **22.40** | **21.30** | **20.40** | 23.15 | 21.70 | 17.55 | 20.30 | 20.25 |
| Project start-up costs | **0.95** | **1.45** | **2.50** | **3.35** | **2.05** | 2.30 | 1.45 | 0.65 | 1.35 | 1.35 |
| **Total cash operating costs** (6) | **20.30** | **20.15** | **24.90** | **24.65** | **22.45** | 25.45 | 23.15 | 18.20 | 21.65 | 21.60 |
| Depreciation, depletion and amortization | **5.05** | **4.70** | **5.90** | **5.20** | **5.20** | 6.95 | 6.00 | 5.95 | 6.65 | 6.35 |
| **Total operating costs** (7) | **25.35** | **24.85** | **30.80** | **29.85** | **27.65** | 32.40 | 29.15 | 24.15 | 28.30 | 27.95 |

Footnotes, definitions and abbreviations, see page 100.

## QUARTERLY SUMMARY (unaudited) (continued)

**OPERATING DATA** (continued)

| | For the Quarter Ended | | | | Total Year | For the Quarter Ended | | | | Total Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2010** | **June 30 2010** | **Sept 30 2010** | **Dec 31 2010** | **2010** | Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 | 2009 |
| **NATURAL GAS** | | | | | | | | | | |
| **Gross production** | | | | | | | | | | |
| Natural gas (mmcf/d) | | | | | | | | | | |
| Continuing operations | **419** | **398** | **380** | **399** | **399** | 140 | 145 | 335 | 424 | 262 |
| Discontinued operations | **230** | **138** | **120** | **8** | **123** | 60 | 47 | 182 | 250 | 135 |
| Natural gas liquids and crude oil (kbpd) | | | | | | | | | | |
| Continuing operations | **6.2** | **5.5** | **5.4** | **4.9** | **5.5** | 1.1 | 1.0 | 4.8 | 6.2 | 3.3 |
| Discontinued operations | **7.8** | **2.8** | **2.2** | **0.2** | **3.3** | 2.0 | 2.2 | 5.9 | 8.8 | 4.8 |
| Total gross production (mmcfe/d) | | | | | | | | | | |
| Continuing operations | **456** | **431** | **412** | **429** | **432** | 147 | 151 | 363 | 461 | 282 |
| Discontinued operations | **277** | **155** | **134** | **9** | **143** | 72 | 60 | 218 | 303 | 164 |
| **Average sales price from continuing operations** (1) | | | | | | | | | | |
| Natural gas (dollars per mcf) | **5.34** | **3.42** | **3.66** | **3.39** | **3.99** | 5.42 | 3.26 | 2.70 | 3.92 | 3.63 |
| Natural gas (dollars per mcf) * | **5.34** | **3.42** | **3.66** | **3.39** | **3.99** | 5.41 | 3.23 | 2.68 | 3.91 | 3.62 |
| Natural gas liquids and crude oil (dollars per barrel) | **74.71** | **82.82** | **68.03** | **71.56** | **77.37** | 45.08 | 40.04 | 58.31 | 65.74 | 59.41 |
| **INTERNATIONAL AND OFFSHORE**** | | | | | | | | | | |
| **East Coast Canada** | | | | | | | | | | |
| **Production** (kbpd) | | | | | | | | | | |
| Terra Nova | **29.6** | **27.2** | **17.2** | **19.0** | **23.2** | — | — | 16.0 | 24.0 | 20.8 |
| Hibernia | **30.2** | **30.1** | **32.3** | **30.9** | **30.9** | — | — | 28.5 | 26.3 | 27.2 |
| White Rose | **14.8** | **13.3** | **16.8** | **13.0** | **14.5** | — | — | 5.1 | 13.3 | 10.0 |
| **Total production** | **74.6** | **70.6** | **66.3** | **62.9** | **68.6** | — | — | 49.6 | 63.6 | 58.0 |
| **Average sales price** (1) (dollars per barrel) | **78.69** | **76.88** | **78.78** | **87.12** | **80.20** | — | — | 75.22 | 77.71 | 76.86 |
| **International** | | | | | | | | | | |
| **Production** (kboe/d) | | | | | | | | | | |
| *North Sea* | | | | | | | | | | |
| Buzzard | **58.6** | **49.3** | **58.6** | **55.6** | **55.5** | — | — | 29.4 | 59.9 | 47.8 |
| Discontinued operations | **27.5** | **22.7** | **25.2** | **18.7** | **23.5** | — | — | 25.2 | 31.1 | 28.7 |
| Total North Sea | **86.1** | **72.0** | **83.8** | **74.3** | **79.0** | — | — | 54.6 | 91.0 | 76.5 |
| *Other International* | | | | | | | | | | |
| Libya | **35.4** | **35.4** | **35.4** | **34.7** | **35.2** | — | — | 42.7 | 26.0 | 32.6 |
| Syria**** | **—** | **12.8** | **16.5** | **16.9** | **11.6** | — | — | — | — | — |
| Discontinued operations | **11.7** | **11.1** | **4.2** | **—** | **6.7** | — | — | 11.3 | 12.0 | 11.7 |
| Total Other International | **47.1** | **59.3** | **56.1** | **51.6** | **53.5** | — | — | 54.0 | 38.0 | 44.3 |
| **Total production** | **133.2** | **131.3** | **139.9** | **125.9** | **132.5** | — | — | 108.6 | 129.0 | 120.8 |
| **Average sales price from continuing operations** (1) (dollars per boe) | | | | | | | | | | |
| Buzzard | **72.36** | **78.57** | **75.60** | **85.46** | **77.91** | — | — | 72.02 | 68.71 | 69.53 |
| Other International | **73.40** | **76.14** | **74.90** | **83.06** | **78.07** | — | — | 75.60 | 79.06 | 77.53 |
| **Total International and Offshore Production** (kboe/d) | **207.8** | **201.9** | **206.2** | **188.8** | **201.1** | — | — | 158.2 | 192.6 | 178.8 |

Footnotes, definitions and abbreviations, see page 100.

## QUARTERLY SUMMARY (unaudited) (continued)

### OPERATING DATA (continued)

| | For the Quarter Ended Mar 31 2010 | June 30 2010 | Sept 30 2010 | Dec 31 2010 | Total Year 2010 | For the Quarter Ended Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 | Total Year 2009 |
|---|---|---|---|---|---|---|---|---|---|---|
| **REFINING AND MARKETING** | | | | | | | | | | |
| **Eastern North America** | | | | | | | | | | |
| **Refined product sales** (thousands of $m^3$/d) | | | | | | | | | | |
| Transportation fuels | | | | | | | | | | |
| Gasoline | **21.0** | **22.5** | **22.5** | **22.9** | **22.2** | 8.2 | 8.7 | 18.3 | 23.0 | 14.6 |
| Distillate | **12.3** | **12.5** | **11.7** | **13.7** | **12.4** | 5.1 | 5.4 | 10.3 | 13.9 | 8.8 |
| Total transportation fuel sales | **33.3** | **35.0** | **34.2** | **36.6** | **34.6** | 13.3 | 14.1 | 28.6 | 36.9 | 23.4 |
| Petrochemicals | **2.2** | **2.8** | **2.5** | **2.4** | **2.5** | 1.0 | 1.0 | 1.7 | 1.2 | 0.8 |
| Asphalt | **1.8** | **3.0** | **3.7** | **2.4** | **2.7** | 0.8 | 0.7 | 2.4 | 2.0 | 1.5 |
| Other | **4.3** | **6.0** | **6.0** | **5.3** | **5.5** | 0.5 | 1.0 | 3.0 | 1.9 | 2.0 |
| **Total refined product sales** | **41.6** | **46.8** | **46.4** | **46.7** | **45.3** | 15.6 | 16.8 | 35.7 | 42.0 | 27.7 |
| **Crude oil supply and refining** | | | | | | | | | | |
| Processed at refineries (thousands of $m^3$/d) | **31.0** | **30.6** | **30.7** | **29.7** | **30.5** | 11.3 | 11.8 | 25.5 | 28.3 | 29.6** |
| Utilization of refining capacity (%) | **91** | **90** | **90** | **87** | **89** | 84 | 87 | 94 | 83 | 87 |
| **Western North America** | | | | | | | | | | |
| **Refined product sales** (thousands of $m^3$/d) | | | | | | | | | | |
| Transportation fuels | | | | | | | | | | |
| Gasoline | **18.1** | **19.2** | **19.9** | **18.3** | **18.9** | 8.2 | 8.9 | 16.1 | 18.4 | 13.0 |
| Distillate | **16.9** | **16.3** | **17.4** | **23.2** | **18.5** | 5.4 | 5.0 | 11.8 | 15.6 | 9.5 |
| Total transportation fuel sales | **35.0** | **35.5** | **37.3** | **41.5** | **37.4** | 13.6 | 13.9 | 27.9 | 34.0 | 22.5 |
| Asphalt | **1.2** | **1.5** | **1.5** | **0.9** | **1.3** | 1.2 | 1.4 | 1.7 | 0.9 | 1.3 |
| Other | **4.4** | **5.2** | **3.7** | **2.0** | **3.8** | 1.0 | 1.8 | 4.6 | 6.0 | 3.4 |
| **Total refined product sales** | **40.6** | **42.2** | **42.5** | **44.4** | **42.5** | 15.8 | 17.1 | 34.2 | 40.9 | 27.2 |
| **Crude oil supply and refining** | | | | | | | | | | |
| Processed at refineries (thousands of $m^3$/d) | **33.5** | **31.7** | **36.6** | **36.5** | **34.6** | 14.2 | 15.6 | 27.8 | 33.4 | 33.6** |
| Utilization of refining capacity (%) | **92** | **87** | **101** | **101** | **95** | 96 | 106 | 100 | 96 | 97 |

Footnotes, definitions and abbreviations, see page 100.

## QUARTERLY SUMMARY (unaudited) (continued)

**OPERATING DATA** (continued)

| | For the Quarter Ended | | | | Total Year | For the Quarter Ended | | | | Total Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2010** | **June 30 2010** | **Sept 30 2010** | **Dec 31 2010** | **2010** | Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 | 2009 |
| **NETBACKS – Continuing Operations** | | | | | | | | | | |
| **Natural Gas** (dollars per mcfe) | | | | | | | | | | |
| Average price realized [8] | **6.23** | **5.06** | **4.76** | **4.40** | **5.16** | 5.87 | 3.56 | 3.69 | 5.02 | 4.50 |
| Royalties | **(0.91)** | **(0.06)** | **(0.50)** | **(0.45)** | **(0.49)** | (0.98) | (0.88) | (0.18) | (0.71) | (0.37) |
| Transportation costs | **(0.37)** | **(0.55)** | **(0.39)** | **(0.33)** | **(0.41)** | (0.32) | (0.28) | (0.43) | (0.45) | (0.41) |
| Operating costs | **(1.30)** | **(1.55)** | **(1.53)** | **(1.71)** | **(1.52)** | (1.55) | (1.27) | (1.37) | (1.43) | (1.39) |
| Operating netback | **3.65** | **2.90** | **2.34** | **1.91** | **2.74** | 3.02 | 1.13 | 1.71 | 2.43 | 2.33 |
| **International and Offshore** | | | | | | | | | | |
| **East Coast Canada** (dollars per barrel) | | | | | | | | | | |
| Average price realized [8] | **80.79** | **78.99** | **81.06** | **89.35** | **82.38** | — | — | 77.85 | 79.69 | 79.07 |
| Royalties | **(28.78)** | **(28.45)** | **(25.49)** | **(29.17)** | **(27.99)** | — | — | (21.02) | (25.26) | (23.82) |
| Transportation costs | **(2.10)** | **(2.11)** | **(2.28)** | **(2.23)** | **(2.18)** | — | — | (2.63) | (1.98) | (2.21) |
| Operating costs | **(6.38)** | **(6.08)** | **(6.80)** | **(7.57)** | **(6.68)** | — | — | (10.36) | (5.63) | (7.24) |
| Operating netback | **43.53** | **42.35** | **46.49** | **50.38** | **45.53** | — | — | 43.84 | 46.82 | 45.80 |
| **North Sea – Buzzard** (dollars per barrel) | | | | | | | | | | |
| Average price realized [8] | **74.19** | **80.35** | **77.43** | **87.30** | **79.73** | — | — | 75.49 | 70.38 | 71.64 |
| Transportation costs | **(1.83)** | **(1.78)** | **(1.83)** | **(1.84)** | **(1.82)** | — | — | (3.47) | (1.67) | (2.11) |
| Operating costs | **(3.09)** | **(3.57)** | **(2.90)** | **(2.80)** | **(3.07)** | — | — | (2.82) | (2.90) | (2.88) |
| Operating netback | **69.27** | **75.00** | **72.70** | **82.66** | **74.84** | — | — | 69.20 | 65.81 | 66.65 |
| **Other International** (dollars per boe) | | | | | | | | | | |
| Average price realized [8] | **73.92** | **76.61** | **75.24** | **82.74** | **78.30** | — | — | 76.02 | 79.97 | 78.19 |
| Royalties | **(43.28)** | **(36.99)** | **(32.06)** | **(18.37)** | **(35.06)** | — | — | (46.46) | (32.12) | (39.88) |
| Transportation costs | **(0.52)** | **(0.47)** | **(0.34)** | **0.32** | **(0.23)** | — | — | (0.42) | (0.91) | (0.66) |
| Operating costs | **(3.29)** | **(7.40)** | **(4.72)** | **(6.38)** | **(5.60)** | — | — | (1.79) | (5.12) | (3.39) |
| Operating netback | **26.83** | **31.75** | **38.12** | **58.31** | **37.41** | — | — | 27.35 | 41.82 | 34.26 |

Footnotes, definitions and abbreviations, see page 100.

# FIVE-YEAR FINANCIAL SUMMARY (unaudited)

| ($ millions) | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **Revenues from continuing operations** | | | | | |
| Oil Sands | **9 423** | 6 539 | 8 639 | 6 175 | 6 457 |
| Natural Gas | **734** | 423 | 364 | 284 | 313 |
| International and Offshore | **4 323** | 1 217 | — | — | — |
| Refining and Marketing | **21 062** | 11 851 | 9 258 | 8 220 | 7 174 |
| Corporate and eliminations | **(1 192)** | 4 818 | 10 185 | 2 492 | 894 |
| | **34 350** | 24 848 | 28 446 | 17 171 | 14 838 |
| **Net earnings (loss) from continuing operations** | | | | | |
| Oil Sands | **1 492** | 557 | 2 875 | 2 474 | 2 775 |
| Natural Gas | **(277)** | (185) | 34 | 7 | 78 |
| International and Offshore | **1 114** | 323 | — | — | — |
| Refining and Marketing | **801** | 407 | (22) | 406 | 227 |
| Corporate and eliminations | **(442)** | 104 | (805) | 78 | (139) |
| | **2 688** | 1 206 | 2 082 | 2 965 | 2 941 |
| **Cash flow from (used in) operations** | | | | | |
| Oil Sands | **2 769** | 1 251 | 3 507 | 3 165 | 3 902 |
| Natural Gas | **445** | 329 | 367 | 251 | 279 |
| International and Offshore | **2 879** | 951 | — | — | — |
| Refining and Marketing | **1 536** | 921 | 220 | 660 | 422 |
| Corporate and eliminations | **(973)** | (653) | (37) | (39) | (57) |
| | **6 656** | 2 799 | 4 057 | 4 037 | 4 546 |
| **Capital and exploration expenditures** | | | | | |
| Oil Sands | **3 709** | 2 831 | 7 413 | 4 566 | 2 463 |
| Natural Gas | **178** | 320 | 342 | 537 | 458 |
| International and Offshore | **1 096** | 666 | — | — | — |
| Refining and Marketing | **667** | 380 | 207 | 351 | 747 |
| Corporate | **360** | 70 | 58 | 175 | 27 |
| | **6 010** | 4 267 | 8 020 | 5 629 | 3 695 |
| **Total assets** | **70 169** | 69 746 | 32 528 | 24 509 | 18 959 |
| **Ending capital employed** (A) | | | | | |
| Short-term and long-term debt, less cash and cash equivalents | **11 112** | 13 377 | 7 226 | 3 248 | 1 849 |
| Shareholders' equity | **36 721** | 34 111 | 14 523 | 11 896 | 9 084 |
| | **47 833** | 47 488 | 21 749 | 15 144 | 10 933 |
| Less capitalized costs related to major projects in progress | **(12 889)** | (13 365) | (6 583) | (4 148) | (2 649) |
| | **34 944** | 34 123 | 15 166 | 10 996 | 8 284 |
| **Total Suncor employees** (number at year-end) | **12 076** | 12 978 | 6 798 | 6 465 | 5 766 |

Footnotes, see page 95.

## FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

| ($ millions) | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **Dollars per common share** | | | | | |
| Net earnings attributable to common shareholders | **2.29** | 0.96 | 2.29 | 3.23 | 3.23 |
| Cash dividends | **0.40** | 0.30 | 0.20 | 0.19 | 0.15 |
| Cash flow from operations | **4.26** | 2.34 | 4.36 | 4.38 | 4.95 |
| **Ratios** | | | | | |
| Return on capital employed (%) [(B)] | **10.1** | 2.6 | 22.5 | 29.3 | 40 |
| Return on capital employed (%) [(C)] | **7.4** | 1.8 | 16.3 | 21.5 | 30.1 |
| Return on shareholders' equity (%) [(D)] | **10.2** | 5.1 | 16.2 | 28.4 | 39 |
| Debt to debt plus shareholders' equity (%) [(E)] | **25** | 29 | 35 | 24 | 21 |
| Net debt to cash flow from operations (times) [(F)] | **1.7** | 4.8 | 1.8 | 0.8 | 0.4 |
| Interest coverage – cash flow basis (times) [(G)] | **11.9** | 7.2 | 13.0 | 23.4 | 30.6 |
| Interest coverage – net earnings basis (times) [(H)] | **8.4** | 3.0 | 8.9 | 18.8 | 25.5 |

(A) Capital employed – the sum of shareholders' equity plus short-term debt and long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(B) Net earnings adjusted for after-tax financing expenses (income) for the twelve month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less average capitalized costs related to major projects in progress (as applicable), on a weighted-average basis. For a detailed annual reconciliation of this measure see the Non-GAAP Financial Measures Advisory section of Suncor's 2010 Management Discussion and Analysis.

(C) Average capital employed including capitalized costs related to major projects in progress.

(D) Net earnings as a percentage of average shareholders' equity.

(E) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(F) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

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

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

## SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

| | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **OIL SANDS** | | | | | |
| **Production** (kbpd) | | | | | |
| Total production (excluding Syncrude) | **283.0** | 290.6 | 228.0 | 235.6 | 260.0 |
| Syncrude | **35.2** | 38.5** | — | — | — |
| **Sales** (kpbd) | | | | | |
| Light sweet crude oil | **82.3** | 99.6 | 77.0 | 101.7 | 110.5 |
| Diesel | **20.4** | 29.1 | 19.8 | 25.0 | 28.2 |
| Light sour crude oil | **145.2** | 135.7 | 128.7 | 102.3 | 118.2 |
| Bitumen | **31.4** | 11.8 | 1.5 | 5.7 | 6.2 |
| | **279.3** | 276.2 | 227.0 | 234.7 | 263.1 |
| **Average sales price** (1) (dollars per barrel) (excluding Syncrude) | | | | | |
| Light sweet crude oil* | **79.03** | 67.26 | 98.66 | 78.03 | 71.98 |
| Other (diesel, light sour crude oil and bitumen)* | **68.63** | 64.18 | 95.14 | 70.86 | 65.17 |
| Total* | **71.69** | 65.29 | 96.33 | 74.07 | 68.03 |
| Total | **69.58** | 61.66 | 95.96 | 74.01 | 68.03 |
| Syncrude average sales price (1) (dollars per barrel) | **80.93** | 77.36 | — | — | — |
| **Operating costs – Total operations (excluding Syncrude)** (dollars per barrel) | | | | | |
| Cash operating costs (2) | **38.85** | 33.95 | 38.50 | 27.80 | 21.70 |
| Total cash operating costs (3) | **39.55** | 34.40 | 38.90 | 28.75 | 22.10 |
| Total operating costs (4) | **50.80** | 42.40 | 45.85 | 34.15 | 26.15 |
| **Operating costs – Syncrude** (dollars per barrel)*** | | | | | |
| Cash operating costs (2) | **37.95** | 32.50 | — | — | — |
| Total cash operating costs (3) | **37.95** | 32.50 | — | — | — |
| Total operating costs (4) | **50.15** | 44.65 | — | — | — |
| **Operating costs – In situ bitumen production only** (dollars per barrel) | | | | | |
| Cash operating costs (5) | **20.40** | 20.25 | 25.30 | 20.75 | 17.30 |
| Total cash operating costs (6) | **22.45** | 21.60 | 25.95 | 20.75 | 19.00 |
| Total operating costs (7) | **27.65** | 27.95 | 32.30 | 26.95 | 24.55 |

Footnotes, definitions and abbreviations, see page 100.

## SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

| | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **NATURAL GAS** | | | | | |
| **Gross production** | | | | | |
| Natural gas (mmcf/d) | | | | | |
| Continuing operations | **399** | 262 | 135 | 138 | 138 |
| Discontinued operations | **123** | 135 | 67 | 58 | 53 |
| Natural gas liquids and crude oil (kbpd) | | | | | |
| Continuing operations | **5.5** | 3.3 | 1.1 | 1.2 | 1.4 |
| Discontinued operations | **3.3** | 4.8 | 2.0 | 1.9 | 1.6 |
| Total (mmcfe/d) | | | | | |
| Continuing operations | **432** | 282 | 141 | 146 | 147 |
| Discontinued operations | **143** | 164 | 79 | 69 | 62 |
| **Average sales price from continuing operations** (1) | | | | | |
| Natural gas (dollars per mcf) | **3.99** | 3.63 | 8.21 | 6.50 | 7.30 |
| Natural gas (dollars per mcf) * | **3.99** | 3.62 | 8.23 | 6.41 | 6.95 |
| Natural gas liquids and crude oil (dollars per barrel) | **77.37** | 59.41 | 68.05 | 51.44 | 45.15 |

Footnotes, definitions and abbreviations, see page 100.

## SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

| | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **INTERNATIONAL AND OFFSHORE**** | | | | | |
| **East Coast Canada** | | | | | |
| **Production** (kbpd) | | | | | |
| Terra Nova | **23.2** | 20.8 | — | — | — |
| Hibernia | **30.9** | 27.2 | — | — | — |
| White Rose | **14.5** | 10.0 | — | — | — |
| **Total production** | **68.6** | 58.0 | — | — | — |
| **Average sales price** (1) (dollars per barrel) | **80.20** | 76.86 | — | — | — |
| **International** | | | | | |
| **Production** (kboe/d) | | | | | |
| *North Sea* | | | | | |
| Buzzard | **55.5** | 47.8 | — | — | — |
| Production from discontinued operations | **23.5** | 28.7 | — | — | — |
| Total North Sea | **79.0** | 76.5 | | | |
| *Other International* | | | | | |
| Libya | **35.2** | 32.6 | — | — | — |
| Syria**** | **11.6** | — | | | |
| Production from discontinued operations | **6.7** | 11.7 | — | — | — |
| **Total Other International** | **53.5** | 44.3 | — | — | — |
| **Total production** | **132.5** | 120.8 | — | — | — |
| **Average sales price from continuing operations** (1) (dollars per boe) | | | | | |
| Buzzard | **77.91** | 69.53 | — | — | — |
| Other International | **78.07** | 77.53 | | | |
| **Total International and Offshore Production** (kboe/d) | **201.1** | 178.8 | — | — | — |

Footnotes, definitions and abbreviations, see page 100.

## SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

| | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **REFINING AND MARKETING** | | | | | |
| **Eastern North America** | | | | | |
| **Refined product sales** (thousands of $m^3$/d) | | | | | |
| Transportation fuels | | | | | |
| Gasoline | **22.2** | 14.6 | 7.9 | 8.8 | 8.4 |
| Distillate | **12.4** | 8.8 | 5.2 | 5.4 | 3.9 |
| **Total transportation fuel sales** | **34.6** | 23.4 | 13.1 | 14.2 | 12.3 |
| Petrochemicals | **2.5** | 0.8 | 0.8 | 0.9 | 0.9 |
| Asphalt | **2.7** | 1.5 | 0.6 | 0.3 | — |
| Other | **5.5** | 2.0 | 1.0 | 2.2 | 1.9 |
| **Total refined product sales** | **45.3** | 27.7 | 15.5 | 17.6 | 15.1 |
| **Crude oil supply and refining** | | | | | |
| Processed at refineries (thousands of $m^3$/d) | **30.5** | 29.6** | 11.0 | 10.9 | 8.6 |
| Utilization of refining capacity (%) | **89** | 87 | 99 | 98 | 78 |
| **Western North America** | | | | | |
| **Refined product sales** (thousands of $m^3$/d) | | | | | |
| Transportation fuels | | | | | |
| Gasoline | **18.9** | 13.0 | 8.0 | 8.0 | 7.5 |
| Distillate | **18.5** | 9.5 | 5.6 | 5.2 | 4.6 |
| **Total transportation fuel sales** | **37.4** | 22.5 | 13.6 | 13.2 | 12.1 |
| Asphalt | **1.3** | 1.3 | 1.2 | 1.4 | 1.2 |
| Other | **3.8** | 3.4 | 1.2 | 1.3 | 1.1 |
| **Total refined product sales** | **42.5** | 27.2 | 16.0 | 15.9 | 14.4 |
| **Crude oil supply and refining** | | | | | |
| Processed at refineries (thousands of $m^3$/d) | **34.6** | 33.6** | 13.7 | 14.2 | 13.1 |
| Utilization of refining capacity (%) | **95** | 97 | 96 | 99 | 92 |
| **Retail outlets** (number at year-end) | **1 723** | 1 813 | 427 | 419 | 417 |

Footnotes, definitions and abbreviations, see page 100.

***Definitions***

(1) Average sales price – This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.

(3) Total cash operating costs – Include cash operating costs as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.

(4) Total operating costs – Include total cash operating costs as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.

(5) Cash operating costs – In situ bitumen production - Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in situ production volumes only.

(6) Total cash operating costs – In situ bitumen production - Include cash operating costs – In situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in situ production volumes only.

(7) Total operating costs – In situ bitumen production - Include total cash operating costs – In situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in situ production volumes only.

(8) Average price realized - This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

***Explanatory Notes***

* Excludes the impact of realized hedging activities.

** For the three months ended September 30, 2009 and the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

*** Users are cautioned that the Syncrude costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing treatments for operations and capital costs among producers.

**** Commercial production for Syria commenced on April 19, 2010.

## *Abbreviations*

| | | |
|---|---|---|
| kbpd | — | thousands of barrels per day |
| mcf | — | thousands of cubic feet |
| mcfe | — | thousands of cubic feet equivalent |
| mmcf/d | — | millions of cubic feet per day |
| mmcfe/d | — | millions of cubic feet equivalent per day |
| boe | — | barrels of oil equivalent |
| kboe/d | — | thousands of barrels of oil equivalent per day |
| $m^3/d$ | — | cubic metres per day |

## *Metric conversion*

| | |
|---|---|
| Crude oil, refined products, etc. | $1m^3$ (cubic metre) = approx. 6.29 barrels |

## RESERVES SUMMARY (1)(2)(3)

This data summarizes Suncor's oil, liquids and natural gas reserves and the net present values of future net revenues for these reserves using forecast prices and costs and prepared in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities*. For more information regarding our reserves and resources disclosure, please see the Statement of Reserves Data and Other Oil and Gas Information in our Annual Information Form (AIF), dated March 3, 2011. Reserves volumes are presented in millions of barrels (MMbbls), billions of cubic feet (Bcf) or millions of barrels of oil equivalent (MMboe).

The recovery and reserves estimates of oil, natural gas liquids (NGL) and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Estimates of net present value for future net revenues do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

**Reserves Summary**
(forecast prices and costs)

| | Synthetic Crude Oil (SCO) | | Bitumen | | Light & Medium Oil | | Natural Gas | | NGL | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross MMbbls | Net MMbbls | Gross MMbbls | Net MMbbls | Gross MMbbls | Net MMbbls | Gross Bcf | Net Bcf | Gross MMbbls | Net MMbbls | Gross MMboe | Net MMboe |
| Proved | 2 906 | 2 500 | 397 | 337 | 350 | 241 | 1 376 | 1 124 | 17 | 11 | 3 900 | 3 276 |
| Probable | 1 003 | 821 | 1 887 | 1 523 | 313 | 198 | 660 | 468 | 13 | 8 | 3 325 | 2 628 |
| Proved Plus Probable | 3 909 | 3 321 | 2 284 | 1 860 | 663 | 439 | 2 036 | 1 592 | 29 | 19 | 7 225 | 5 904 |

**Net Present Value of Future Net Revenues for Proved Plus Probable Reserves**
(forecast prices and costs)

| ($ millions, discounted at % per year) | 0% | 5% | 10% | 15% | 20% |
|---|---|---|---|---|---|
| Mining | 91 520 | 47 876 | 29 165 | 19 876 | 14 696 |
| In Situ | 110 937 | 39 954 | 18 477 | 10 126 | 6 172 |
| East Coast Canada | 9 994 | 7 842 | 6 399 | 5 384 | 4 640 |
| Natural Gas | 6 294 | 3 869 | 2 761 | 2 133 | 1 730 |
| North Sea | 13 927 | 11 014 | 9 108 | 7 775 | 6 794 |
| Other International (4) | 11 942 | 7 813 | 5 590 | 4 264 | 3 406 |
| **Total** | **244 614** | **118 368** | **71 500** | **49 558** | **37 438** |

**Gross Reserves Reconciliation for Proved Plus Probable Reserves**
(forecast prices and costs)

| | SCO MMbbls | Bitumen MMbbls | Light & Medium Oil MMbbls | Natural Gas Bcf | NGL MMbbls | Total MMboe |
|---|---|---|---|---|---|---|
| December 31, 2009 (5) | 4 192 | 2 010 | 743 | 3 757 | 55 | 7 626 |
| Extensions and improved recoveries (6) | 6 | 8 | 22 | 116 | — | 55 |
| Technical revisions (7) | (184) | 276 | 2 | (427) | (11) | 13 |
| Discoveries (8) | — | — | 2 | 2 | — | 2 |
| Dispositions | — | — | (39) | (1 036) | (10) | (222) |
| Economic factors (9) | — | — | — | (136) | — | (23) |
| Production | (106) | (10) | (67) | (241) | (3) | (226) |
| **December 31, 2010** | **3 909** | **2 284** | **663** | **2 036** | **29** | **7 225** |

(1) Gross refers to Suncor's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of Suncor; Net refers to Suncor's working interest (operating and non-operating) share after deduction of royalty obligations, plus the company's royalty interests in production or reserves.

(2) Reserves volumes in the above tables are rounded to the nearest MMbbls, Bcf or MMboe, as the case may be, and may not add due to rounding.

(3) The reserves data are based upon evaluations or reviews by GLJ Petroleum Consultants Ltd., Sproule Associates Limited and Sproule International Limited all completed with an effective date of December 31, 2010.

(4) Other International reserves, which include Libya and Syria, include quantities of crude oil and natural gas reserves that will be produced under PSCs, which involve the company in upstream risks and rewards, but which do not transfer title of the product to the company. Please see the Definitions for Reserves Data Tables section in the AIF.

(5) For the year ended December 31, 2009, Suncor had presented disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities requirements. As a result, closing balances presented in our 2009 AIF disclosure have been restated to comply with NI 51-101, consistent with the presentation format for December 31, 2010 reserves disclosure.

(6) Extensions and improved recoveries are positive increases to the reserves resulting from step-out drilling, infill drilling and installation of improved recovery schemes.

(7) Technical revisions include changes in previous estimates, upward or downward, resulting from new technical data or revised interpretations.

(8) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(9) Economic factors are changes due to product pricing.

## SHARE TRADING INFORMATION (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

| | **For the Quarter Ended** | | | | For the Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2010** | **June 30 2010** | **Sept 30 2010** | **Dec 31 2010** | Mar 31 2009 | June 30 2009 | Sept 30 2009 | Dec 31 2009 |
| **Share ownership** | | | | | | | | |
| Average number outstanding, weighted monthly (thousands)[(a)] | **1 560 744** | **1 561 650** | **1 562 538** | **1 564 170** | 936 550 | 937 005 | 1 349 263 | 1 559 512 |
| **Share price** (dollars) | | | | | | | | |
| Toronto Stock Exchange | | | | | | | | |
| High | **39.45** | **35.82** | **34.94** | **38.56** | 34.22 | 40.13 | 39.84 | 40.79 |
| Low | **29.93** | **29.91** | **30.72** | **32.25** | 21.15 | 27.44 | 29.90 | 34.66 |
| Close | **33.03** | **31.33** | **33.50** | **38.28** | 28.14 | 35.37 | 37.40 | 37.21 |
| New York Stock Exchange – US$ | | | | | | | | |
| High | **38.22** | **35.71** | **34.17** | **38.49** | 27.92 | 36.93 | 37.31 | 39.62 |
| Low | **28.04** | **27.65** | **28.56** | **31.53** | 16.95 | 21.61 | 25.51 | 31.84 |
| Close | **32.54** | **29.44** | **32.55** | **38.29** | 22.21 | 30.34 | 34.56 | 35.31 |
| **Shares traded** (thousands) | | | | | | | | |
| Toronto Stock Exchange | **293 414** | **334 463** | **237 687** | **241 413** | 408 851 | 361 886 | 339 790 | 277 779 |
| New York Stock Exchange | **503 927** | **582 189** | **302 054** | **374 370** | 778 887 | 697 065 | 541 485 | 436 930 |
| **Per common share information** (dollars) | | | | | | | | |
| Net earnings attributable to common shareholders | **0.46** | **0.31** | **0.65** | **0.87** | (0.20) | (0.06) | 0.69 | 0.29 |
| Cash dividends | **0.10** | **0.10** | **0.10** | **0.10** | 0.05 | 0.05 | 0.10 | 0.10 |

(a) The company had approximately 3,600 holders of record of common shares as at January 31, 2011.

**Information for Security Holders Outside Canada**

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

# INVESTOR INFORMATION

**Stock Trading Symbols and Exchange Listing**
Common shares are listed on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol SU.

**Dividends**
Suncor's Board of Directors reviews its dividend policy quarterly. In 2010, Suncor paid an aggregate dividend of $0.40 per common share.

**Dividend Reinvestment and Common Share Purchase Plan**
Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-877-982-8760. Information regarding the purchase plan is also available in the dividend information section of our website at www.suncor.com/dividends.

**Stock Transfer Agent and Registrar**
In Canada, Suncor's agent is Computershare Trust Company of Canada. In the United States, Suncor's agent is Computershare Trust Company, Inc.

**Independent Auditor**
PricewaterhouseCoopers LLP

**Independent Reserve Evaluators**
GLJ Petroleum Consultants Ltd., Sproule Associates Limited and Sproule International Limited

**Annual Meeting**
Suncor's Annual General Meeting of shareholders will be held at 10:30 a.m. (Calgary time) on May 3, 2011, at the Telus Convention Centre, 120 Ninth Avenue S.E., Calgary, Alberta. Presentations from the meeting will be webcast live at www.suncor.com/webcasts.

**Corporate Office**
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**Analyst and Investor Inquiries**
Steve Douglas, Vice President, Investor Relations
Toll-free number: 1-800-558-9071 E-mail: invest@suncor.com

**For further information, to subscribe or cancel duplicate mailings**
In addition to Annual and Quarterly Reports, Suncor publishes a Report on Sustainability. All Suncor publications, as well as updates on company news as it happens, are available on our website at www.suncor.com. To receive Suncor news as it happens, subscribe to Email Alerts, which can be found on our website. To order copies of Suncor's print materials call 1-800-558-9071.

If you do not receive our Annual or Quarterly Reports, but would like to receive these reports, call Computershare Trust Company of Canada at 1-877-982-8760 or visit their website at www.computershare.com. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com.

# GOVERNANCE AND DIRECTOR INFORMATION

## Corporate Governance

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors. The Board's oversight role encompasses Suncor's strategic planning process, risk management, standards of business conduct and communication with investors and other stakeholders. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest.

A comprehensive description of Suncor's governance practices, including a summary of any differences from those prescribed by the NYSE, is available in the company's Management Proxy Circular on Suncor's website at www.suncor.com or by calling 1-800-558-9071.

**Mel E. Benson(1)(2)**
**(independent)**
**Calgary, Alberta**
**Director since 2000**

Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000, Mr. Benson retired from a major international oil company. Mr. Benson is an owner of Tenax Energy Inc., a director of Winalta Inc. and director of the Fort McKay Group of Companies, a community trust. He is active with several charitable organizations including Hull Family Services. He is also a member of the board of governors for the Northern Alberta Institute of Technology.

**Brian A. Canfield(2)(3)**
**(independent)**
**Point Roberts, Washington**
**Director since 1995**

Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Beginning his career with TELUS as a telephone installer in 1956, Mr. Canfield rose through the corporate ranks to occupy positions as COO, President and CEO. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia and a fellow of the Institute of Corporate Directors. He was also the first businessperson to receive an honorary Doctorate of Technology from the BC Institute of Technology.

**Dominic D'Alessandro(3)(4)**
**(independent)**
**Toronto, Ontario**
**Director since 2009**

Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. and Canadian Imperial Bank of Commerce. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership.
Mr. D'Alessandro is an FCA, and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.

**John T. Ferguson[5]**
**(independent)**
**Edmonton, Alberta**
**Director since 1995**

John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research, Honorary Lieutenant Colonel – South Alberta Light Horse and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.

**W. Douglas Ford[1][4]**
**(independent)**
**Bonita Springs, Florida**
**Director since 2004**

W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals Inc. He is also a director of the Home Run Inn and a member of the board of trustees of the University of Notre Dame.

**Richard L. George**
**(non-independent, management)**
**Calgary, Alberta**
**Director since 1991**

Richard George is the president and chief executive officer of Suncor Energy Inc. He currently serves as the Canadian Chair of the North American Competitiveness Council and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

**Paul Haseldonckx[2][3]**
**(independent)**
**Essen, Germany**
**Director since 2009 (Petro-Canada 2002 to July 31, 2009)**

Paul Haseldonckx was a director of Petro Canada and a member of the management board of Veba Oel AG, Germany's largest downstream company, including Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.

**John R. Huff[1][2]**
**(independent)**
**Houston, Texas**
**Director since 1998**

John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of KBR Inc.

**Jacques Lamarre[1][2]**
**(independent)**
**Montreal, Quebec**
**Director since 2009**

Jacques Lamarre was the president and chief executive officer of SNC Lavalin from 1996-2009. Mr. Lamarre is an officer of the Order of Canada, and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the Board of Directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of The Royal Bank of Canada and of P3 Canada and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre is also a strategic advisor to Heenan Blaikie LLP, a law firm. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Laval University in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo, the University of Moncton and Laval University.

**Brian F. MacNeill[3][4]**
**(independent)**
**Calgary, Alberta**
**Director since 2009 (Petro-Canada 1995 to July 31, 2009)**

Brian MacNeill is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. Previously, Mr. MacNeill was a director and chairman of the board of Petro Canada. He is a director of TELUS Corporation, West Fraser Timber Co. Ltd., Capital Power Corp. and Oilsands Quest Inc. Mr. MacNeill is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors. Mr. MacNeill is also a member of the Order of Canada.

**Maureen McCaw[1][2]**
**(independent)**
**Edmonton, Alberta**
**Director since 2009 (Petro-Canada 2004 to July 31, 2009)**

Maureen McCaw was a director of Petro-Canada and is senior vice president (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a director of the Edmonton International Airport, Women Building Futures and Royal Alexandria Hospital, she is also managing partner at Prism Ventures. She is a past chair of the Edmonton Chamber of Commerce and serves on a number of Alberta boards and advisory committees.

**Michael W. O'Brien(3)(4)**
**(independent)**
**Canmore, Alberta**
**Director since 2002**

Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is lead director of Shaw Communications Inc. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.

**James W. Simpson(1)(4)**
**(independent)**
**Calgary, Alberta**
**Director since 2009 (Petro-Canada 2004 to July 31, 2009)**

James Simpson was a director of Petro-Canada and is past president of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee and Risk Review Committee, as well as being the chairman for the Audit Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.

**Eira M. Thomas(3)(4)**
**(independent)**
**West Vancouver, British Columbia**
**Director since 2006**

Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009 after serving as chief executive officer since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc., Fortress Minerals Corp., Ashton Mining of Canada Inc. and Lucara Diamond Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Human Resources and Compensation Committee
(2) Environmental, Health, Safety and Sustainable Development Committee
(3) Audit Committee
(4) Governance Committee
(5) As chairman, by standing invitation, Mr. Ferguson is considered an ex-officio member of all committees.

## CORPORATE OFFICERS

**Richard L. George**
President and Chief Executive Officer

**Steven W. Williams**
Chief Operating Officer

**Bart Demosky**
Chief Financial Officer

**Eric Axford**
Senior Vice President, Operations Support

**Kirk Bailey**
Executive Vice President, Oil Sands Ventures

**Boris Jackman**
Executive Vice President, Refining & Marketing

**François Langlois**
Senior Vice President, Exploration and Production

**Sue Lee**
Senior Vice President, Human Resources and Communications

**Mark Little**
Executive Vice President, Oil Sands

**Mike MacSween**
Senior Vice President, In Situ

**Kevin D. Nabholz**
Executive Vice President, Major Projects

**Janice Odegaard**
Senior Vice President, General Counsel and Corporate Secretary

**Anil Shah**
Vice President and Treasurer

**Andrew Stephens**
Senior Vice President, Business Services

**Jay Thornton**
Executive Vice President, Energy Supply, Trading and Development

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