SUNCOR ENERGY INC. **2011** 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 TSX and NYSE.

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The following is a list of abbreviations that may be used in this Annual Report:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d or kbpd	thousands of barrels per day
mmbbls	millions of barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
m^3	cubic metres
m^3/d	cubic metres per day
MW	megawatts

Places and Currencies

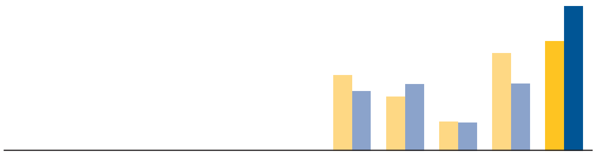
U.S.	*United States*
U.K.	*United Kingdom*
B.C.	*British Columbia*
$ or Cdn$	*Canadian dollars*
US$	*United States dollars*
£	*Pounds sterling*
€	*Euros*

Financial and Business Environment

IFRS	*International Financial Reporting Standards*
GAAP	*Generally Accepted Accounting Principles*
TSX	*Toronto Stock Exchange*
NYSE	*New York Stock Exchange*
WTI	*West Texas Intermediate*
WCS	*Western Canadian Select*
SCO	*Synthetic crude oil*
NGL(s)	*Natural gas liquid(s)*

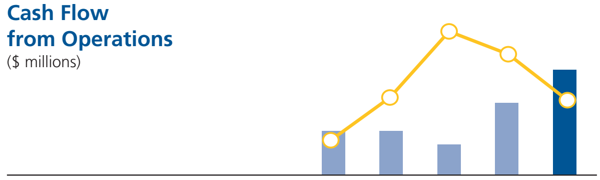
FINANCIAL HIGHLIGHTS [1]

Earnings
($ millions)



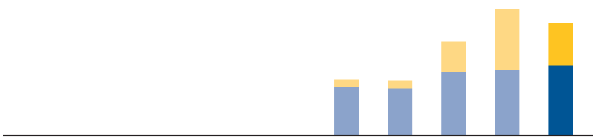
	2007	2008	2009	2010	**2011**
Net earnings	2 983	2 137	1 146	3 829	**4 304**
Operating earnings[(2)(3)]	2 341	2 617	1 115	2 634	**5 674**

Net Debt and Cash Flow from Operations
($ millions)



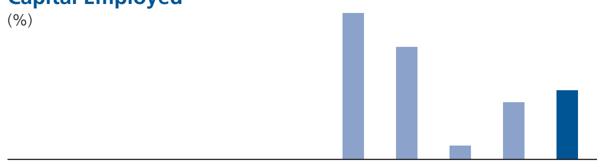
	2007	2008	2009	2010	**2011**
Net debt (at year end)	3 248	7 226	13 377	11 254	**6 976**
Cash flow from operations[(2)]	4 037	4 057	2 799	6 656	**9 746**

Production
(mboe/d)



	2007	2008	2009	2010	**2011**
Exploration and Production	35.8	36.7	149.3	296.9	**206.7**
Oil Sands	235.6	228.0	306.7	318.2	**339.3**
Total	271.4	264.7	456.0	615.1	**546.0**

Return on Capital Employed[(2)]
(%)



2007	2008	2009	2010	**2011**
29.3	22.5	2.6	11.4	**13.8**

Other Key Indicators

Year ended December 31	2007	2008	2009	2010	**2011**
Financial (dollars per common share)					
Net earnings – basic	3.23	2.29	0.96	2.45	**2.74**
Net earnings – diluted	3.17	2.26	0.95	2.43	**2.67**
Operating earnings[(2)(3)] – basic	2.54	2.81	0.93	1.69	**3.61**
Cash flow from operations[(2)] – basic	4.38	4.36	2.34	4.25	**6.20**
Dividend	0.19	0.20	0.30	0.40	**0.43**
Financial ($ millions)					
Operating revenues (net of royalties)	14 329	17 098	17 459	32 003	**39 337**
Capital and exploration expenditures	5 629	8 020	4 267	6 010	**6 850**
Total assets	24 509	32 528	69 746	68 607	**74 777**
Market Price of Common Shares (Closing as at December 31)					
TSX (Cdn$)	53.96	23.72	37.21	38.28	**29.38**
NYSE (US$)	54.37	19.50	35.31	38.29	**28.83**
Key Metrics					
Total debt to total debt plus shareholders' equity (%)	24	35	29	26	**22**
Net debt to cash flow from operations (times)[(2)]	0.8	1.8	4.8	1.7	**0.7**

(1) Unless otherwise noted, data for 2010 and 2011 is presented in accordance with IFRS and data for 2007 to 2009 is presented in accordance with Canadian GAAP in effect prior to January 1, 2011. The impacts of the transition to IFRS on the company's previously reported financial statements for the year ended December 31, 2010 are presented in the notes to the 2011 audited Consolidated Financial Statements. See the Advisories – Basis of Presentation section in the 2011 Management's Discussion and Analysis (the MD&A).

(2) Operating earnings, cash flow from operations and return on capital employed (which excludes major projects in progress) are non-GAAP financial measures, as are per common share and other key metrics which make use of these non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of the MD&A.

(3) The company has restated 2010 operating earnings for the transition to IFRS and 2007 to 2010 operating earnings for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of the MD&A.

ADVISORIES

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, including expectations and assumptions concerning: the accuracy of reserves and resources 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", "continue" and similar expressions. Forward-looking statements and other information in this Annual Report include those statements identified in the Advisory – Forward-Looking Information section of the MD&A contained in this Annual Report. Forward-looking statements in our "Message to Shareholders from the Chief Executive Officer", "Message to Shareholders from the President and Chief Operating Officer", "Our Scorecard" and "Suncor's Business Model" sections contained in this Annual Report include: Suncor's decade-long growth plan, including the expectations that (i) it will boost Suncor's total production to more than one million barrels of oil equivalent per day by 2020, including average oil sands production growth of approximately 10% per year through a prudent mix of in situ and mining projects, and including average company-wide production growth of approximately 8% per year, (ii) more than 80% of crude oil production will come from the oil sands, (iii) Suncor will have the largest oil sands upgrading complex in Canada, (iv) Suncor has the resources, expertise and business model to successfully advance the growth plan and deliver value to the company's shareholders, (v) Suncor's staged capital growth will minimize investment risk and maximize returns to our shareholders, and that there will be a period of lower risk growth through 2020, (vi) Suncor will direct most of its growth capital towards oil sands projects; and (vii) Suncor's conventional production will grow, driven largely by the planned development of Golden Eagle, the Hibernia Southern Extension Unit and Hebron, and should continue to account for approximately 20% of Suncor's estimated crude oil production through 2020; Suncor's expectation that it has more than 30 years of reserves that can be developed responsibly; Suncor's belief that it can internally finance its planned sustaining and growth capital for the coming year; the expectations that the company will fund base operations and capital growth primarily through internally generated revenues, continue to control costs and conservatively manage our balance sheet, and, subject to approval by Suncor's Board of Directors, return more cash to shareholders through increased dividends or more share buybacks; the company's expectations about the prospects for the ramp up of production from the Firebag Stage 3 expansion, and the ramp up of production from the Firebag Stage 4 expansion, which is expected to begin in 2013; Suncor's expectation that, by carefully phasing in its growth projects, it can smooth out some of the peaks and valleys for labour, material and services demands; Suncor's environmental performance goals targeted for 2015, including a 12% reduction in freshwater consumption, an increase in the reclamation of disturbed land area by 100%, a 10% improvement in energy efficiency and a 10% decrease in air emissions (all goals compared to 2007 levels); Suncor's anticipated investment constructing infrastructure to implement Tailings Reduction Operations (TRO_{TM}), and the company's belief that its TRO_{TM} tailings management technology will help it reduce the number of tailings ponds at our current base mine site from eight to one, allowing the company to reclaim entire mine sites in about a third of the time it now takes; the belief that the Energy Trading business will continue to evaluate additional pipeline commitments to support planned increases in production capacity; Suncor's 2012 targets and how it expects to achieve them and its ultimate target to maintain Oil Sands cash operating costs of $35 per barrel or less while absorbing the impacts of inflation, as discussed in the Our Scorecard section of the Annual Report; and all figures provided in our Corporate Guidance.

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, so 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 MD&A, including under the heading Risk Factors, and the company's 2011 Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov, which risk factors are incorporated by reference herein. 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.

All figures are presented in Cdn$ unless otherwise noted. Certain financial measures in this Annual Report – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings are defined in the Non-GAAP Financial Measures Advisory section of the MD&A and reconciled to GAAP net earnings in the Consolidated Financial Information, Segment Results and Analysis, and Non-GAAP Financial Measures Advisory sections of the MD&A. Cash flow from operations, ROCE and Oil Sands cash operating costs are defined and reconciled in the Non-GAAP Financial Measures Advisory section of the 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 because management uses the information to analyze operating performance, leverage and liquidity, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Certain crude oil and NGL volumes have been converted to mcfe and mmcfe of natural gas on the basis of one bbl to six thousand mcf. Also, certain natural gas volumes have been converted to boe, mboe and 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

MESSAGE TO SHAREHOLDERS FROM THE CHIEF EXECUTIVE OFFICER

If there's one motto I've tried to live by during my two decades at the helm of Suncor Energy, it's that actions always speak louder than words. In business, as in other aspects of anyone's life, making promises is easy – delivering results is much harder. That's why, for all of us at Suncor, 2011 was particularly noteworthy. It was a year when Suncor's integrated business model demonstrated its full value – maximizing margins on our barrels of oil to generate record operating earnings and cash flow. It was also a year when our ongoing focus on operational excellence led to impressive gains in overall reliability and record levels of oil sands production. Last, but far from least, 2011 saw Suncor continuing to harness technology in ways that will help us reduce our environmental footprint and our operating costs in the years ahead.

Last year was also the first full year of implementation of the company's decade-long growth plan, expected to boost our total production to more than one million barrels of oil equivalent per day by 2020. The strong financial and operating results achieved in 2011 bode well for Suncor's capacity to deliver profitable growth. We are targeting average Oil Sands production growth of approximately 10% per year and company-wide production growth of approximately 8% per year to 2020 – rates expected to outperform most major energy companies.

All the same, we take nothing for granted. Going forward, Suncor will continue to maintain a relentless focus on cost management and quality control, which will ultimately dictate the pace of the growth plan. We are confident that we have the resources, expertise and business model to advance our growth plan. But while the strategy is in place, we recognize that superior execution, rigorous management and constant oversight will be required as we pursue Suncor's central objective – to build strong and enduring shareholder value by responsibly producing the energy our society needs and demands.

2011: Building Shareholder Value

Compared to 2010, Suncor's annual operating earnings more than doubled in 2011 to a record $5.7 billion. Cash flow from operations was also the highest ever, at nearly $10 billion. While the results primarily reflected increased production from our Oil Sands business and a strong crude pricing environment, we also saw increased price realizations due to our capacity to upgrade bitumen and refine crude oil in-house. We are not only maximizing production, but we are also maximizing the margin on the barrels of oil we produce.

The built-in advantages of Suncor's integrated business model have become even more apparent since our 2009 merger with Petro-Canada. This brought the company expanded refining and marketing operations as well as lower cost oil and gas production internationally and offshore East Coast Canada. The net result: increased cash flow to strengthen the balance sheet, fund oil sands production growth and deliver value to shareholders.

In the space of just two years, Suncor has reduced its net debt from about $13.4 billion to just below $7 billion. In addition, Suncor completed a $500 million buyback of its common shares between September and December 2011, and increased its quarterly dividend by 10% starting in the second quarter of 2011. We believe the buyback represented an attractive investment opportunity and was in the best interests of our shareholders. We also see the buyback and the dividend increase as a show of confidence in the long-term strength of the company – and in our ability to deliver responsible, sustained and profitable growth.

We are currently well positioned, to the point that we believe we can internally finance our planned sustaining and growth capital spending for the coming year.

From an operational excellence perspective, we continued to see improvements in the reliability of our operated assets in 2011, further testament to the corporate-wide program led by Steve Williams, Suncor's president and chief operating officer. We successfully completed extensive maintenance to several assets across the company, including Suncor's largest ever turnaround at Upgrader 2, which was achieved safely and on schedule.

Even with all that planned maintenance, production from Oil Sands (excluding Syncrude) averaged a record 305,000 bbls/d in 2011 – capped by a single month record of 345,000 bbls/d in December. Significantly, over the fourth quarter in 2011, Suncor's In Situ production rate grew by approximately a third, to exit the year at about 111,000 bbls/d. We believe this to be just the beginning as Firebag Stage 3 continues to ramp up this year and next, and as Firebag Stage 4 is expected to begin its own ramp up in 2013.

It's estimated that some 80% of Canada's oil sands reserves are buried too deep to be reached by conventional mining. Of Suncor's proved plus probable Oil Sands reserves, nearly 60% are associated with the company's In Situ assets. As a result, in situ production – which injects steam into the deposit to heat the bitumen so it can flow to the surface – will be an increasingly important part of the industry's future. Suncor is already a leading player in this area, with two of the industry's most established in situ projects – Firebag, which has the most prolific production wells in the business, and MacKay River, which boasts an industry-leading low steam-to-oil ratio (a key indicator of energy efficiency and cost effectiveness).

On the international front, Suncor's operations in Libya and Syria faced challenging times in 2011. Operations were temporarily suspended in Libya last February in response to escalating political unrest in the region. We began a gradual return to the country during the fourth quarter following a change in the political regime and the lifting of sanctions.

In Syria, the "Arab Spring" unfolded in a different but no less concerning way. For much of 2011, we responded to the situation by working through a number of safety and security protocols, and maintaining a strong focus on corporate social responsibility. Ultimately, however, we suspended operations to comply with sanctions announced in December.

In both countries, we continue to monitor the situation very closely, and our top priority remains to ensure the safety of our employees. We have been consistent in our position that we will not operate in either country unless we can do so safely, responsibly and in compliance with international law.

We also continue to bring forward additional renewable energy projects and remain one of Canada's leading investors in this growing energy sector. In 2011, we commissioned two new wind farms and increased the company's total wind production capacity by nearly 75%. We also completed the expansion of our St. Clair ethanol plant in Ontario early in the year, doubling our production capacity to 400 million litres per year.

For the company overall, 2011 was a remarkable year. Despite changing world events, unstable market conditions, some operational challenges and an intensive maintenance schedule across our operations, Suncor posted record financial and operational results in 2011. This further demonstrates the strength of our integrated and flexible business model to deliver reliable shareholder value.

A Team Effort

When I first joined the company, Suncor had revenues of about $1.5 billion, we produced just a little over 60,000 bbls/d in our Oil Sands business and the company had a market capitalization of $1 billion. In 2011, Suncor's revenues were almost $40 billion, our Oil Sands business produced 305,000 bbls/d and market capitalization was nearing $50 billion.

Canada's oil sands represent a remarkable opportunity to produce the energy growing economies require. With more than 30 years of reserves (assuming production at approximately current levels) and one of the largest contingent resource bases in the oil sands industry, we can map out a long-term plan for responsibly developing this massive resource base.

For more than 20 years, I've had the honour of serving as Suncor's president and chief executive officer. In December, we announced that Steve Williams would take over immediately as president and succeed me as chief executive officer upon my retirement in May 2012.

I've worked closely with Steve for a number of years and admire his commitment to the safety, reliability and sustainability aspects of our business as well as his determination to foster industry collaboration. He has an intimate knowledge of Suncor's oil sands operations and a wealth of experience in both upstream and downstream operations.

I'm confident that the entire management team will serve Suncor and its shareholders extremely well in the years ahead. I'm very proud of what Suncor has accomplished over the past two decades and excited by what lies ahead for the company. I believe our strong balance sheet and growth strategy position Suncor very well for the long term.

I've often been asked about the secret to successful leadership and it's really quite simple – surround yourself with great people. At Suncor, I've done just that. Our company's success 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.

Throughout my years at Suncor, I've also benefited immensely from the knowledge and counsel of our Board of Directors, who oversee all strategic aspects of our business and are outstanding stewards of stakeholders' interests. They excel at challenging management to lead, innovate and grow our company profitably – and I want to recognize them for their steadfast guidance and support. In particular, I would like to recognize Brian MacNeill who is retiring this year after 17 years of service on the Board of Directors. Thank you Brian for your dedication to this company and in particular for serving as Chairman of Petro-Canada's Board of Directors. Your leadership was instrumental in bringing our two great companies together.

Suncor understands there is still substantial work ahead to meet the expectations of our shareholders – and all stakeholders – but our company welcomes the challenge. On behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support of this great company.

Rick George

Rick George
Chief Executive Officer

MESSAGE TO SHAREHOLDERS FROM THE PRESIDENT AND CHIEF OPERATING OFFICER

2011 was certainly a notable year, as reflected in Suncor's production, cash flow and earnings. It was also a significant year in terms of a transition in leadership. On December 1, our Chief Executive Officer, Rick George, announced his plan to retire, and the Board of Directors appointed me President and Chief Operating Officer, as well as a member of the Board.

I wish to extend my thanks to Rick for his leadership and vision over the past 20 years. I also speak on behalf of all our employees in extending our appreciation for his contributions to our company and communities.

I am honoured to have Rick and the Board's confidence and look forward to serving the company in this leadership role going forward. With a successful business model, continued improvements in reliability due to our focus on operational excellence, and a strong balance sheet, I believe we are well positioned to successfully execute our ten-year growth strategy and deliver value to our shareholders.

A Strong Foundation for Growth

The decade-long growth plan launched by Suncor in 2010 is, I personally believe, one of the most ambitious of its kind in the oil sands industry. But we are also uniquely positioned to deliver on that strategy. Most companies of our size planning for 8% to 10% annual production growth over several years would typically be carrying a highly leveraged balance sheet and plenty of inherent risk. Suncor, by contrast, is doing so with less than a one-times net debt to cash flow from operations ratio and at a time when its base operations are generating record levels of cash flow to fund growth. We have also taken great care to plan and stage capital growth in ways that we believe will minimize investment risk and maximize returns to our shareholders.

By sharing and sequencing the investment on some of our major projects with joint venture owners, and by staging our stand-alone projects in manageable pieces, we are prepared for what we expect to be a period of lower risk growth through 2020. It's also worth stressing that our ten-year plan strongly reinforces Suncor's strategic focus on the oil sands. Most of our growth capital spending during this period is expected to be directed towards oil sands projects. By 2020, we estimate more than 80% of the oil we produce will flow from the oil sands.

As Canada's oil sands pioneer, we intend to retain our leading position when it comes to developing one of the world's largest oil reserves.

As we do, Suncor will also enjoy unmatched flexibility in the way we produce and market this resource. The additional production through 2020 is expected to come from a prudent mix of in situ and mining projects – providing internal diversification, given different capital and operating cost structures – as well as potential technology advances associated with these two recovery methods.

Flexibility is also the hallmark of our integrated business model. As our growth plan unfolds, we expect to have the largest oil sands upgrading complex in Canada, with options to either upgrade product ourselves or send it directly to market. At the same time, we will continue to integrate oil sands products into Suncor's refining and marketing operations – one of the most profitable networks of its kind in North America (based on earnings per barrel of crude refining capacity). This strategy helps us capitalize on all aspects of the value chain while softening the impact of commodity price cycles and other market factors beyond our control. For example, in 2011, Suncor realized prices tied to global crude markets, which traded at significant premiums to WTI for most of the year, on over 90% of its upstream crude oil production.

Outside the oil sands, we are targeting production growth in our conventional Exploration and Production division, which includes our East Coast Canada, International and North America Onshore operations. In 2011, about 140,000 boe/d from this business was sold on the higher yielding Brent crude offshore-based benchmarks, another factor contributing to record cash flow.

As Suncor and the rest of the oil sands industry once again embrace growth, there is always the potential risk of triggering counterproductive inflation in labour, materials and services costs. We are working on several fronts to contain and manage costs in areas where we exercise control. By focusing more on cost and quality and less on schedules, and by carefully phasing in our growth projects, we are planning to smooth out some of the peaks and valleys of labour, materials and services demands.

Through years of experience and lessons learned, we've also developed a model for delivering growth projects safely, reliably and on budget. I like to think of it as a wheel with the following five spokes:

First, have the discipline to follow world-class processes. Second, complete engineering and procurement prior to mobilizing construction. Third, keep peak workforces on any site to a manageable size. Fourth, award smaller "bite-sized" contracts to contractors with proven track records. Fifth, apply lessons learned across all your projects.

The point here is that successful companies like Suncor do not have to reinvent the wheel each time a new project is launched. Instead, the key is to focus on strong execution and discipline, so that each of those five spokes is functioning to keep the wheel turning smoothly and efficiently.

Similar vigilance is required in running existing operations, which generate the revenues that make growth possible. That is why, as we implement our growth plan, we will continue to place a laser focus on achieving safe, reliable, environmentally responsible and cost-effective performance across our operations.

Coming off a record financial year such as 2011, some companies might be tempted to accelerate plans for growth. We believe our ten-year growth strategy is sufficiently ambitious – and that our focus should instead be on superior execution leading to continuously improved results for our shareholders and all stakeholders.

Going forward, we intend to fund base operations and capital growth primarily through internally generated revenues, continue to control costs and conservatively manage our balance sheet, and, subject to Board approval, return more cash to shareholders through increased dividends or more share buybacks.

Sustainable Development

As we implement our strategic growth plan, Suncor intends to remain true to its long-standing vision of a triple bottom line. That means we will continue to manage our business in ways that enhance social and economic benefits, while striving to minimize the environmental impacts associated with energy development.

Suncor was an early and proactive leader on the sustainability front. In the mid-1990s, we were one of the first companies to adopt a climate change action plan to better manage our greenhouse gas (GHG) emissions. By harnessing technology and improving energy efficiency, Suncor has reduced the GHG emissions intensity at its oil sands operations by over 50% compared to 1990 levels. Over the past six years, we've also reduced our total freshwater intake by more than 30%; our fresh water use is now the lowest since 1998, despite tripling production.

In 2011, the Carbon Disclosure Project (CDP) recognized Suncor's transparent disclosure of GHG emissions and continued focus on emissions management. Suncor topped the CDP's Canada 200 Carbon Disclosure Leadership Index and was one of the top three energy companies within the FSTE Global Index Series (Global 500).

We continue to lead the industry by pursuing a series of strategic, transparent and beyond-compliance environmental performance goals. By 2015, we are targeting a 12% reduction in freshwater consumption, an increase in the reclamation of disturbed land area by 100%, a 10% improvement in energy efficiency and a 10% decrease in air emissions, all compared to 2007 levels. All the targeted improvements are corporate-wide and absolute, except for energy efficiency, which is intensity-based. And each goal is challenging, particularly during a period of significant production growth.

Technology will remain critical in reaching these goals. At Suncor, we understand that investment in new technologies yields a double return – it reduces our ultimate operational costs while also mitigating our environmental footprint. One of the best recent examples: the new TRO$_{TM}$ tailings management technology introduced over the past two years at our Oil Sands Base mining operations.

Suncor is investing more than $1.2 billion constructing infrastructure to implement TRO$_{TM}$, which 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 base mine site from eight to one, allowing us to reclaim entire mine sites in about a third the time it now takes – resulting in more rapid restoration of natural habitats.

Within our own plant gates, and through collaboration with industry peers, we continue to explore the full range of possibilities to harness technology to improve our industry's performance – everything from making in situ oil recovery more energy efficient to the potential for waterless oil sands extraction.

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.

Steve Williams
President and Chief Operating Officer

OUR SCORECARD

Our scorecard should be read in conjunction with Suncor's 2011 MD&A, and the audited Consolidated Financial Statements and accompanying notes. Goals for 2011 are as expressed in Suncor's 2010 Annual Report.

2011: Our Goals and How We Delivered

Achieve annual Oil Sands production of 280,000 to 310,000 bbls/d at a cash operating cost average of $39 to $43 per barrel.

- Oil Sands production increased 7.5% compared to 2010 levels, averaging 304,700 bbls/d, as the company safely and successfully completed the largest upgrader planned maintenance event in its history. This event, which was completed safely and on schedule, was followed by the two highest Oil Sands production quarters on record. Actual cash operating costs per barrel of $40.20 were in line with this target and included the impacts of the ramp up of production from the Firebag Stage 3 expansion, as planned.

Establish a solid Exploration and Production division.

- In 2011, the former International and Offshore and Natural Gas businesses were merged into a single Exploration and Production business. The inaugural year for this business included responding to some headwinds, including the suspension of operations in Libya and Syria due to political unrest, and low natural gas prices in North America. Despite these challenges and other pressures on production volumes, exposure to high Brent crude oil prices (which traded at a significant premium to WTI for much of the year) enabled Exploration and Production to continue delivering strong cash flow, ending the year on a solid footing.

Lay a sound foundation for our long-term growth strategy.

- Suncor created a new business area – Oil Sands Ventures – to manage and develop assets in partnership with joint venture owners. Throughout 2011, Oil Sands Ventures focused on planning the successful restart of the Fort Hills mining and Voyageur upgrader projects, and building organizational expertise and capacity to effectively manage the new joint ventures.

Maintain a strong balance sheet.

- Cash flow from operations increased by nearly 50%, while the company's net debt fell approximately 40% in 2011 compared to 2010, improving the net debt to cash flow from operations ratio from 1.7:1 to 0.7:1.

Maintain a focus on operational excellence.

- Suncor continued to implement its company-wide operational excellence program. We successfully completed extensive maintenance on several assets across the company and saw overall improvements in the reliability of operated assets in 2011 as a result.

Continue efforts to reduce environmental impact.

- Suncor continued to make progress on environmental goals it announced in 2008. Implementation of $TRO_{TM,}$ leading to acceleration of land reclamation, and improvements in water consumption rates are two examples of Suncor's initiatives to reduce its environmental impact. In addition, an environmental excellence team at Suncor leverages information gathered during the Report on Sustainability reporting cycle to identify strategies to continue closing performance gaps.

2012: Our Targets and How We Will Get There

Continuous process improvement across all Suncor operations with a focus on safety, environment, reliability and people.

- As Suncor progresses with the implementation of our operational excellence management system (OEMS), we will target significant performance upgrades, including further improvements to our safety metrics and environmental performance, record oil sands production of between 325,000 and 355,000 bbls/d and improved employee engagement and retention statistics. By continuously optimizing our integrated business model, we will maximize the value of every barrel of oil we produce.

Rigorous cost control in our oil sands operations.

- Suncor places a high priority on the management of costs associated with Oil Sands production. Through initiatives to improve reliability and productivity and the application of new technologies, we target a reduction in our cash operating costs to an average between $37 and $40 per barrel in 2012. In future years, our ultimate target is to maintain Oil Sands cash operating costs of $35 per barrel or less while absorbing the impacts of inflation.

Steadily increasing production at Firebag

- With the ramp up of production from Firebag Stage 3 and the implementation of a successful infill drilling program at Stages 1 and 2, performance continues to improve at Firebag. Suncor will look to apply its learnings to date as we complete Stage 4 and prepare for first oil early in 2013.

  Suncor is investing in a portfolio of in situ technology projects with an aim to drive improvements and efficiencies in current production and develop future opportunities.

Superb execution of our capital projects.

- Suncor's 2012 budget includes capital expenditures of $7.5 billion, including over $3.6 billion dedicated to growth projects. We will seek to increase returns on investment through a disciplined focus on scope control, field execution, cost management and quality assurance. Cost and quality metrics, as opposed to schedules, will be the priority for Suncor when executing our growth projects. We will lay down capital efficiently and ensure an attractive return for shareholders.

Demonstrated capability to drive value through strategic partnerships.

- A significant portion of Suncor's Oil Sands growth program involves projects that will be developed with business partners. Suncor has established the Oil Sands Ventures organization with a mandate to optimize the value of these projects. As the company works towards investment decisions, a strict focus on effective project execution and efficient capital allocation will ensure returns on invested capital meet objectives.

Corporate Guidance

The following table provides actual results for the year ended December 31, 2011 and highlights forecasts from Suncor's 2012 Full Year Outlook. For further details regarding Suncor's 2012 Full Year Outlook, see www.suncor.com/guidance.

	Actual Year Ended December 31, 2011	**2012 Full Year Outlook February 1, 2012**
Suncor Total Production (boe/d)	546,000	**530,000 - 580,000**
Oil Sands (1)		
Production (bbls/d)	304,700	**325,000 - 355,000**
Sales		
SCO	280,400	**299,000 - 327,000**
Diesel	9%	**10%**
Sweet	30%	**38%**
Sour	61%	**52%**
Bitumen	24,000	**26,000 - 28,000**
Realization on crude sales basket	WTI @ Cushing less Cdn$5.35 per barrel	**WTI @ Cushing less Cdn$4.00 to Cdn$5.00 per barrel**
Cash operating costs (2)	$40.20 per barrel	**$37 to $40 per barrel**
Syncrude		
Production (bbls/d)	34,600	**36,000 - 38,000**
North America Onshore		
Production (mmcfe/d)	388	**310 - 340**
Natural gas	92%	**89%**
Crude oil and liquids	8%	**11%**
East Coast Canada		
Production (bbls/d)	65,600	**50,000 - 55,000**
International		
Production (boe/d)	76,400	**67,000 - 75,000**
Crude oil and liquids	82%	**99%**
Natural gas	18%	**1%**
Refining and Marketing		
Refined product sales (m^3/d)	83,100	**78,800 - 87,100**
Gasoline	48%	**47%**
Distillate	36%	**38%**
Other	16%	**15%**
Refinery utilization (3) (%)		
Eastern North America	94%	**85% - 94%**
Western North America	91%	**92% - 100%**
Crude oil processed (m^3/d)		
Eastern North America	32,000	**30,000 - 33,100**
Western North America	32,800	**34,200 - 37,000**

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

(2) Cash operating cost estimates are based on the following assumptions: (i) production volumes and sales mix as described in the table above, and (ii) an average natural gas price of $4.09 per gigajoule at AECO. Cash operating costs per barrel is a non-GAAP financial measure, which is defined and reconciled to GAAP in the Non-GAAP Financial Measures Advisory section of the MD&A. Effective 2012, the calculation of cash operating costs has been updated to better reflect the ongoing cash costs of production. As a result, the cost of diluent purchased for transportation of product to market and non-cash costs related to the accretion of liabilities for decommissioning and restoration provisions are no longer included. Certain cash costs relating to safety programs that were previously considered non-production costs are now included in cash operating costs. The figure presented for the year ended December 31, 2011 has not been restated in accordance with these definition changes.

(3) Refinery utilizations are based on the following crude processing capacities: Montreal – 137,000 bbls/d (2011 – 130,000 bbls/d); Sarnia – 85,000 bbls/d; Edmonton – 135,000 bbls/d; and Commerce City – 98,000 bbls/d (2011 – 93,000 bbls/d).

For Oil Sands operations, Suncor anticipates average production between 325,000 and 355,000 bbls/d. This increase from 2011 assumes higher bitumen availability from growing In Situ operations and improvements in the company's mining operations. Suncor anticipates our share of Syncrude production to be between 36,000 and 38,000 bbls/d, which assumes a year of improved reliability based on focused work undertaken by Syncrude.

For 2012, Suncor anticipates the sweet portion (includes sweet SCO and diesel) of the sweet/sour mix to be approximately 48% of total sales of SCO, which assumes improved reliability and availability for secondary upgrading facilities. The company anticipates realizations on our crude sales basket of WTI less $4.00/bbl to $5.00/bbl, reflecting primarily improved sweet/sour sales mix, partially offset by premiums for SCO compared to WTI that are anticipated to be lower than experienced in 2011.

Suncor forecasts Oil Sands cash operating costs per barrel in the range of $37 to $40 per barrel, which assumes increased costs associated with mining lower quality bitumen ore grade and operating Firebag Stage 3 while production volumes continue to ramp up, partially offset by the impacts of higher overall Oil Sands production.

For North America Onshore, Suncor anticipates average production in the range of 310 to 340 mmcfe/d, which assumes natural declines in reservoir performance and limited capital investment in new and existing fields, with natural gas production comprising 89% of total production. The company continues to evaluate opportunities to divest non-core assets, but the production range provided does not anticipate any disposals.

For East Coast Canada, Suncor anticipates average production between 50,000 and 55,000 bbls/d. Both Terra Nova and White Rose have major planned maintenance events scheduled for 2012 that require their respective floating production, storage and offloading (FPSO) vessels to disconnect from producing wells and travel to shore-based maintenance facilities.

For International, Suncor anticipates average production between 67,000 and 75,000 boe/d, which assumes improved reliability from Buzzard operations, a ramp up of production in Libya after the restart of operations and no production from Syria. Natural gas production is anticipated to comprise only 1% of International production, assuming there is no production from Syria in 2012.

Capital Expenditures (1)(2)

2012 Full Year Outlook February 1, 2012 ($ millions)	Total	Capital Sustaining	Growth
Oil Sands	5 085	2 885	2 200
Oil Sands Base	*1 780*	*1 555*	*225*
In Situ	*1 830*	*860*	*970*
Oil Sands Ventures	*1 475*	*470*	*1 005*
Exploration and Production	1 400	255	1 145
Refining and Marketing	600	590	10
Corporate	415	140	275
Total	**7 500**	**3 870**	**3 630**

(1) Capital expenditures exclude capitalized interest of $530 million to $630 million.

(2) Growth capital expenditures include economic capital investments that result in:

- An increase in production levels at existing Oils Sands operations and Refining and Marketing operations, or the investment in new facilities or operations that increases overall production;
- An addition of new reserves or a positive change in the company's reserves profile in Exploration and Production operations; or
- Margin improvement, by increasing revenues or reducing costs.

Sustaining capital expenditures include investments that:

- Ensure compliance or maintain goodwill relations with regulators and other stakeholders;
- Improve efficiency and reliability of operations or maintain productive capacity by replacing component assets at the end of their useful lives;
- Deliver existing proved developed reserves for Exploration and Production operations; or
- Maintain current production capacities at existing Oil Sands operations and Refining and Marketing facilities.

Included in the above table under the column sustaining capital is $450 million for TRO_{TM} and other expenditures related to reclamation for Oil Sands Base and $165 million for off-station turnarounds in Exploration and Production.

Capital expenditures attributed to Corporate in the table above include expenditures related to the Energy Trading and Renewable Energy operations, expenditures to improve effectiveness of corporate systems and processes, and $250 million of growth capital in a discretionary capital pool to be allocated to business units for new projects during the year at the discretion of management.

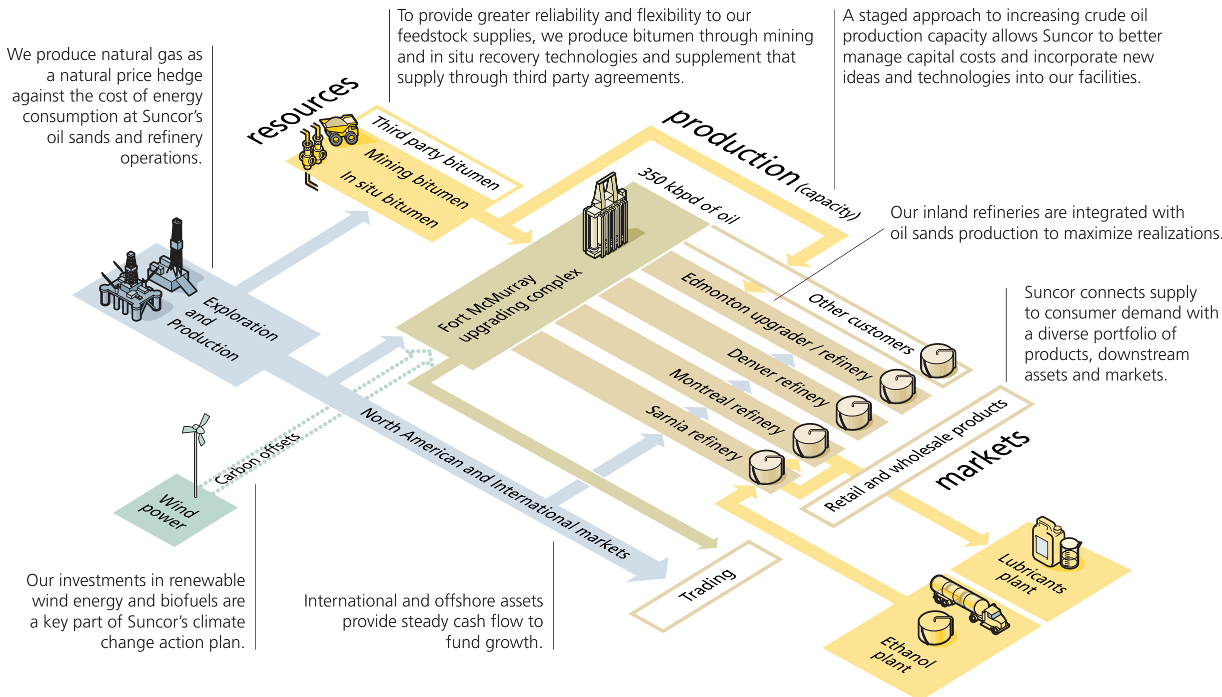
Advisories

The Our Scorecard and 2012 Corporate Guidance discussions above contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond Suncor's control, including those outlined below. See also the Advisories section of this report for the additional risks and assumptions underlying this forward-looking information.

Assumptions for the Oil Sands and Syncrude 2012 Full Year Outlook include those relating to reliability and operational efficiency initiatives that we expect will minimize unplanned maintenance in 2012. Assumptions for the North America Onshore, East Coast Canada, and International 2012 Full Year Outlook include those relating to reservoir performance, drilling results, facility reliability, and successful execution of planned maintenance events. Factors that could potentially impact Suncor's 2012 Full Year Outlook include, but are not limited to:

- Bitumen supply. A temporary decline in bitumen ore grade quality that is expected to impact mining operations until the start of the fourth quarter of 2012, unplanned maintenance of mine equipment and extraction plants, tailings storage and in situ reservoir performance.
- Performance of recently commissioned facilities. Production rates while new equipment is being brought into service are difficult to predict and can be negatively impacted by unplanned maintenance. Sweet production from Oil Sands may be dependent on successful commissioning of the Millennium Naphtha Unit.
- Unplanned maintenance. Production estimates could be negatively impacted if unplanned work is required at any of our mining, production, upgrading, refining, pipeline, or offshore assets.
- Planned maintenance events. Production estimates could be negatively impacted if planned maintenance events – such as those currently planned in 2012 for secondary upgrading units at both Upgrader 1 and Upgrader 2, and the extended off-station maintenance programs for the Terra Nova and White Rose FPSOs – are affected by unexpected events or not executed effectively.
- Commodity prices. Declines in commodity prices may alter our production outlook and/or reduce our capital expenditure plans.
- Foreign operations. Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's production in Libya, which has begun to ramp up and which the Full Year Outlook assumes will continue to produce at certain levels in 2012, may be constrained by further political unrest.

SUNCOR'S BUSINESS MODEL



Suncor's integrated, diversified business model aims to maximize the market price received and net margins realized for upstream production. Suncor has operations in most stages of the oil and gas industry – from resource extraction through to refining and retail. This diverse portfolio of assets helps fund growth projects, balance some of the volatility in our revenues, and reduce our financing risk through fluctuating economic cycles.

How is Suncor's business model integrated?

In 2011, the prices Suncor realized for sales of its upgraded and refined oil sands production were significantly higher than the prices Suncor realized for sales of non-upgraded bitumen. The key components of the company's integrated model are as follows:

Suncor upgrades most of its bitumen production into more valuable light products.

Suncor's upgrading capacity of 350,000 bbls/d of SCO enabled the company to capture the spread between light and heavy crude oil prices by converting bitumen into light synthetic crude oil. This premium for upgrading bitumen (approximated by the difference between the average prices realized for light crude oil and bitumen) has increased 150% since 2009, averaging $10.50/bbl in 2009, $15.65/bbl in 2010 and $25.95/bbl in 2011.[(1)]

Suncor optimizes price realizations for oil sands barrels by leveraging midstream infrastructure.

Suncor's Energy Trading business has entered into arrangements for pipeline and storage capacity that, combined with Suncor's upgrading flexibility, enabled Suncor to optimize realizations for oil sands production.

Suncor processes synthetic crude oil into more valuable refined petroleum products.

In recent years, Suncor has made significant investments in its inland refineries (Edmonton, Sarnia, and Commerce City) to process oil sands production. As a result, the company was able to capture the spread between WTI and global crude oil prices, as prices for refined products were tied to global markets based on Brent crude.

Suncor reaches consumers of refined fuels and specialty products through its broad marketing network.

Suncor's retail, wholesale and lubricants marketing channels boosted earnings beyond the refinery gate. Through its Petro-Canada branded outlets, Suncor continues in its position as a leading retailer in Canada.

(1) Alberta Energy Resources Conservation Board publication *ST3: Alberta Energy Resource Industries Monthly Statistics* for the period from January 1, 2009 to November 30, 2011.

How are Suncor's assets diversified?

In 2011, Suncor delivered record cash flow from operations, benefiting from a diverse asset base that has protection from volatile trends in market pricing. Despite prices for WTI that were significantly discounted compared to Brent crude throughout most of 2011, Suncor realized prices tied to global crude markets on over 90% of its upstream crude production.

Suncor's inland refineries help protect against price movements in WTI.

In 2011, approximately 75% of Suncor's upstream crude oil production came from the oil sands. While price realizations for this production were largely based off of WTI, Suncor's inland refinery capacity of 313,000 bbls/d captured additional margins, essentially providing global market prices for approximately 90% of this oil sands production.

Suncor is geographically diversified by having offshore and international oil and gas production, which is sold into premium-priced markets.

Most of Suncor's remaining upstream crude oil production from the Exploration and Production segment received prices directly based on Brent crude.

Suncor's production and asset diversification also helps protect against price movements and changing market conditions.

For much of 2011, synthetic crude oil also traded at a premium to WTI. Suncor's flexible upgrading configuration helps to optimize realizations by allowing the company to blend synthetic crude oil to specifications desired by its refining customers, or manage internal or external constraints, such as pipeline disruptions. The benefit to upstream realizations associated with higher synthetic crude oil prices was partially offset by higher feedstock costs at our refineries.

Although decreasing North American natural gas prices in 2011 reduced cash flow from natural gas assets in Western Canada, this impact was more than offset by lower operating costs for steam and power generation at our oil sands and refinery facilities.

How is Suncor's integrated, diversified strategy positioned for the future?

Suncor's long-term growth strategy has balance between mining, in situ and upgrading projects.

Suncor's long-term growth strategy includes major mining, in situ and upgrading projects. Although mining projects are generally larger and require more upfront capital, they have higher recovery factors, lower sustaining capital costs per barrel of production, and are well-suited to supplying large, steady volumes of bitumen to an upgrader.

The flexibility to deliver upgraded synthetic crude oil and non-upgraded bitumen optimizes realizations for our oil sands production through cycles of fluctuating light/heavy differentials. The supply of heavy crude oil from Alberta's conventional and non-upgraded oil sands sources is increasing, while demand is expected to be impacted by a potential expansion and modification of North American pipeline and refining networks. The Energy Trading business will continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Suncor and the oil sands industry are exploring multiple logistic opportunities to deliver oil sands crude to markets in the U.S. Gulf Coast, the Canadian West Coast, Ontario, Quebec and the Atlantic seaboard. This includes participation in a proposed reversal of Enbridge's Line 9, a crude pipeline currently running from Montreal to Sarnia. A reversal could enable delivery of oil sands crude to Montreal and provide improved opportunities to enhance the long-term flexibility and competitiveness of the Montreal refinery.

Suncor's long-term growth strategy also includes conventional projects.

Suncor's conventional production is expected to grow, driven largely by the planned development of Golden Eagle, the Hibernia Southern Extension Unit and Hebron, and should continue to account for approximately 20% of Suncor's estimated crude oil production through 2020.

SUNCOR'S OPERATIONAL EXCELLENCE MANAGEMENT SYSTEM

Operational excellence is transforming Suncor and providing it with the opportunity to compete on a global scale. Operational excellence means managing the company using consistent standards and practices, and always improving. Suncor strives to:

- Be a leader in safety and environmental sustainability;
- Contribute to the highest level of performance;
- Balance performance with a lowest cost mentality;
- Ensure reliability in our assets, systems and people;
- Make smart choices that are repeatable in other parts of the business; and
- Use common standards across the company.

Suncor is in the process of implementing a new management system across the organization called the Operational Excellence Management System, or OEMS. A management system is the set of standards, practices and procedures that govern a company and determine how the company conducts its business to achieve its goals.

There are three main purposes for OEMS:

- To ensure compliance with all legal requirements and commitments;
- To adequately manage and control risk; and
- To apply a continuous improvement mindset to operational performance and make sure it is sustained.

OEMS links all standards, systems and processes required to manage operational risk, mitigate environmental impacts and deliver safe, reliable operations. OEMS has the ultimate goal of guiding the delivery of operational excellence. Suncor's process safety program that was launched in 2009 to bring early focus to addressing process safety hazards and Suncor's enterprise risk management system are both in alignment with OEMS.

OEMS is a journey that will take several years to fully implement across Suncor and even longer to realize the full benefits. One of the first steps is to conduct baseline self-assessments. The purpose of an assessment is to examine the various systems, standards, processes, and procedures that each organizational unit uses, and evaluate them against the OEMS requirements. Once baseline self-assessments are completed, Suncor can develop plans to close gaps and align with OEMS.

People

Recruit and retain sufficient, capable, motivated people and significantly improve the people productivity of our business

Personal and process safety

Continue our Journey to Zero and significantly improve the integrity and performance of our assets

Environmental excellence and sustainability

Significantly improve the environmental performance of our business and go "beyond compliance" in key areas

Reliability

Significantly improve the reliability of our business

RESERVES AND RESOURCES SUMMARY

Summary of Oil and Gas Reserves[1]

as at December 31, 2011 (forecast prices and costs)	SCO Gross mmbbls	SCO Net mmbbls	Bitumen Gross mmbbls	Bitumen Net mmbbls	Light & Medium Oil Gross mmbbls	Light & Medium Oil Net mmbbls	Natural Gas Gross bcf	Natural Gas Net bcf	NGLs Gross mmbbls	NGLs Net mmbbls	Total Gross mmboe	Total Net mmboe
Proved	2 728	2 343	709	612	361	257	1 266	1 007	19	12	4 028	3 392
Probable	1 824	1 540	694	552	421	282	729	434	18	9	3 079	2 455
Proved Plus Probable	4 552	3 883	1 403	1 164	782	539	1 995	1 441	37	21	7 107	5 847

Reconciliation of Gross Proved Reserves[1][2]

(forecast prices and costs)	SCO mmbbls	Bitumen mmbbls	Light & Medium Oil mmbbls	Natural Gas bcf	NGLs mmbbls	Total mmboe
December 31, 2010	2 906	397	350	1 376	17	3 900
Extensions and improved recoveries	94	87	5	5	—	187
Technical revisions	(157)	234	42	156	6	150
Discoveries	—	—	25	1	—	25
Dispositions	—	—	(16)	(60)	(1)	(27)
Economic factors	—	—	—	(54)	—	(9)
Production	(115)	(9)	(45)	(158)	(3)	(198)
December 31, 2011	2 728	709	361	1 266	19	4 028

Suncor's gross proved reserves as at December 31, 2011 increased approximately 3% from December 31, 2010 and approximately 9% after adjusting for production and dispositions during 2011. Increases in gross proved reserves were due mainly to drilling and new well pad applications at Firebag and MacKay River, the reclassification of contingent resources to proved reserves for the Golden Eagle development, and various technical revisions.

Reconciliation of Gross Proved and Probable Reserves[1][2]

(forecast prices and costs)	SCO mmbbls	Bitumen mmbbls	Light & Medium Oil mmbbls	Natural Gas bcf	NGLs mmbbls	Total mmbbls
December 31, 2010	3 909	2 284	663	2 036	29	7 225
Extensions and improved recoveries	—	—	150	16	—	152
Technical revisions	758	(872)	1	278	12	(54)
Discoveries	—	—	38	3	—	38
Dispositions	—	—	(25)	(92)	(1)	(41)
Economic factors	—	—	—	(88)	—	(15)
Production	(115)	(9)	(45)	(158)	(3)	(198)
December 31, 2011	4 552	1 403	782	1 995	37	7 107

Suncor's gross proved plus probable reserves as at December 31, 2011 decreased approximately 2% from December 31, 2010. After adjusting for production and dispositions during 2011, and technical revisions for the reclassification of certain In Situ bitumen reserves that are now forecasted to be upgraded and as a result are now classified as SCO reserves, gross proved plus probables increased approximately 4%. Remaining increases in gross proved plus probable reserves were due mainly to the reclassification of contingent resources to proved plus probable reserves for the Golden Eagle and Hebron developments and various technical revisions.

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

(2) Extensions and improved recoveries are positive increases resulting from step-out drilling, infill drilling and installation of improved recovery schemes. Discoveries are additions in reservoirs where no reserves were previously recorded. Technical revisions include changes in previous estimates (upward or downward) resulting from technical data or revised interpretations. Economic factors are changes due to product and other pricing.

Net Present Value of Future Net Revenues Before Income Taxes

Proved plus probable reserves (forecast prices and costs, in $ millions)	0%	5%	10%	15%	20%
Oil Sands — Mining	93 888	49 647	31 757	22 770	17 598
Oil Sands — In Situ	100 844	36 525	17 247	9 818	6 322
East Coast Canada	18 168	11 426	7 904	5 854	4 563
International	27 576	19 764	15 221	12 320	10 329
North America Onshore	4 608	2 940	2 126	1 654	1 349
Total as at December 31, 2011	245 084	120 302	74 255	52 416	40 161
Total as at December 31, 2010	244 614	118 368	71 500	49 558	37 438

Best Estimate Gross Contingent Resources

(forecast prices and costs)	SCO mmbbls	Bitumen mmbbls	Light & Medium Oil mmbbls	Natural Gas bcf	NGLs mmbbls	Total mmboe
Oil Sands — Mining	4 582	2 156	—	—	—	6 738
Oil Sands — In Situ	6 432	6 020	—	—	—	12 452
East Coast Canada	—	—	247	2 203	—	614
International	—	—	526	281	1	574
North America Onshore(1)	—	—	116	8 150	13	1 487
December 31, 2011	11 014	8 176	889	10 634	14	21 865
December 31, 2010	12 462	5 291	956	10 370	17	20 454

(1) Contingent resources include offshore fields in the Arctic Islands and United States.

Contingent resources increased 7% to 21,865 mmboe at December 31, 2011. Increases to contingent resources included extensions of the MacKay River and Meadow Creek leases, acquisition of additional leases in the Audet area, technical revisions for In Situ assets, recognition of potential Hibernia secondary zones, and volumes attributed to discoveries in the Ballicatters, Butch and Wilson Creek areas. The net effects of Suncor's transactions with Total E&P Canada Ltd., which included the acquisition of an interest in the Joslyn oil sands mining project, the partial disposition of Suncor's interest in the Fort Hills oil sands mining project and a change in assumption that reclassified remaining Fort Hills contingent resources from SCO to bitumen, also increased contingent resources. These increases were partially offset by the transfer of resources to proved plus probable reserves for Golden Eagle and Hebron, and asset dispositions.

Advisories to Reserves and Resources Summary Tables

Reserves data summarizes Suncor's SCO, bitumen, light and medium oil, NGL and natural gas reserves and the net present values of future net revenues for these reserves using forecast prices and costs and was 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 Suncor's Annual Information Form dated March 1, 2012 (the 2011 AIF), which statement is incorporated by reference herein.

The reserves data is based on evaluations by GLJ Petroleum Consultants Ltd (GLJ), Sproule Associates Limited and Sproule International Limited, our independent qualified reserves evaluators, which were all completed with an effective date of December 31, 2011.

The SCO, bitumen, light and medium oil, NGLs 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 fair market value of the reserves. There is no assurance that the forecast prices and costs will be attained and variances could be material. International reserves, which include Libya and Syria, include quantities of light and medium oil, NGLs and natural gas reserves that will be produced under Production Sharing Contracts that involve the company in upstream risks and rewards, but do not transfer title of the production to the company.

Contingent resources are those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any of the contingent resources. Best estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production. GLJ conducted an independent assessment of best estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties to which reserves are attributed (Firebag and MacKay River). For In Situ properties without attributed reserves, GLJ audited Suncor's assessments of best estimate contingent resources volumes. Best estimate contingent resources for conventional properties were prepared by Suncor qualified reserves evaluators. All estimates were completed with an effective date of December 31, 2011. All contingent resources estimates were conducted in accordance with the Canadian Oil and Gas Evaluators Handbook. For more information regarding our contingent resources disclosure, including the specific contingencies that prevent the classification of the contingent resources as reserves, please see the Statement of Reserves Data and Other Oil and Gas Information in the 2011 AIF.

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 23, 2012

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2011 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated March 1, 2012 (the 2011 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. Information contained in or otherwise accessible through our website does not form a part of this MD&A, and is not incorporated into this MD&A by reference.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context requires otherwise.

MD&A – Table of Contents

1. ADVISORIES

Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which are within the framework of International Financial Reporting Standards (IFRS). Effective January 1, 2011, the company's audited Consolidated Financial Statements have been prepared in accordance with IFRS, and IFRS 1 *First-Time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. In previous years, the company prepared its financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative figures presented in this MD&A pertaining to Suncor's 2010 results have been restated to be in accordance with IFRS. The impacts of the transition to IFRS on the company's previously reported financial statements for the year ended December 31, 2010, and the opening balance sheet at January 1, 2010, are presented in the notes to the audited Consolidated Financial Statements.

Comparative figures for earnings and cash flows presented in this MD&A pertaining to Suncor's 2009 results were prepared in accordance with Previous GAAP and were not required by IFRS 1 or by the Canadian Securities Administrators to be restated in accordance with IFRS. Users of this information are cautioned that 2009 results may not be directly comparable with those for 2010 and 2011 and are advised to review the First-Time Adoption of IFRS note to the audited Consolidated Financial Statements.

All financial information is reported in Canadian dollars, unless otherwise noted. Certain amounts in prior years have been reclassified to conform to the current year's presentation. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted.

Non-GAAP Financial Measures

Certain financial measures 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 GAAP. Operating earnings are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to GAAP net earnings in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A. Cash flow from operations, ROCE and Oil Sands cash operating costs are defined and reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A. The company has restated operating earnings from 2010 for the transition to IFRS and operating earnings from 2007 to 2010 for the removal of certain prior period operating earnings adjustments.

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 the information to analyze operating performance, leverage and liquidity, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement	
bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
m^3/d	cubic metres per day
MW	megawatts

Places and Currencies	
U.S.	United States
U.K.	United Kingdom
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment	
DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil

Other 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 Advisory – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information.

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". Amounts disclosed in this MD&A for 2009 reflect the results of post-merger Suncor from August 1, 2009 together with the results of pre-merger Suncor only from January 1, 2009 through July 31, 2009, unless otherwise noted.

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

2. 2011 HIGHLIGHTS

- **Record operating earnings and cash flow from operations.**
  - Net earnings for 2011 were $4.304 billion, compared to $3.829 billion in 2010.
  - Operating earnings[(1)] for 2011 were a record $5.674 billion, compared to $2.634 billion in 2010.
  - Cash flow from operations[(1)] for 2011 was a record $9.746 billion, compared to $6.656 billion in 2010.

  These record financial results were due primarily to higher average upstream price realizations and downstream refining margins, and increased production from Oil Sands.

  - ROCE[(1)] (excluding major projects in progress) was 13.8% for the twelve months ended December 31, 2011, compared to 11.4% for the twelve months ended December 31, 2010. ROCE continues to improve and is at its highest level since the merger with Petro-Canada.

- **Balance sheet strength.**

  The company has a strong balance sheet with reduced net debt, due to significant cash flow from its integrated operations and proceeds from asset dispositions.

  - Net debt at December 31, 2011 was $7.0 billion, and has decreased from $11.3 billion at December 31, 2010.
  - Cash and cash equivalents at December 31, 2011 was $3.8 billion and has increased from $1.1 billion at December 31, 2010.

  Cash flow from operations exceeded 2011 capital and exploration expenditures (including capitalized interest) by $2.9 billion. Combined with proceeds from transactions with Total E&P Canada Ltd. (Total E&P) and other asset divestitures, Suncor cash balances increased significantly during the year. Suncor maintained its strong cash position throughout 2011, while increasing capital expenditures, repaying debt, completing a share repurchase program and increasing its dividend.

  During 2011:

  - The company spent $6.850 billion on capital and exploration expenditures, compared to $6.010 billion in 2010.
  - The company repaid $500 million of long-term debt and over $1.2 billion of short-term debt.
  - The company repurchased 17.1 million shares, returning $500 million to shareholders.
  - Starting in the second quarter of 2011, the company increased its quarterly dividend by 10% to $0.11 per common share.

- **Leadership transition – Suncor's long-standing CEO to retire.**

  In early December, Rick George, Suncor's chief executive officer (CEO), announced his plan to retire after more than 20 years at the helm. Steve Williams, Suncor's chief operating officer, was appointed as president and a member of the company's Board of Directors, and will assume the role of CEO upon Mr. George's retirement in May 2012.

- **Record production from Oil Sands reflected improved reliability through operational excellence.**

  Oil Sands production averaged a record 304,700 bbls/d in 2011. Production reflected improved reliability and increased bitumen feedstock from mining and In Situ operations. Oil Sands production averaged 345,000 bbls/d in December, another record. Production results for 2011 included the impacts of the largest planned maintenance event in the company's history, which was completed safely and on schedule.

- **In Situ production exits 2011 at 111,000 bbls/d.**

  Concurrent with the ramp up of production from the first well pad at the Firebag Stage 3 expansion and infill wells brought on-stream at existing well pads throughout the second half of 2011, In Situ bitumen production surpassed 100,000 bbls/d in late October, and exited 2011 at approximately 111,000 bbls/d.

  The ramp up of bitumen production from the Firebag Stage 3 expansion is expected to continue in 2012.

- **Progress on major growth projects.**

  Construction activity for the Firebag Stage 3 expansion is complete, while construction activity for the Firebag Stage 4 expansion is well underway. The company expects to begin production from the Stage 4 expansion late in the first quarter of 2013.

  The company started mining ore from the North Steepbank Extension (NSE) in late December. The hydrogen plant for the Millennium Naphtha Unit (MNU) produced hydrogen in December, before being taken off-line for minor modifications prior to further commissioning. The start-up of the naphtha hydrotreater for the MNU is expected in 2012.

- **Transactions with Total E&P and the creation of Oil Sands Ventures.**

  After receiving the necessary regulatory approvals, in the first quarter of 2011, Suncor and Total E&P completed the transactions they had previously announced in December 2010. In exchange for net proceeds of $1.820 billion and a 36.75% interest in the Joslyn oil sands mining project, Suncor sold to Total E&P a 49% interest in the Voyageur upgrader and a 19.2% interest in the Fort Hills oil sands mining project.

  In order to manage and develop these new jointly owned assets, Suncor created a new business area – Oil Sands Ventures. Throughout 2011, Oil Sands Ventures focused on ensuring the successful restart of the Fort Hills mining and Voyageur upgrader projects, and building organizational expertise and capacity to effectively manage these projects as well as Suncor's interests in Syncrude and the Joslyn mining project.

- **Suncor's integrated business model reaps the rewards of a strong refining environment.**

  The Refining and Marketing segment contributed over $2.5 billion to cash flow from operations in 2011. Throughout much of the year, North American refining margins were very strong, particularly for inland refineries – such as Suncor's Edmonton, Sarnia and Commerce City refineries – due to a wider discount for WTI crude, compared to Brent crude. Despite major planned maintenance events in 2011 at each of these inland refineries, overall refining utilization averaged 92% for 2011, reflecting the company's focus on reliable operations.

- **Unrest in Libya and Syria.**

  In Libya, for much of the year, production was shut-in and all operations and exploration activities were suspended due to political unrest that led to international sanctions and Suncor declaring force majeure under its contractual obligations. The transition to a new government in Libya later in 2011 resulted in the lifting of sanctions impacting Suncor's operations in Libya. Production from all major fields was successfully restarted by the joint venture operator in late 2011 and early 2012. Suncor is optimistic about a gradual return to full operations in the country.

  In Syria, amid continuing unrest, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in the country. The company has ceased recording all production and revenue from its Syrian assets. The company continues to comply with all relevant sanctions.

- **Non-core asset divestiture activity winds down.**

  During the year, the company completed dispositions of non-core assets in the U.K. portion of the North Sea and Western Canada for total net proceeds of $304 million. Due to market conditions confronting the company's North America Onshore operations, opportunities to divest additional natural gas properties that met the company's financial objectives were limited.

- **Suncor continues investment in renewable energy assets.**

  Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year and confirmed the plant as Canada's largest biofuels production facility. Suncor also commenced operations at two new wind power projects – the 88-MW Wintering Hills project in southern Alberta and the 20-MW Kent Breeze project in southwest Ontario.

- **Systems integration project completed.**

  The company completed the integration of assets acquired in the merger with Petro-Canada onto a common information systems platform.

- **Energy Trading optimizes price realizations for Oil Sands barrels.**

  Suncor's Energy Trading business contributed significantly to cash flow from operations in 2011. This business supports Oil Sands production by optimizing price realizations and managing inventory levels. In recent years, the Energy Trading business has entered into arrangements for midstream infrastructure, such as pipeline and storage capacity, which enables Suncor to optimize the delivery of existing and future growth production.

(1) Operating earnings, cash flow from operations and ROCE are non-GAAP financial measures. The company has restated operating earnings from 2010 for the transition to IFRS and for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

3. SUNCOR OVERVIEW

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

OIL SANDS

Suncor's Oil Sands segment, with assets located in northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The Oil Sands segment includes:

- **Oil Sands** operations refers to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands region. Oil Sands activities consist of:
  - **Oil Sands Base** operations include the Millennium and Steepbank (including the NSE) mining and extraction operations, two integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets – including utilities, energy and reclamation facilities, such as Tailings Reduction Operations (TRO_{TM}) assets.
  - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River, and supporting infrastructure, such as central processing facilities and cogeneration units. The majority of In Situ production is upgraded by Oil Sands Base; however, the company's marketing plan includes sales of bitumen when marketing conditions are favourable or as operating conditions at Oil Sands Base require.
- **Oil Sands Ventures** includes the company's interests in significant growth projects, including two where Suncor is the operator – the Fort Hills mining project (40.8%) and the Voyageur upgrader project (51%) – and one where Total E&P is the operator – the Joslyn mining project (36.75%). Oil Sands Ventures also includes the company's 12% interest in the Syncrude oil sands mining and upgrading joint venture.

EXPLORATION AND PRODUCTION

In January 2011, Suncor combined its International and Offshore and Natural Gas segments into the Exploration and Production segment, which consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

- **East Coast Canada** operations include Suncor's 37.675% working interest in Terra Nova, for which Suncor is the operator. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.
- **International** operations include Suncor's 29.89% working interest in Buzzard and a 26.69% interest in the Golden Eagle Area Development (Golden Eagle) – both of which are operated by another company – in the U.K. portion of the North Sea. Suncor also holds interests in several North Sea licences offshore the U.K. and Norway. Suncor owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor also owns, pursuant to Exploration and Production Sharing Agreements (EPSAs, a form of PSC), working interests in the exploration and development of oilfields in the Sirte Basin in Libya.

  Due to recent unrest in both countries, the company has declared force majeure under its contractual obligations in Libya and Syria. Operations in Libya are in the process of restarting, while operations in Syria have been suspended indefinitely.
- **North America Onshore** operations include Suncor's interests in a number of assets in Western Canada, which primarily produce natural gas.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

- **Refining and Product Supply** operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Quebec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta, and Commerce City, Colorado. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.
- Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include six operating wind power projects and the St. Clair ethanol plant in Ontario.
- **Energy Trading** activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.
- **Corporate** includes stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.
- Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

4. CONSOLIDATED FINANCIAL INFORMATION

Financial Highlights [1]

Year ended December 31 ($ millions, except per share amounts)	2011	2010	2009
Net earnings	**4 304**	3 829	1 146
per common share – basic	**2.74**	2.45	0.96
per common share – diluted	**2.67**	2.43	0.95
Operating earnings [2]	**5 674**	2 634	1 115
per common share – basic	**3.61**	1.69	0.93
Cash flow from operations [2]	**9 746**	6 656	2 799
per common share – basic	**6.20**	4.25	2.34
Dividends paid on common shares	**664**	611	401
per common share	**0.43**	0.40	0.30
Operating revenues (net of royalties)	**39 337**	32 003	17 459
Balance sheet			
Total assets	**74 777**	68 607	69 746
Long-term debt (including current portion)	**10 016**	10 347	13 880
Net debt	**6 976**	11 254	13 377

Segment Highlights [1]

Year ended December 31 ($ millions)	2011	2010	2009
Net earnings (loss)			
Oil Sands	**2 603**	1 520	557
Exploration and Production	**306**	1 938	78
Refining and Marketing	**1 726**	819	407
Corporate, Energy Trading and Eliminations	**(331)**	(448)	104
Total	**4 304**	3 829	1 146
Operating earnings (loss) [2]			
Oil Sands	**2 737**	1 379	1 048
Exploration and Production	**1 358**	1 193	150
Refining and Marketing	**1 726**	796	455
Corporate, Energy Trading and Eliminations	**(147)**	(734)	(538)
Total	**5 674**	2 634	1 115
Cash flow from (used in) operations [2]			
Oil Sands	**4 572**	2 777	1 251
Exploration and Production	**2 846**	3 325	1 280
Refining and Marketing	**2 574**	1 538	921
Corporate, Energy Trading and Eliminations	**(246)**	(984)	(653)
Total	**9 746**	6 656	2 799

(1) 2009 data is prepared in accordance with Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

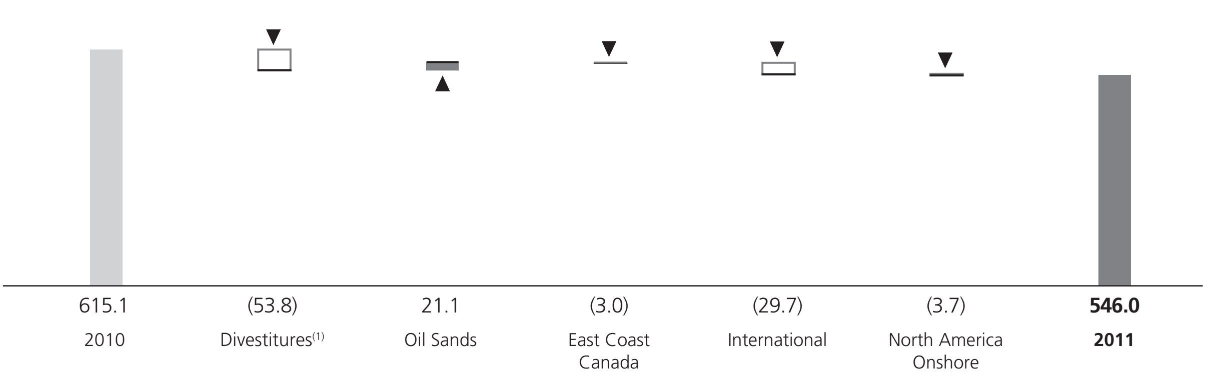
(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings in this section of the MD&A under the heading Consolidated Operating Earnings Reconciliation. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings from 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Operating Highlights

Year ended December 31	**2011**	2010	2009
Production volumes (mboe/d)			
Oil Sands	**339.3**	318.2	306.7
Exploration and Production	**206.7**	296.9	149.3
	546.0	615.1	456.0
Average price realizations			
Oil Sands ($/bbl)	**90.07**	70.85	62.53
Exploration and Production ($/boe)	**80.62**	59.47	57.44
	86.49	65.32	47.47
Refined product sales volumes (thousands of m^3/d)			
Eastern North America	**43.5**	45.3	27.7
Western North America	**39.6**	42.0	27.2
	83.1	87.3	54.9

Change in Production Volumes

(in mboe/d)



(1) The volume for divestitures compares annualized 2011 production with total production from 2010 for divested assets. Other figures presented for changes in production volumes include all other factors impacting production volumes.

The decrease in production volumes for 2011, compared with 2010, reflects primarily asset dispositions completed throughout 2010 and 2011. Suncor disposed of non-core natural gas assets in Western Canada and the U.S. Rockies, which contributed approximately 27.4 mboe/d more production than in 2011 (comprised of 23.8 mboe/d from assets disposed in 2010 and 3.6 mboe/d from assets disposed in 2011). Suncor also disposed of non-core North Sea assets, which contributed 19.7 mboe/d more production in 2010, and Trinidad and Tobago assets representing 6.7 mboe/d of 2010 production.

For Oil Sands, the production increase primarily reflected higher output from Oil Sands Base mining and extraction operations and the negative impacts of two upgrader fires at Oil Sands Base on production in the first half of 2010. Production from Syncrude in 2011 decreased slightly compared with 2010, due mainly to operational issues experienced late in 2011.

Excluding the impacts of asset divestitures, for Exploration and Production, decreases for International reflected primarily the shut-in of production in Libya for most of the year due to political unrest and outages at Buzzard for the repair of the cooling system and the completion and commissioning of the fourth platform. These decreases for International were partially offset by a year-over-year increase from Syria, which started producing in April 2010. Decreases for East Coast Canada primarily reflected the partial shut-in of production at Terra Nova due to the presence of hydrogen sulphide (H_2S) in some wells. Decreases for North America Onshore primarily reflected natural declines in reservoir performance.

Net Earnings

Suncor's net earnings for 2011 were $4.304 billion, compared to $3.829 billion in 2010. Net earnings were primarily affected by the same factors that influenced operating earnings, which are described in this section of the MD&A under the heading Operating Earnings. Other items affecting changes in net earnings in 2011, compared with 2010, included:

Operating Earnings Adjustments

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated long-term debt was $161 million in 2011, compared with a gain of $372 million in 2010. During 2011, the US$/Cdn$ exchange rate decreased from 1.01 to 0.98. During 2010, the US$/Cdn$ exchange rate increased from 0.96 to 1.01.
- In 2011, the company recorded net impairment charges of $503 million ($514 million initial impairment, net of $11 million of subsequent impairment reversals) against assets pertaining to its operations in Libya, which were shut-in as a result of unrest. The company also recorded $68 million of after-tax impairment charges against certain North America Onshore assets due to decreasing natural gas prices and after-tax write-offs of crude inventories of $58 million due primarily to third-party pipeline adjustments.

  In 2010, the company recorded after-tax write-offs of $143 million relating primarily to equipment used in an alternative mining and extraction process that was discontinued, after-tax impairment charges of $111 million against certain North America Onshore assets primarily due to decreasing natural gas prices, and after-tax impairment charges of $52 million against non-core U.K. assets that were eventually sold later in 2010 and in 2011.
- In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the statutory tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and to 62% in future years. As a result, the company revalued its deferred income tax balances, resulting in an increase to deferred income tax expense of $442 million.
- In 2011, the company disposed of assets resulting in after-tax losses of $107 million, consisting of $99 million on the partial disposition of interests in the Voyageur upgrader and Fort Hills projects, and $8 million for the sale of non-core Exploration and Production assets.

  In 2010, the company sold several non-core Exploration and Production assets (described in the Segment Results and Analysis – Exploration and Production section of this MD&A) and realized after-tax gains on disposal of $826 million.
- In 2011, Suncor recorded an after-tax provision of $31 million in the Exploration and Production segment related to a royalty dispute concerning the deductibility of certain costs for a period before the merger with Petro-Canada.

  In 2010, Suncor recorded after-tax expenses of $68 million for several other write-offs and provisions related to assets acquired in the merger.
- In 2010, the Oil Sands segment recorded after-tax gains of $233 million related to the change in fair value of certain commodity derivatives, net of realizations, which the company had entered into in previous years to manage the volatility of sales prices for its production.
- In 2010, Suncor recognized an after-tax gain of $166 million for the redetermination of its working interest in the Terra Nova oilfield, upon which the joint owners of Terra Nova reached agreement on a technical review of the interests they contributed.
- In 2010, Suncor recognized a favourable royalty recovery related to modifications made by the Alberta government to the Bitumen Valuation Methodology (BVM) calculation applicable to Suncor for the interim period from January 1, 2009 to December 31, 2010.

Consolidated Operating Earnings Reconciliation [1][2][3]

Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**4 304**	3 829	1 146
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)
Impairments and write-offs	**629**	306	42
Impact of income tax rate adjustments on deferred income taxes	**442**	—	4
Loss (gain) on significant disposals	**107**	(826)	39
Adjustments to provisions for assets acquired through the merger [4]	**31**	68	97
Change in fair value of commodity derivatives used for risk management, net of realizations [5]	**—**	(233)	499
Redetermination of working interest in Terra Nova	**—**	(166)	24
Modification of the bitumen valuation methodology	**—**	(51)	50
Merger and integration costs	**—**	79	151
Gain on effective settlement of pre-existing contract with Petro-Canada [6]	**—**	—	(438)
Costs related to deferral of growth projects [7]	**—**	—	299
Operating earnings	**5 674**	2 634	1 115

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Operating earnings is a non-GAAP financial measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Adjustment in 2011 related to a royalty dispute for a period prior to the merger. Adjustments in 2010 were for pipeline commitments that the company determined to be unfavourable as a result of certain non-core North America Onshore asset dispositions, the write-off of certain unproven properties in the Exploration and Production segment, changes in the provision for the cancellation of the Montreal refinery coker project, a dry hole in Libya, and other cost estimates associated with the transition to EPSAs in Libya. Adjustments in 2009 included the negative impact associated with inventory acquired at fair value.

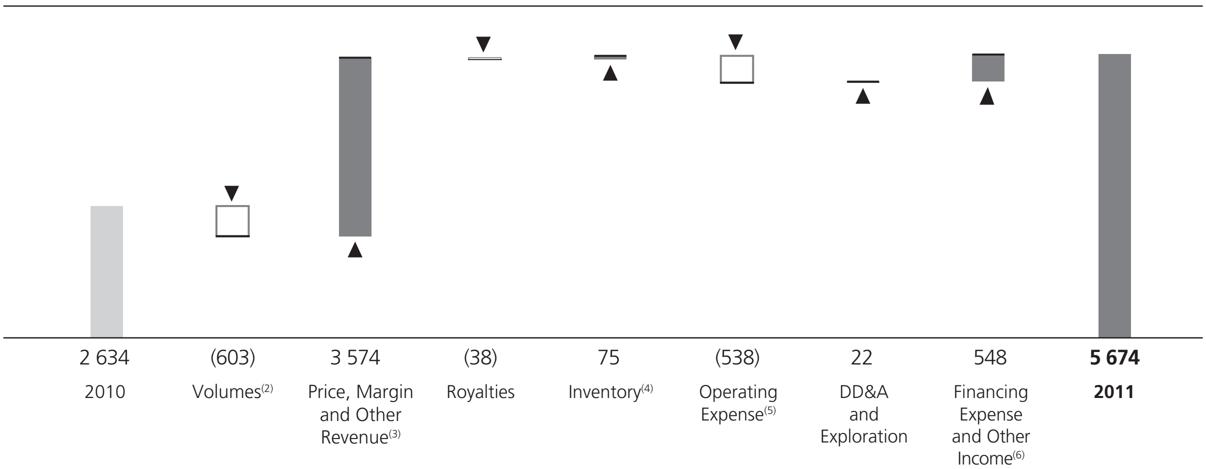
(5) Adjustments represent the change in fair value of significant crude oil risk management derivatives, net of realized gains and losses recognized on the final settlement of those derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings. The company held no significant crude oil risk management derivatives in 2011.

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

(7) The company incurred costs related to placing certain growth projects into "safe mode" due to unfavourable market conditions in prior years. The company stopped removing these costs from operating earnings effective January 1, 2010. After-tax safe mode costs for the years ended December 31, 2011 and 2010 were approximately $57 million and $94 million, respectively.

Bridge Analysis of Consolidated Operating Earnings [1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the Operating Earnings narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Calculated based on upstream production volumes and Refining and Marketing sales volumes.

(3) Includes upstream price realizations before royalties and transportation costs, refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude.

(4) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor for upstream assets based on production volumes, rather than based on sales volumes.

(5) This factor includes transportation expense, operating, selling and general expense and project start-up costs.

(6) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Operating Earnings

Suncor's consolidated operating earnings[1] for 2011 were $5.674 billion, compared to $2.634 billion in 2010. Positive factors impacting operating earnings in 2011, compared with 2010, included:

- Average price realizations for crude oil production from upstream assets were considerably higher in 2011, consistent with significant increases in benchmark prices for WTI and Brent crudes. The average price realization for the Oil Sands segment in 2011 was $90.07/bbl, compared to $70.85/bbl in 2010. The average price realization for the Exploration and Production segment was $80.62/boe in 2011, compared to $59.47/boe in 2010.
- Refining margins were higher in 2011, reflected by large increases in benchmarks for 3-2-1 crack spreads. Refining margins also benefited from the increasing crude price environment, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories purchased at relatively higher feedstock costs.
- Oil Sands production volumes (excluding Syncrude) increased to 304.7 mbbls/d from 283.0 mbbls/d, due primarily to higher bitumen output from Oil Sands Base and In Situ operations. Production volumes from the first half of 2010 were impacted by two upgrader fires.
- Financing expense was lower in 2011 than 2010, due mainly to an increase in capitalized interest (approximately $225 million more capitalized after tax). Suncor capitalized a higher percentage of its borrowing costs due mainly to amounts capitalized for the Voyageur upgrader, Fort Hills and Joslyn projects, subsequent to the completion of transactions with Total E&P.
- Other income was higher in 2011 than 2010, due mainly to higher operating earnings from Suncor's Energy Trading business. In addition, in 2010, the company realized losses on the final settlement of risk management activities pertaining to derivatives the company had entered into in previous years to manage the volatility of sales prices for its production.
- Share-based compensation expense was lower in 2011 than in 2010, due mainly to a decrease in the company's common stock price during the second half of the year. Operating expense for 2011 included after-tax share-based compensation expense of $24 million, whereas operating expense for 2010 included after-tax share-based compensation expense of $146 million.
- The Inventory variance factor was positive, primarily for Oil Sands, because inventories that were produced during the prior year at relatively lower production costs were sold and replaced by inventories produced during the current year at relatively higher production costs.
- DD&A was lower in 2011 than in 2010, due mainly to lower production volumes from Exploration and Production.

The positive factors noted above were partially offset by the following:

- Production volumes for the Exploration and Production segment decreased to 206.7 mboe/d from 296.9 mboe/d, primarily due to the divestiture of non-core assets throughout 2010 and 2011, the shut-in of production in Libya for the majority of 2011, unplanned outages at Buzzard, and the partial shut-in of wells at Terra Nova due to the presence of H_2S.
- Operating expenses, excluding the impacts of share-based compensation expense, were significantly higher in 2011 than in 2010, due mainly to the increase for the Oil Sands segment. Oil Sands Base mining costs were higher and reflected increased bitumen output and higher tonnes of ore moved while working through an area of lower bitumen ore grade quality. Oil Sands Base upgrading costs were higher due mainly to maintenance associated with secondary upgrading units. In Situ costs were higher due mainly to higher operating expenses and start-up costs associated with the Firebag Stage 3 expansion.
- Royalties were higher in 2011 than in 2010, mainly due to higher overall upstream price realizations.

Cash Flow from Operations

Consolidated cash flow from operations[1] for 2011 was $9.746 billion, compared to $6.656 billion in 2010. The increase was mainly due to the same factors that affected the increase in operating earnings, particularly higher upstream price realizations, refining margins and production from Oil Sands.

Results for 2010 compared with 2009

Net earnings for 2010 were $3.829 billion compared to $1.146 billion in 2009. Operating earnings[1] for 2010 were $2.634 billion compared to $1.115 billion in 2009. These increases were due primarily to the inclusion of a full year of operations from assets acquired in the merger with Petro-Canada on August 1, 2009 and higher upstream price realizations.

Upstream production for 2010 averaged 615.1 mboe/d, compared to 456.0 mboe/d in 2009. Downstream refined product sales averaged 87,300 m^3/d in 2010, compared to 54,900 m^3/d in 2009. Both volumes increased primarily due to new assets acquired in the merger. Higher production also meant higher royalties and DD&A in 2010, compared with 2009. The merger increased Suncor's asset base by approximately $35.8 billion (including goodwill) and long-term debt by $4.4 billion. Net earnings in 2010 included $826 million of after-tax gains on disposal of non-core assets, many of which were acquired through the merger.

Average price realizations were higher in 2010 than in 2009, as increases in important crude benchmarks like WTI and Brent more than offset the impacts of an increasing light/heavy crude differential and the Canadian dollar strengthening against the U.S. dollar.

Much of 2009 was affected by the general economic downturn. Suncor incurred after-tax expenses of $299 million to place certain growth projects in safe mode.

Cash flow from operations[1] was $6.656 billion in 2010, compared to $2.799 billion in 2009, and increased due mainly to the impacts of higher upstream production volumes from assets acquired in the merger and higher average price realizations.

Net debt decreased by $2.1 billion in 2010. Suncor sold non-core assets for total proceeds of approximately $3.5 billion during 2010 and used these funds mainly to reduce total debt.

(1) Operating earnings and cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of Suncor's operations.

(average for the year ended December 31, except as noted)		**2011**	2010	2009
WTI crude oil at Cushing	US$/bbl	**95.10**	79.55	61.80
Dated Brent crude oil at Sullom Voe	US$/bbl	**111.15**	79.50	61.50
Dated Brent/Maya FOB price differential	US$/bbl	**12.50**	9.30	5.00
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**95.75**	78.05	65.80
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**17.25**	14.20	9.70
Condensate at Edmonton	US$/bbl	**105.30**	81.90	60.45
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.65**	4.15	4.15
New York Harbor 3-2-1 crack[1]	US$/bbl	**27.00**	10.55	8.80
Chicago 3-2-1 crack[1]	US$/bbl	**24.65**	9.00	7.75
Portland 3-2-1 crack[1]	US$/bbl	**28.40**	13.55	11.40
Gulf Coast 3-2-1 crack[1]	US$/bbl	**24.80**	7.90	7.10
Exchange rate	US$/Cdn$	**1.01**	0.97	0.88
Exchange rate (end of period)	US$/Cdn$	**0.98**	1.01	0.96

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced primarily by changes in the price for WTI at Cushing. The average WTI price for 2011 increased to US$95.10/bbl from US$79.55/bbl in 2010. The WTI price continued to fluctuate significantly throughout 2011, and at times was as high as US$113/bbl and as low as US$80/bbl. Suncor's price realizations for SCO are also influenced by the supply and demand of sweet SCO from Western Canada. In 2011, sweet SCO averaged trading at a significant premium to WTI.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by changes to various crude benchmarks including, but not limited to, Canadian par crude at Edmonton and WCS at Hardisty, but which can also be affected by circumstances underlying spot sales required to manage inventory levels. Similar to WTI, prices for Canadian par crude at Edmonton increased significantly in 2011, compared to 2010. The average Edmonton par price was US$95.75/bbl in 2011 and US$78.05/bbl in 2010.

Bitumen production that Suncor does not upgrade is blended with diluent (or SCO) to facilitate delivery on pipeline systems to customers. Net bitumen price realizations are, therefore, influenced by prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at Edmonton). Diluent is sourced primarily from the company's own upgrading and refining facilities; however, purchases of diluent from third parties may be required when the company experiences operational outages. Bitumen price realizations can also be affected by bitumen quality and spot sales to manage inventory levels, and bitumen quality. Average price realizations for bitumen in 2011 were higher than those realized in 2010, due mainly to higher overall crude oil prices partially offset by wider light/heavy differentials and higher prices for diluent.

Suncor's price realizations for production from East Coast Canada and International assets are influenced primarily by the price for Brent crude. Brent crude averaged US$111.15/bbl in 2011, much higher than the average of US$79.50/bbl in 2010. The Brent crude price also fluctuated significantly throughout 2011, averaging over US$100/bbl since February, and at times was as high as US$126/bbl. Brent crude also began to trade at a substantial premium to WTI, averaging US$16.05/bbl for 2011, compared to a small discount of $0.05/bbl in 2010.

Suncor's price realizations for North America Onshore natural gas production are primarily referenced to Alberta spot at AECO. The AECO benchmark averaged $3.65/mcf in 2011, which was lower than the average AECO benchmark of $4.15/mcf in 2010.

Suncor's refining margins are influenced primarily by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates, and by light/heavy and light/sour crude differentials, which indicate when more complex refineries can earn greater margins by processing less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery because these benchmarks are calculated based off of WTI. In 2011, crack spreads were very high; in part because refined product prices reflected the higher priced Brent crude feedstock of coastal North American markets. This positively benefited Suncor's inland refineries (Sarnia, Edmonton and Commerce City) for much of 2011. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined product sales markets unique to that refinery's supply orbit.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on 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 revenue received from the sale of commodities. 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.

Conversely, many of Suncor's assets and liabilities are denominated in U.S. dollars, most notably much of the company's long-term debt, and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. An increase in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date decreases the Canadian dollars required to settle U.S. dollar denominated obligations and results in unrealized translation gains.

In 2011, although the average US$/Cdn$ exchange rate of 1.01 reflected a stronger relative Canadian dollar over the entire year, the change in the US$/Cdn$ exchange rate from the beginning of the year (1.01) to the end of the year (0.98) impacted the year-end translation of U.S. dollar denominated balances as if the Canadian dollar was relatively weaker.

Economic Sensitivities (1)(2)(3)

The following table illustrates the estimated effects that changes in certain factors would have had on 2011 net earnings and cash flow from operations if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Cash Flow From Operations
Crude oil +US$1.00/bbl	81	108
Natural gas +Cdn$0.10/mcf	(1)	(1)
Light/heavy differential +US$1.00/bbl	43	58
3-2-1 crack spreads +US$1.00/bbl	109	134
Foreign exchange +$0.01 US$/Cdn$	(37)	(150)

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and Condensate all increase by US$1.00/bbl.

(3) Differences between estimates for net earnings and cash flow from operations are due primarily to the impacts of cash taxes in certain jurisdictions.

5. SEGMENT RESULTS AND ANALYSIS

OIL SANDS

Strategy and Operational Update

The Oil Sands business continues to focus on safe, reliable operations that achieve steady production growth while effectively controlling operating costs. We expect our operational excellence initiatives will continuously improve our plant utilization and workforce productivity.

In 2012, Oil Sands Base expects to integrate new mining and upgrading projects that complement its core operations. Oil Sands Base is continuing the ramp up of bitumen production from the NSE, which is expected to reduce mine congestion and lower average haul distances. In addition, Oil Sands Base expects to commission and start up the MNU, which is expected to improve the reliability and availability of its upgrading facilities.

Production growth from the Firebag Stage 3 expansion is on track. Firebag Stage 4 leverages our existing infrastructure and is a smaller project to execute than Stage 3, but is anticipated to bring additional barrels of production equivalent to Stage 3. We expect our portfolio of technology projects will drive improvements and efficiencies in current production and develop future opportunities. This portfolio focuses on both subsurface and surface challenges, such as reducing steam-to-oil ratios and improving the efficiency of steam production and water treatment.

Suncor's transactions with Total E&P closed in March 2011. In order to manage and develop all of the new joint ventures, Suncor created a new business area – Oil Sands Ventures. Throughout 2011, Oil Sands Ventures focused on ensuring the successful restart of the Fort Hills mining and Voyageur upgrader projects, and bringing in operating expertise to complement existing proficiencies and commercial capabilities to effectively manage these new joint ventures. Suncor and the joint venture owners of the Fort Hills, Voyageur upgrader and Joslyn projects have developed a capital program for site preparation and are working towards making decisions regarding the sanctioning of these projects in 2013.

Financial Highlights (1)

Year ended December 31 ($ millions)	**2011**	2010	2009
Gross revenues	**13 001**	9 690	6 744
Less: Royalties	**(799)**	(681)	(645)
Operating revenues, net of royalties	**12 202**	9 009	6 099
Net earnings	**2 603**	1 520	557
Operating earnings (2)	**2 737**	1 379	1 048
Cash flow from operations (2)	**4 572**	2 777	1 251

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands net earnings for 2011 were $2.603 billion, compared to $1.520 billion in 2010. Net earnings for 2011 included an after-tax loss of $99 million on the sale of partial interests in the Voyageur upgrader project and the Fort Hills mining project, and an after-tax write-off of $35 million for third-party pipeline adjustments. Net earnings for 2010 included after-tax gains of $233 million for the change in fair value of commodity derivatives used for risk management, net of realizations, and $51 million for a recovery of royalties pertaining to a change in Suncor's BVM, partially offset by after-tax write-offs of $143 million primarily associated with equipment for an alternative mining and extraction process that was discontinued.

Operating earnings for 2011 were $2.737 billion, compared to $1.379 billion in 2010, and increased primarily due to higher average price realizations and higher production volumes, offset by higher operating expenses and DD&A.

Cash flow from operations for 2011 were $4.572 billion, compared to $2.777 billion in 2010, and increased primarily due to higher margins, which were driven by higher price realizations and higher production volumes.

Operating Earnings

Operating Earnings Reconciliation (1)

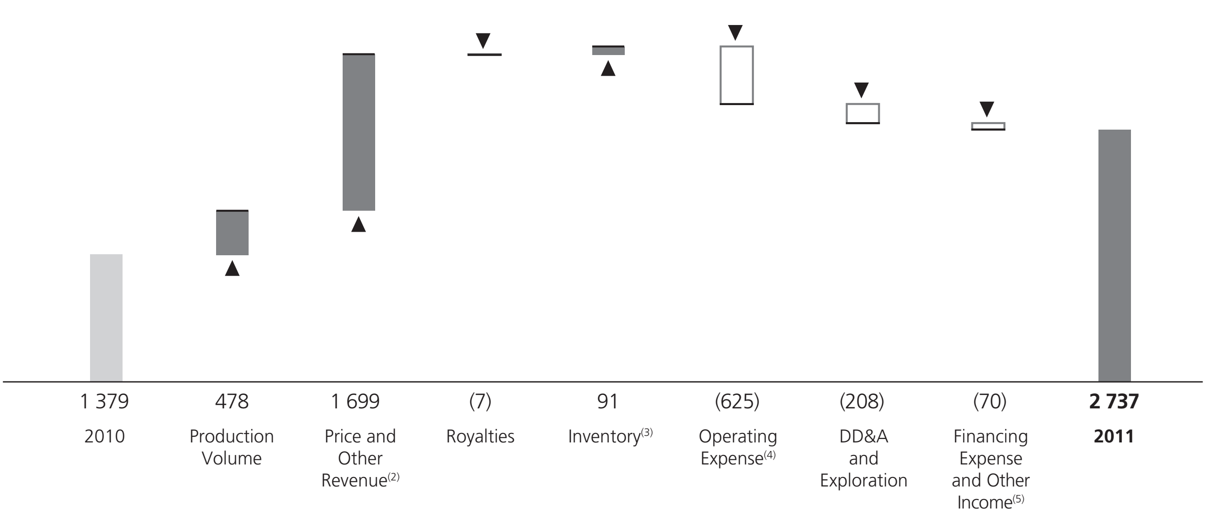
Year ended December 31 ($ millions)	2011	2010	2009
Net earnings as reported	**2 603**	1 520	557
Loss on significant disposals	**99**	—	39
Impairments and write-offs	**35**	143	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(233)	499
Modification of the bitumen valuation methodology	**—**	(51)	50
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)
Costs related to deferral of growth projects	**—**	—	299
Impact of income tax rate adjustments on deferred income taxes	**—**	—	37
Adjustments to provisions for assets acquired through the merger	**—**	—	5
Operating earnings (2)	**2 737**	1 379	1 048

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings(1)

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Includes price realizations before royalties and transportation costs, other operating revenues and the net impacts of sales and purchases of third-party crude.

(3) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor based on production volumes, rather than based on sales volumes.

(4) This factor includes transportation expense, operating, selling and general expense, and project start-up costs.

(5) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Production Volumes

Year ended December 31	**2011**	2010	2009
Oil Sands (mbbls/d)	**304.7**	283.0	290.6
Oil Sands Ventures (mbbls/d)	**34.6**	35.2	16.1
Total (mbbls/d)	**339.3**	318.2	306.7

Production volumes from Oil Sands (excluding Syncrude) in 2011 averaged 304.7 mbbls/d, compared to 283.0 mbbls/d in 2010, and increased mainly due to operational improvements at the company's mining and extraction operations, reflected by a 12% increase in bitumen ore tonnes mined. Production from the first half of 2010 was impacted by two upgrader fires. In 2011, Suncor successfully completed the largest planned maintenance event in its history at its Upgrader 2 facilities, lasting approximately six weeks; the impact of this event on 2011 production was greater than the two relatively smaller planned maintenance events completed in 2010.

Oil Sands achieved a single-month production record of 345,000 bbls/d in December, reflecting higher bitumen output from In Situ operations and an increase in bitumen ore tonnes mined, partially offset by lower bitumen ore grade quality at the Millennium mine face. Suncor anticipates that lower bitumen ore grade quality will continue to impact operations until the start of the fourth quarter of 2012, at which point the bitumen ore grade quality is expected to return to previous levels.

In Situ bitumen production volumes averaged 89.5 mbbls/d in 2011, compared to 85.1 mbbls/d in 2010. Output from Firebag averaged 59.5 mbbls/d in 2011, an 11% increase from 53.6 mbbls/d in 2010. This increase was due mainly to new production starting in the second half of 2011 from the first well pad for the Stage 3 expansion and from new infill wells completed on existing well pads. MacKay River production averaged 30.0 mbbls/d in 2011, down slightly from 2010 production of 31.5 mbbls/d. Overall MacKay River production levels have been at or around nameplate capacity (approximately 30,000 bbls/d) since 2009. The company anticipates that new wells coming on-stream in the fourth quarter of 2011 and throughout 2012, combined with well workovers, will offset natural declines from existing well pairs. Bitumen production from Suncor's In Situ operations exited 2011 at approximately 111,000 bbls/d.

For Oil Sands Ventures, Suncor's share of Syncrude production decreased to 34.6 mbbls/d in 2011, compared to 35.2 mbbls/d in 2010. Production in 2011 was negatively impacted by operational issues with a hydrogen plant following the planned maintenance event in the fall.

Average Price Realizations and Sales Volumes[1]

Year ended December 31	**2011**	2010	2009
Oil Sands ($/bbl)	**88.74**	69.58	61.66
– relative to WTI (Cdn$/bbl)	**(5.35)**	(12.33)	(9.59)
Sales volumes (mbbls/d)	**304.4**	279.3	276.2
Sales mix (sweet/sour) (%)	**36/64**	37/63	47/53
Oil Sands Ventures ($/bbl)	**101.80**	80.93	77.36

(1) Average price realizations are before royalties and net of related transportation costs, and include the impact of realized derivative gains and losses.

Oil Sands sales volumes (excluding Syncrude) increased in 2011, compared with 2010. The sweet/sour sales mix for 2011 (36%/64%) was slightly lower than 2010 (37%/63%). The Upgrader 1 hydrogen plant experienced several outages over the second half of 2010 and into the first half of 2011. The company completed maintenance on these units and, as a result, the sweet/sour sales mix for the fourth quarter of 2011 was 46%/54%.

Average price realizations for Oil Sands sales were $88.74/bbl (WTI less $5.35/bbl) in 2011, compared to $69.58/bbl (WTI less $12.33/bbl) in 2010, and increased mainly due to higher benchmark prices for crude oil. The average price realization for sales relative to WTI improved due mainly to higher differentials for SCO compared to WTI. Suncor's average price realization for Syncrude sales in 2011 was $101.80/bbl, compared to $80.93/bbl in 2010, and was higher due to higher benchmark prices for crude oil and higher differentials between SCO and WTI.

Royalties

Royalties were slightly higher in 2011 than in 2010. Oil Sands royalties are influenced primarily by the valuation for bitumen, which was approximately 10% higher in 2011. In Situ royalties were also higher because MacKay River reached the higher, post-payout phase as determined by regulation in November 2010. These increases were partially offset by increased capital expenditures for royalty-eligible capital expenditures (primarily the TRO_{TM} project). Royalties in 2010 were impacted by the receipt of business interruption insurance proceeds, which were subject to royalty, related to the upgrader fires in 2009 and 2010.

For 2011, Suncor continued to remit royalty payments under its BVM for production from Oil Sands Base operations based on its view of reasonable quality adjustments; however, royalty expense was calculated based on the quality adjustment enacted by the Alberta government in December 2010. Suncor's Royalty Amending Agreement (the Suncor RAA) provides for an arbitration procedure failing settlement of these issues. Suncor filed a Notice of Commencement of Arbitration with the Alberta government on January 29, 2011.

Inventory

The Inventory variance factor was positive because inventories produced during the prior year at relatively lower production costs were sold and replaced by inventories produced during the current year at relatively higher production costs.

Oil Sands Cash Operating Costs [(1)]

Year ended December 31	**2011**	2010	2009
Oil Sands cash operating costs ($ millions)	**4 479**	3 990	3 599
Oil sands cash operating costs ($/bbl)	**40.20**	38.65	33.95

(1) Oil Sands cash operating costs is a non-GAAP financial measure, and is reconciled to operating, selling and general expense in the Non-GAAP Financial Measures Advisories section of this MD&A.

Oil Sands cash operating costs per barrel increased in 2011, averaging $40.20/bbl, compared to $38.65/bbl in 2010, with the impact of higher total Oil Sands cash operating costs (+$4.40/bbl) partially offset by the impact of higher Oil Sands production (-$2.85/bbl). Oil Sands cash operating costs per barrel increased more noticeably in the fourth quarter of 2011, mainly because of the ramp up of the Firebag Stage 3 expansion and higher mining costs necessary to maintain bitumen supply while working through the lower ore grade quality zone at the Millennium mine face and to remove more tonnes of overburden.

Oil Sands cash operating costs increased to $4.479 billion in 2011 from $3.990 billion in 2010. Within this total, In Situ cash operating costs increased significantly compared to 2010, due mainly to higher expenses for labour, maintenance, natural gas and support, most of which was associated with the Firebag Stage 3 expansion. For Oil Sands Base operations, upgrading costs were higher primarily as a result of maintenance related to the restart of the Upgrader 1 hydrogen plant, and mining costs were higher, due mainly to a larger workforce and higher maintenance and rentals to support increased bitumen output.

Expenses and Other Factors

Operating expenses at Syncrude were higher in 2011 than 2010, due primarily to increased maintenance stemming from operational issues, and higher diesel fuel costs, which reflected higher prices and higher overall consumption.

In addition, other operating expenses were lower in 2011 than 2010, primarily due to lower share-based compensation expense and lower costs related to the deferral of growth projects. These decreases were partially offset by higher project start-up costs related to the Firebag Stage 3 expansion and commissioning of the MNU.

The company continues to incur costs related to remobilizing certain growth projects out of "safe mode" after the economic downturn in late 2008 and early 2009. Pre-tax safe mode costs for 2011 were $76 million, compared to $126 million in 2010. Safe mode costs include the costs for maintaining equipment and facilities related to projects still in safe mode, the costs to assess the condition of assets coming out of safe mode, and the costs of remobilizing equipment and personnel.

DD&A expense for 2011 was higher than 2010, due mainly to a larger asset base that is the result of costs capitalized for recently commissioned In Situ assets and significant planned maintenance events in 2010 and 2011.

Other income was lower in 2011 than in 2010, mainly due to insurance proceeds received from Suncor's captive insurance company in 2010 related to the 2009 and 2010 upgrader fires.

Planned Maintenance Events

During the second quarter of 2011, the company successfully completed a six-week planned maintenance event safely and on schedule. The scope of this event, associated with Oil Sands Base Upgrader 2 facilities, was the largest in Suncor's history.

In the second quarter of 2012, the company expects to shut down one coker unit at Upgrader 1. In the third quarter of 2012, the company expects to complete maintenance on the vacuum tower and shut down one coker unit at Upgrader 2. The company is also currently planning to complete maintenance on secondary upgrading units at both Upgrader 1 and Upgrader 2 during 2012.

Arrangements with Total E&P

During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project and increased Total E&P's working interest in the Fort Hills oil sands mining project, and which brought Suncor into the Joslyn oil sands mining project. In consideration for Total E&P acquiring a 49% interest in the Voyageur upgrader project, an additional 19.2% interest in the Fort Hills project, rights to certain knowledge and technology licences, and Total E&P assuming its share of capital expenditures subsequent to the transaction effective date of January 1, 2011, Suncor received $2.662 billion from Total E&P, net of transaction costs. Suncor recorded an after-tax loss of $99 million on the partial disposition of its assets, which included a reduction of $267 million to goodwill that the company allocated to its disposed interests. The after-tax loss was modified in the fourth quarter of 2011 following adjustments finalized during the closing period. In consideration for Suncor acquiring a 36.75% interest in Joslyn and assuming its share of capital expenditures subsequent to the effective date, Suncor paid Total E&P $842 million.

Results for 2010 compared with 2009

Oil Sands net earnings for 2010 were $1.520 billion, compared to $557 million in 2009. Net earnings in 2010 were positively impacted by gains related to the change in fair value of certain risk management derivatives, but negatively impacted by the write-off of mining and extraction equipment. Net earnings in 2009 were negatively impacted by losses related to the change in fair value of certain risk management derivatives, net of realizations, and by costs related to the deferral of growth projects triggered by the general economic downturn in 2008, but positively impacted by a gain related to the merger on the effective settlement of a pre-existing contract with Petro-Canada to upgrade MacKay River bitumen production.

Operating earnings for 2010 were $1.379 billion, compared to $1.048 billion in 2009. The increase was due mainly to higher overall price realizations that reflected higher benchmark prices and a full year of production from Suncor's share in Syncrude. This increase was partially offset by lower production from Oil Sands during the first half of 2010, due mainly to the impacts of the two upgrader fires, lower sweet/sour sales mix that was negatively impacted by the upgrader fires and operational issues with secondary upgrading facilities at Upgrader 1, and higher operating expenses mainly due to the upgrader fires.

Cash flow from operations for 2010 was $2.777 billion, compared to $1.251 billion in 2009. The increase in cash flow from operations was mainly due to the same factors that affected operating earnings.

EXPLORATION AND PRODUCTION

Strategy and Operational Update

Suncor's Exploration and Production operations are comprised primarily of conventional upstream assets that have lower operating costs and require less reinvestment to maintain production than unconventional oil sands assets. Over two-thirds of 2011 production from this segment received prices based on Brent crude, which traded at a significant premium to WTI for much of 2011. As a result, the Exploration and Production segment generated significant cash flow in 2011 despite lower production volumes, and is an important source of funding for Suncor's long-term growth strategy.

Production growth from Exploration and Production is also an important element of Suncor's long-term strategy. The development of the Golden Eagle, Hibernia Southern Extension Unit (HSEU), White Rose Extensions and Hebron all provide what the company believes are attractive opportunities to grow low-cost production and generate future cash flow.

In 2011, Exploration and Production faced many challenges. Operations were suspended for much of the year in Libya and were recently suspended in Syria. Production from Terra Nova was constrained by H_2S issues, and production from the non-operated Buzzard platform experienced periods of lower rates due to operational issues. Suncor continues to see opportunity to further rightsize its asset base by divesting non-core properties in North America Onshore. However, poor market conditions for natural gas assets in Western Canada in 2011 offered limited opportunities that met the company's financial objectives.

For 2012, the effective execution of projects at our offshore assets, such as the dockside maintenance program for Terra Nova, is expected to set the company up for continued success. Exploration activities in the North Sea are expected to be associated with the Beta discovery and the Romeo prospect. Elsewhere, we are directing attention to continued cost reductions and unconventional and liquids-rich plays in our North America Onshore operations, and the restart of production from Libya provides the company with a cautiously optimistic outlook about a full return to business in that country.

Financial Highlights[1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Gross revenues	**6 784**	7 043	2 858
Less: Royalties	**(1 472)**	(1 377)	(554)
Operating revenues, net of royalties	**5 312**	5 666	2 304
Net earnings	**306**	1 938	78
Operating earnings[2]	**1 358**	1 193	150
Cash flow from operations[2]	**2 846**	3 325	1 280

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

Exploration and Production net earnings for 2011 were $306 million in 2011, compared to $1.938 billion in 2010. Net earnings in 2011 were impacted by after-tax impairment charges of $503 million against assets in Libya ($514 million initial impairment, net of $11 million of subsequent impairment reversals) as a result of the shut-in of production and $68 million against certain North America Onshore properties due to decreasing natural gas prices. Net earnings in 2011 were also impacted by a deferred income tax expense adjustment of $442 million pertaining to an increase in the U.K. tax rate on oil and gas profits in the North Sea, an after-tax provision of $31 million pertaining to a royalty dispute covering a period from before the merger, and after-tax losses on disposal of non-core assets of $8 million. Net earnings in 2010 included after-tax gains on disposal of non-core assets of $826 million, an after-tax gain of $166 million for the redetermination of Suncor's working interest in Terra Nova, after-tax impairment charges of $111 million on certain North America Onshore assets mainly due to lower natural gas prices, an after-tax provision for $84 million related to losses on unfavourable natural gas pipeline commitments, and after-tax impairment charges of $52 million on non-core U.K. assets that were sold later in 2010 and the first quarter of 2011.

Operating earnings for 2011 were $1.358 billion, compared to $1.193 billion in 2010. The increase in operating earnings was primarily due to higher average price realizations and lower operating expenses and DD&A, partially offset by lower production volumes, higher royalties and a higher effective tax rate on U.K. earnings.

Cash flow from operations was $2.846 billion in 2011, compared to $3.325 billion in 2010. The decrease in cash flow from operations relative to the increase in operating earnings is due primarily to lower production from assets in 2011 that contributed relatively more to cash flow from operations than operating earnings in 2010. In addition, cash flow from operations in 2010 included the gain from the settlement pertaining to the redetermination of working interests in Terra Nova.

Operating Earnings

Operating Earnings Reconciliation[1]

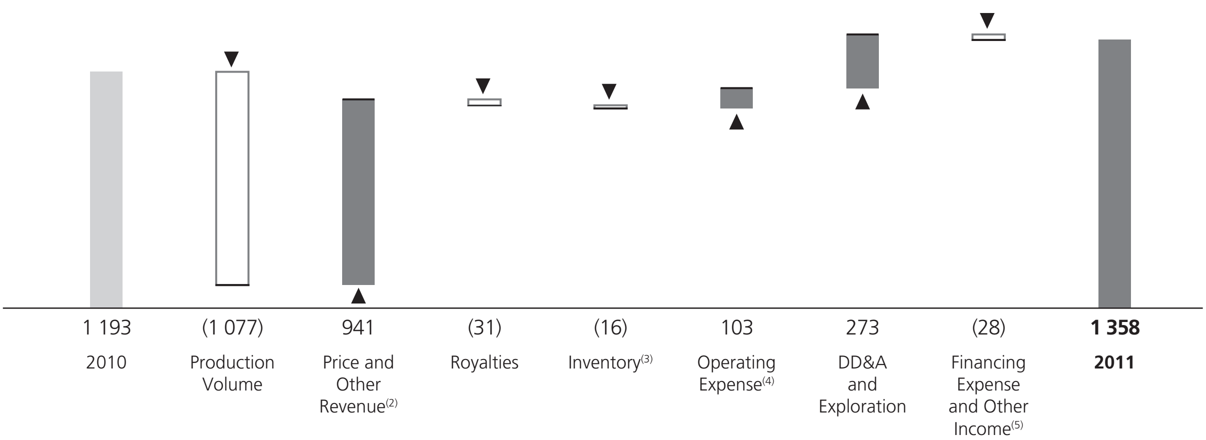
Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**306**	1 938	78
Impairments and write-offs	**571**	163	42
Impact of income tax rate adjustments on deferred income taxes	**442**	—	(19)
Adjustments to provisions for assets acquired through the merger	**31**	84	25
Loss (gain) on significant disposals	**8**	(826)	—
Redetermination of working interest in Terra Nova	**—**	(166)	24
Operating earnings[2]	**1 358**	1 193	150

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Includes price realizations before royalties and transportation costs, other operating revenues and the net impacts of sales and purchases of third-party crude.

(3) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor based on production volumes, rather than based on sales volumes.

(4) This factor includes transportation expense and operating, selling and general expense.

(5) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Production Volumes[1]

Year ended December 31	**2011**	2010	2009
Production volumes			
East Coast Canada (mbbls/d)	**65.6**	68.6	24.3
International (mboe/d)	**76.4**	132.5	50.6
North America Onshore (mmcfe/d)	**388**	575	446
Total production (mboe/d)	**206.7**	296.9	149.3
Mix (liquids/gas) (%)			
East Coast Canada	**100/0**	100/0	100/0
International	**82/18**	87/13	84/16
North America Onshore	**8/92**	9/91	11/89
Total production	**64/36**	63/37	50/50

(1) Production volumes for 2009 represent Suncor's share of production from assets acquired in the merger with Petro-Canada from August 1, 2009 to December 31, 2009.

East Coast Canada production averaged 65.6 mbbls/d in 2011, compared to 68.6 mbbls/d in 2010.

- Production from Terra Nova in 2011 was lower than 2010 by 7.0 mbbls/d and was affected for the entire year by the partial shut-in of certain wells due to the presence of H_2S. Production from Terra Nova increased later in 2011, subsequent to the completion of a new production well and the replacement of a subsea flow line that added back production from certain shut-in wells.
- Production from White Rose in 2011 was higher than 2010 by 4.0 mbbls/d and increased mainly due to higher production from the North Amethyst portion of the White Rose Extensions, which began producing in 2010.
- Production from Hibernia in 2011 was consistent with production in 2010. In 2011, Hibernia achieved first oil from the HSEU. At this time, Suncor does not anticipate significant incremental or sustained production from the HSEU until further development drilling and subsea infrastructure comes on-stream, which is planned for 2014.

International production averaged 76.4 mboe/d in 2011 compared to 132.5 mboe/d in 2010.

- Production from the North Sea in 2011 decreased by 32.3 mboe/d, compared with 2010, with 12.6 mboe/d of the decrease occurring at Buzzard. In 2011, production from Buzzard was impacted by production constraints due to fluctuating rates associated with the replacement of the gas compression cooling system, downtime and capacity constraints on a third-party export pipeline, and other outages that coincided with the commissioning of the fourth platform. The remaining production decrease from the North Sea was due to the disposal of non-core assets in the U.K. and the Netherlands throughout 2010 and into the first quarter of 2011.

- Production from Libya in 2011 averaged 12.1 mbbls/d, compared to 35.2 bbls/d in 2010. Production from Libya was shut in starting in February due to the outbreak of political unrest. As a result of the unrest and subsequent sanctions introduced against the Libyan government, the company declared force majeure under its contractual obligations. Subsequent to the government regime change and the lifting of sanctions, production was restarted later in the year in three of five fields.
- Production from Syria averaged 17.6 mboe/d in 2011, up from 11.6 mboe/d in 2010, primarily because first gas from the Ebla project was achieved in April 2010 and first oil in December 2010. However, unrest in Syria led to international sanctions in December 2011 that prohibited transactions with Suncor's joint venture partner, and, as a result, the company declared force majeure under its contractual obligations and ceased recording further production.
- Production for International in 2010 also included 6.7 mboe/d from the company's Trinidad and Tobago assets, which were divested in the third quarter of 2010.

North America Onshore production for 2011 decreased to 388 mmcfe/d from 575 mmcfe/d in 2010. The decrease was due primarily to disposals of non-core assets throughout 2010 and 2011 that contributed incremental production of approximately 164 mmcfe/d in 2010 and average production of 21 mmcfe/d in 2011. Production from remaining properties decreased approximately 10% compared with 2010, due primarily to natural declines in reservoir performance.

Average Price Realizations(1)

Year ended December 31	**2011**	2010	2009
East Coast Canada ($/bbl)	**108.42**	80.20	76.86
International ($/boe)	**100.89**	74.92	72.65
North America Onshore ($/mcfe)	**4.39**	4.70	4.31

(1) Average price realizations are calculated before royalties and net of transportation costs.

Average price realizations in 2011 for sales of crude oil from East Coast Canada and International assets were significantly higher than 2010, due mainly to higher Brent crude prices.

Average price realizations for North America Onshore production were lower in 2011, mainly due to lower benchmark prices for natural gas at AECO. This decrease was partially offset by higher average price realizations for sales of crude oil and natural gas liquids, due mainly to higher prices for WTI.

Royalties

Royalties were higher in 2011, compared with 2010, due to higher price realizations, partially offset by the shut-in of production in Libya and lower production volumes from North America Onshore.

Expenses and Other Factors

Operating expenses and DD&A were lower in 2011 than in 2010, mainly due to the disposition of non-core assets throughout 2010 and 2011 and the suspension of operations in Libya. Exploration expense also decreased, mainly due to exploration activities in Libya being suspended and exploration well write-offs in 2010 in the Netherlands and Norway portions of the North Sea.

Other factors that impacted operating earnings in 2011, compared with 2010, included the effects of the higher tax rate that the U.K. government enacted in the first quarter of 2011.

Planned Maintenance Events

A dockside maintenance program is scheduled for the Terra Nova FPSO vessel for an estimated 21-week period during the second half of 2012. The company anticipates a return to the field with resumption of production prior to the end of 2012. The planned work includes the replacement of the FPSO water injection swivel and the completion of the replacement of subsea infrastructure to remediate H_2S issues.

An extended, 18-week off-station maintenance program is scheduled to commence in the second quarter of 2012 for the White Rose FPSO, primarily to address issues with the FPSO propulsion system.

During these outages, there will be no production from the respective assets.

Smaller planned maintenance events are scheduled to occur at Hibernia and Buzzard in the third quarter of 2012.

Asset Dispositions

During 2011, the company disposed of certain non-core asset packages from its North America Onshore operations for net proceeds of $164 million, resulting in after-tax gains on disposition of $82 million. These divested assets contributed average production of approximately 35 mmcfe/d in 2010. Current market conditions for further dispositions are limiting opportunities that meet the company's financial objectives.

On March 31, 2011, the company completed its sale of non-core U.K. offshore assets (primarily Scott and Triton). Final net proceeds were £90 million (Cdn$140 million) and the related after-tax loss on disposition was $90 million.

During 2010, the company divested other assets:

- Throughout the year, the company completed the sale of a number of non-core North America Onshore properties for net proceeds of approximately $1.7 billion.
- In the third quarter, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million (Cdn$420 million).
- In the third quarter, the company completed the sale of its assets in Trinidad and Tobago for net proceeds of US$378 million (Cdn$383 million).
- A portion of the sale of the non-core U.K. offshore assets was completed in the fourth quarter for net proceeds of £55 million (Cdn$86 million).

Update on the Impacts of Events in Libya

Following the regime change in Libya in the second half of 2011, Suncor's joint venture in Libya, Harouge Oil Operations BV (Harouge), successfully restarted production in all significant fields and work continues to stabilize production levels. Suncor's share of production exiting December 2011 was approximately 30,000 bbls/d. Suncor remains optimistic about a gradual return to full operations in Libya and is working to remove its EPSAs from force majeure.

In light of the uncertainty surrounding the situation in Libya at the end of the second quarter of 2011, management made an assessment that it may not be able to re-enter Libya for a period of one to two years, if at all, and that any resumption of operations may involve additional remedial expenditure. The company, therefore, determined that its assets in Libya were impaired and recorded charges of $259 million (net of income taxes of $nil) against producing assets in property, plant and equipment, $211 million (net of income taxes of $nil) against exploration and evaluation assets and $44 million (net of income taxes of $nil) against crude oil and materials inventories. Later in the year, the company was able to confirm the existence and sale of crude inventories and reversed impairment charges of $11 million (net of income taxes of $nil).

Suncor has re-engaged with the National Oil Company of Libya to discuss current operations and future plans; however, there is still sufficient unpredictability underlying operating in this region, including the time frame for the ramp up of production, future exploration commitments, and the extent of damage to the company's assets, which has not yet been fully assessed. Therefore, as at December 31, 2011, there have been no further changes in the company's assessment of the impairment recognized in the second quarter.

For further information about the impairment process, see the Accounting Policies and Critical Accounting Estimates section of this MD&A.

Update on the Impacts of Events in Syria

In December 2011, amid continuing unrest in Syria, sanctions were introduced that required Suncor to declare force majeure under its contractual obligations and suspend operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company ceased recording all production and revenue associated with its Syrian assets. If force majeure is lifted in the future, the company expects it will have the right to recover its share of any production occurring during the force majeure period.

Suncor has not received payment for recent production. Suncor believes it is entitled to these receivables and will work with its joint venture partner to receive payment if and when the sanctions are removed. In accordance with GAAP, because of the uncertainty associated with collecting these amounts as a result of the political unrest and sanctions in Syria, Suncor has recorded an after-tax provision of $63 million against these receivables, which represents approximately half of the overall balance outstanding.

Suncor has estimated the net recoverable value of its assets in Syria based on an assessment of expected future net cash flows over a range of possible outcomes. The result of this assessment did not require Suncor to record an impairment charge against its assets in Syria at December 31, 2011. Should the current situation in Syria be resolved in a timely manner, such that sanctions are lifted, PSCs and sales agreements resume unaltered, and payments for sale of hydrocarbons are received, we would expect that the value of Suncor's net assets in Syria would not be impaired. However, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million. For further information about the impairment process, see the Accounting Policies and Critical Accounting Estimates section of this MD&A.

As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million (pre-tax) on certain foreign operations, of which up to $300 million may apply to our assets in Syria.

Results for 2010 compared with 2009

Exploration and Production net earnings in 2010 were $1.938 billion, compared to $78 million in 2009. Net earnings in 2010 included after-tax gains of $826 million on the disposal of non-core assets and an after-tax gain of $166 million for the redetermination of the company's working interest in Terra Nova, partially offset by after-tax impairments of $163 million.

Operating earnings for 2010 were $1.193 billion, compared to $150 million in 2009, and cash flow from operations was $3.325 billion in 2010, compared to $1.280 billion in 2009. All East Coast Canada and International production, and approximately 70% of 2010 North America Onshore production was acquired in the merger with Petro-Canada. Price realizations were higher in 2010 primarily due to higher benchmark prices for Brent crude.

REFINING AND MARKETING

Strategy and Operational Update

In 2011, the integrated network of Suncor's Refining and Marketing segment created significant value through its strategic assets, geographic leverage and product differentiation. The location and reliability of the Edmonton, Sarnia and Commerce City refineries enabled the capture of attractive inland crude differentials related to record high discounts for WTI compared to Brent crude. The integration of these refineries with crude output from Suncor's Oil Sands segment also resulted in lower feedstock costs. In addition, Suncor's strategy of positioning its marketing demands to exceed its refining capacity has enabled the refineries to keep crude throughputs high and spread fixed refining costs over a broader production base.

Suncor's strategy of leveraging high-value internal channels in its Marketing business was also very successful in 2011, with strong sales volumes and margins, boosting segment earnings beyond the refinery gate. Suncor's Petro-Canada branded outlets continue to be a leading retailer by market share in major urban areas of Canada.

For 2012, Refining and Marketing will continue to focus on the safety and reliability of its operations, leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes, and expand the lubricants product offering.

Financial Highlights[1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Operating revenues	**25 713**	20 860	11 851
Net earnings	**1 726**	819	407
Operating earnings[2]			
Refining and Product Supply	**1 413**	532	311
Marketing	**313**	264	144
	1 726	796	455
Cash flow from operations[2]	**2 574**	1 538	921

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Refining and Marketing had net and operating earnings of $1.726 billion in 2011, compared with net earnings of $819 million and operating earnings of $796 million in 2010.

Refining and Product Supply operations contributed $1.413 billion to operating earnings in 2011, a significant increase compared with 2010, primarily due to higher refining margins and the positive impacts of an increasing crude price environment, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories purchased at relatively higher feedstock costs. Marketing operations contributed $313 million to operating earnings in 2011, which was higher than in 2010, due mainly to strong demand and margins in wholesale and lubricants channels.

Cash flow from operations was $2.574 billion in 2011, compared to $1.538 billion in 2010, and increased primarily due to the same factors that affected operating earnings.

Operating Earnings

Operating Earnings Reconciliation [1]

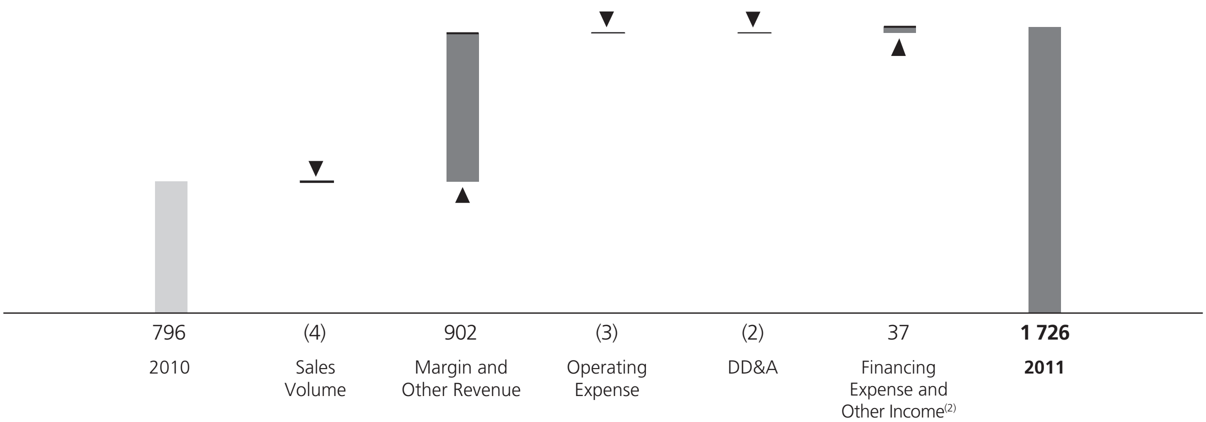
Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**1 726**	819	407
Adjustments to provisions for assets acquired through the merger	—	(23)	67
Impact of income tax rate adjustments on deferred income taxes	—	—	(19)
Operating earnings [2]	**1 726**	796	455

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings [1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Volumes

Year ended December 31	**2011**	2010	2009
Refined product sales (thousands of m^3/d)			
Gasoline	**39.7**	41.1	27.6
Distillate [1]	**30.4**	30.4	18.3
Other	**13.0**	15.8	9.0
	83.1	87.3	54.9
Refinery utilization [2][3] (%)			
Eastern North America	**94**	89	87
Western North America	**91**	95	97
Crude oil processed [4] (thousands of m^3/d)			
Eastern North America	**32.0**	30.5	29.6
Western North America	**32.8**	34.6	33.6

(1) Previously disclosed distillate sales volumes have been adjusted to remove certain volumes that originated from Oil Sands.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

(3) Utilization rates are determined based on refinery capacities in effect prior to January 1, 2012.

(4) 2009 figures have been adjusted to reflect operations subsequent to the merger with Petro-Canada on August 1, 2009, so that they align with refinery utilization rates.

Total sales of refined petroleum products averaged 83,100 m^3/d in 2011, compared to 87,300 m^3/d in 2010. Gasoline sales for 2011 in Eastern Canada decreased compared with 2010, due mainly to lower demand from higher pump prices and the disposal of numerous retail sites in 2010 as mandated by the Canadian Competition Bureau as a result of the merger. There was strong demand for distillate in 2011; however, sales volumes were impacted by a month-long disruption to third-party hydrogen supply at the Edmonton refinery. Sales of lubricants products increased approximately 5% compared to 2010, led by growth in higher margin products.

Refinery utilization in Eastern North America averaged 94% in 2011, compared to 89% in 2010. Refinery utilization in 2010 at the Sarnia refinery was negatively impacted by Enbridge pipeline disruptions.

Refinery utilization in Western North America averaged 91% in 2011, compared to 95% in 2010. Refinery utilization in 2011 for Edmonton was impacted primarily by a month-long disruption to third-party hydrogen supply and a six-week planned maintenance event during the second quarter. Refinery utilization in 2011 for the Commerce City refinery was impacted by a five-week planned maintenance event during the second quarter.

Effective January 1, 2012, Suncor upwardly revised the nameplate capacities of the Commerce City and Montreal refineries, reflecting improvements in reliability and operations. The Commerce City refinery capacity increased from 93,000 bbls/d to 98,000 bbls/d and the Montreal refinery capacity increased from 130,000 bbls/d to 137,000 bbls/d.

Prices and Margins

Refining margins in 2011 were significantly higher than in 2010, due mainly to higher crack spreads and discounted prices for WTI-based crudes that benefited our inland refineries (Sarnia, Edmonton and Commerce City) for most of 2011. Refining margins were also higher in 2011 due to the increasing price environment for crude, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories produced during periods of relatively higher feedstock costs.

Marketing margins for 2011 were strong in wholesale distillate channels, reflecting strong demand, and, for our lubricants operations, reflecting higher demand and increased sales of higher margin products.

Expenses and Other Factors

Operating expenses were slightly higher in 2011 than in 2010, due mainly to volume growth in wholesale channels, which resulted in higher costs for transportation and commissions, partially offset by lower share-based compensation expense. The Financing Expense and Other Income factor was positively impacted by a gain pertaining to the company's investments in marketing entities.

Planned Maintenance Events

Refining and Marketing has several smaller outages planned for 2012, but none as large as the three planned maintenance events that occurred in 2011 at the Sarnia, Edmonton and Commerce City refineries. For 2012, the company's planned maintenance events reflect crude unit maintenance at the Sarnia and Commerce City refineries and minor secondary process unit maintenance at all four refineries.

Results for 2010 compared with 2009

Refining and Marketing net earnings in 2010 were $819 million, compared to $407 million in 2009. Net earnings in 2009 included the negative impact associated with inventory acquired at fair value in the merger.

Refining and Marketing operating earnings in 2010 were $796 million, compared to $455 million in 2009, and were higher primarily as a result of the merger, which more than doubled refinery throughput capacity (from 178,000 bbls/d to 443,000 bbls/d) and increased refined product sales by approximately 60%, compared with 2009. Operating earnings were also higher due to improved operational reliability, strong distillate cracking margins and wider light/heavy and light/sour synthetic crude differentials.

Cash flow from operations in 2010 was $1.538 billion, compared to $921 million in 2009, and increased mainly due to the same factors impacting operating earnings.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Strategy and Operational Update

The Energy Trading business continues to evaluate additional pipeline and storage agreements to support planned increases in production capacity. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with existing arrangements.

Suncor continues to evaluate new opportunities to build its renewable energy portfolio, and has a number of potential wind power project sites in various stages of evaluation.

Financial Highlights (1)

Year ended December 31 ($ millions)	**2011**	2010	2009
Net (loss) earnings	**(331)**	(448)	104
Operating (loss) earnings (2)			
Renewable Energy	**72**	33	40
Energy Trading	**149**	64	44
Corporate	**(346)**	(842)	(529)
Group Eliminations	**(22)**	11	(93)
	(147)	(734)	(538)
Cash flow used in operations (2)	**(246)**	(984)	(653)

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

The net loss for Corporate, Energy Trading and Eliminations in 2011 was $331 million, compared to $448 million in 2010. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate decreasing from 1.01 to 0.98 and resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $161 million. In 2010, the Canadian dollar strengthened in relation to the U.S. dollar, with the exchange rate increasing from 0.96 to 1.01, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $372 million.

The operating loss for Corporate, Energy Trading and Eliminations in 2011 was $147 million, compared with an operating loss of $734 million in 2010. Operating earnings are discussed below.

Operating Earnings

Operating Earnings Reconciliation (1)

Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings (loss)	**(331)**	(448)	104
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)
Impairments and write-offs	**23**	—	—
Merger and integration costs	**—**	79	151
Adjustments to provisions for assets acquired through the merger	**—**	7	—
Impact of income tax rate adjustments on deferred income taxes	**—**	—	5
Operating loss (2)	**(147)**	(734)	(538)

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

Year ended December 31	**2011**	2010	2009
Power generation marketed (gigawatt hours)	**245**	174	177
Ethanol production (thousands of m^3)	**381.5**	206.0	193.7

Suncor's Renewable Energy assets contributed operating earnings of $72 million in 2011, compared to $33 million in 2010, and increased primarily due to higher ethanol production and higher margins for ethanol sales. At the end of January 2011, Suncor completed the expansion of its ethanol plant in Ontario, which doubled production capacity from 200 million litres per year to 400 million litres per year.

Total power generation marketed in 2011 increased to 245 gigawatt hours from 174 gigawatt hours in 2010. In 2011, Suncor commissioned two new wind power projects – the 88-MW, 55-turbine Wintering Hills project in southern Alberta and the 20-MW, eight-turbine Kent Breeze project in southwest Ontario.

Energy Trading

Energy Trading activities contributed operating earnings of $149 million in 2011, compared to $64 million in 2010. Energy trading continued to increase operating earnings, primarily through its heavy crude trading strategies that purchase heavy crude oil in Alberta and transport it to markets with more favourable prices. The price differential between these two locations was considerably wider in 2011, consistent with the discount for WTI compared to Brent.

Corporate

Corporate had an operating loss of $346 million in 2011, compared with an operating loss of $842 million in 2010. The 2010 operating loss included after-tax claims of $243 million for the two Oil Sands Base upgrader fires paid by the company's captive insurance program. The decrease in operating loss was also due to an increase in capitalized interest (approximately $225 million more capitalized after tax) that reduced the amount of borrowing costs that were expensed, and lower share-based compensation expense, partially offset by higher DD&A due to the start of depreciation on Suncor's post-merger systems integration initiative.

In 2011, the company capitalized 85% of its borrowing costs as part of the cost of major development assets and construction projects, compared to 43% in 2010. Subsequent to the completion of transactions with Total E&P, the company resumed capitalizing interest for the Voyageur upgrader project and commenced capitalizing interest for the Fort Hills and Joslyn projects.

Group Eliminations

Group Eliminations reflects the elimination of profit on crude oil sales from Oil Sands, Syncrude and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company determines that the refined products produced from intersegment purchases of crude feedstock have been sold to third parties. In 2011, $22 million of after-tax intersegment profit was eliminated.

Results for 2010 compared with 2009

The net loss for Corporate, Energy Trading and Eliminations for 2010 was $448 million, compared with net earnings of $104 million in 2009. In 2009, the Canadian dollar strengthened in relation to the U.S. dollar as the US$/Cdn$ exchange rate increased from 0.82 to 0.96, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $798 million. However, results from 2009 were more significantly impacted by costs associated with the merger with Petro-Canada and resulting integration costs.

The operating loss for Corporate, Energy Trading and Eliminations for 2010 was $734 million, compared with an operating loss of $538 million in 2009. The higher operating loss in 2010 reflected the claims paid by the company's captive insurance program.

6. FOURTH QUARTER 2011 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2011	2010
Net earnings		
Oil Sands	**790**	484
Exploration and Production	**284**	386
Refining and Marketing	**307**	367
Corporate, Energy Trading and Eliminations	**46**	49
Total	**1 427**	1 286
Operating earnings (loss) (1)		
Oil Sands	**835**	345
Exploration and Production	**372**	275
Refining and Marketing	**307**	366
Corporate, Energy Trading and Eliminations	**(87)**	(178)
Total	**1 427**	808
Cash flow from (used in) operations (1)		
Oil Sands	**1 417**	796
Exploration and Production	**780**	948
Refining and Marketing	**534**	610
Corporate, Energy Trading and Eliminations	**(81)**	(222)
Total	**2 650**	2 132
Production volumes (mboe/d)		
Oil Sands	**356.8**	363.8
Exploration and Production	**219.7**	261.8
Total	**576.5**	625.6

(1) Non-GAAP financial measures. Operating earnings and cash flow from operations are reconciled below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Segment Analysis

Oil Sands

Oil Sands net earnings for the fourth quarter of 2011 were $790 million, compared to $484 million in the fourth quarter of 2010. Operating earnings for the fourth quarter of 2011 were $835 million, compared to $345 million for the fourth quarter of 2010. Cash flow from operations from the fourth quarter of 2011 was $1.417 billion, compared to $796 million in the fourth quarter of 2010. These increases were due primarily to higher margins driven by higher price realizations and improved production and sales of higher margin sweet SCO and diesel, partially offset by higher In Situ operating expenses that were largely associated with the Firebag Stage 3 expansion and higher mining costs required to move more tonnes of ore to maintain bitumen supply while working through the area of lower bitumen ore grade and to remove more tonnes of overburden.

Oil Sands production (excluding Syncrude) increased slightly to 326.5 mbbls/d from 325.9 mbbls/d, reflecting higher bitumen output from Firebag and an increase in bitumen ore tonnes mined. In Situ bitumen production increased to 101.4 mbbls/d from 85.8 mbbls/d, due mainly to the ramp up of production from the first well pad for the Firebag Stage 3 expansion and recently completed infill wells on existing Firebag well pads. For Oil Sands Ventures, Suncor's share of Syncrude production decreased to 30.3 mbbls/d from 37.9 mbbls/d due primarily to operational issues with a hydrogen plant and a coker unit.

Exploration and Production

Exploration and Production net earnings for the fourth quarter of 2011 were $284 million, compared to $386 million in the fourth quarter of 2010. Net earnings in the fourth quarter of 2011 included net after-tax impairment charges of $57 million taken primarily against certain North America Onshore properties due to decreasing prices for natural gas. Net earnings in the fourth quarter of 2010 were positively impacted by after-tax adjustments of $186 million for the redetermination of Suncor's working interest in Terra Nova, but negatively impacted by after-tax impairments and write-offs of $96 million also taken primarily against certain North America Onshore properties due to decreasing prices for natural gas.

Exploration and Production operating earnings for the fourth quarter of 2011 were $372 million, compared to $275 million in the fourth quarter of 2010, and increased primarily due to higher average price realizations, partially offset by the impact of lower production volumes, the provision against accounts receivable related to Syria, and higher royalties that reflected a higher percentage of unsold production from Libya.

Production volumes were 219.7 mboe/d in the fourth quarter of 2011, compared to 261.8 mboe/d in the fourth quarter of 2010. The decrease in production volumes was due mainly to the disposal of non-core assets and lower output from Libya during the restart of production following the lifting of sanctions.

Cash flow from operations was $780 million in the fourth quarter of 2011, which was lower than $948 million for the fourth quarter of 2010, due mainly to 2010 including the gain for the redetermination of Suncor's working interest in Terra Nova.

Refining and Marketing

Refining and Marketing net and operating earnings for the fourth quarter of 2011 were $307 million, compared with net earnings of $367 million and operating earnings of $366 million in the fourth quarter of 2010. Cash flow from operations was $534 million in the fourth quarter of 2011, compared to $610 million in the fourth quarter of 2010.

Sales volumes decreased to 81,600 m^3/d from 89,200 m^3/d. This decrease was primarily due to lower crude throughput at the Edmonton refinery due to a month-long disruption in third-party hydrogen supply. Sales volumes were also lower due to lower demand for heating oil through the wholesale channel in Eastern Canada, due mainly to warmer weather.

Corporate, Energy Trading and Eliminations

Net earnings for this group in the fourth quarter of 2011 were $46 million, compared with net earnings of $49 million in the fourth quarter of 2010. In the fourth quarter of 2011, the Canadian dollar strengthened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate increasing from 0.95 to 0.98 and resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $156 million. In the fourth quarter of 2010, the Canadian dollar strengthened in relation to the U.S. dollar as the exchange rate increased from 0.97 to 1.01, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $252 million.

The operating loss for this group in the fourth quarter of 2011 was $87 million, compared with an operating loss of $178 million in the fourth quarter of 2010. The decrease in operating loss was due mainly to an increase in capitalized interest related to more major projects being under construction. This decrease was partially offset by higher Renewable Energy earnings that reflected higher ethanol production from the plant expansion, higher Energy Trading earnings that reflected price differences between Alberta and U.S. Gulf Coast markets for heavy crude oil, and lower share-based compensation expense.

Operating Earnings[(1)]

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate Energy Trading and Eliminations		Total	
($ millions)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Net earnings as reported	**790**	484	**284**	386	**307**	367	**46**	49	**1 427**	1 286
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**(156)**	(252)	**(156)**	(252)
Impairments and write-offs	**35**	2	**57**	96	**—**	—	**23**	—	**115**	98
Loss (gain) on significant disposals	**10**	—	**—**	(21)	**—**	—	**—**	—	**10**	(21)
Adjustments to provisions for assets acquired through the merger	**—**	—	**31**	—	**—**	(1)	**—**	7	**31**	6
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(48)	**—**	—	**—**	—	**—**	—	**—**	(48)
Redetermination of working interest in Terra Nova	**—**	—	**—**	(186)	**—**	—	**—**	—	**—**	(186)
Modification of the bitumen valuation methodology	**—**	(93)	**—**	—	**—**	—	**—**	—	**—**	(93)
Merger and integration costs	**—**	—	**—**	—	**—**	—	**—**	18	**—**	18
Operating earnings (loss)	**835**	345	**372**	275	**307**	366	**(87)**	(178)	**1 427**	808

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

Cash flow from Operations[1]

Three months ended December 31 ($ millions)	Oil Sands 2011	Oil Sands 2010	Exploration and Production 2011	Exploration and Production 2010	Refining and Marketing 2011	Refining and Marketing 2010	Corporate Energy Trading and Eliminations 2011	Corporate Energy Trading and Eliminations 2010	Total 2011	Total 2010
Net earnings	**790**	484	**284**	386	**307**	367	**46**	49	**1 427**	1 286
Adjustments for:										
Depreciation, depletion, amortization and impairment	**392**	308	**474**	530	**118**	114	**39**	26	**1 023**	978
Deferred income taxes	**270**	140	**(30)**	11	**92**	134	**(10)**	(64)	**322**	221
Accretion of liabilities	**18**	52	**16**	42	**1**	—	**—**	—	**35**	94
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**(179)**	(290)	**(179)**	(290)
Change in fair value of derivative contracts	**—**	(66)	**—**	—	**17**	—	**34**	34	**51**	(32)
Loss (gain) on disposal of assets	**16**	3	**(9)**	(26)	**(5)**	(11)	**—**	38	**2**	4
Share-based compensation	**31**	11	**8**	29	**19**	27	**21**	39	**79**	106
Exploration expense	**—**	—	**—**	10	**—**	—	**—**	—	**—**	10
Other	**(100)**	(136)	**37**	(34)	**(15)**	(21)	**(32)**	(54)	**(110)**	(245)
Cash flow from (used in) operations	**1 417**	796	**780**	948	**534**	610	**(81)**	(222)	**2 650**	2 132
(Increase) decrease in non-cash working capital	**(47)**	(186)	**9**	(74)	**587**	(8)	**(396)**	(120)	**153**	(388)
Cash flow provided by (used in) operating activities	**1 370**	610	**789**	874	**1 121**	602	**(477)**	(342)	**2 803**	1 744

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

7. QUARTERLY FINANCIAL DATA

Financial and Operating Highlights

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2011**	Sept 30 2011	June 30 2011	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010
Total production (mboe/d)	**576.5**	546.0	460.0	601.3	625.6	635.5	633.9	564.6
Oil Sands	**356.8**	362.5	277.2	360.6	363.8	338.3	334.4	234.6
Exploration and Production	**219.7**	183.5	182.8	240.7	261.8	297.2	299.5	330.0
Revenues and other income								
Operating revenues, net of royalties	**10 077**	10 494	9 510	9 256	8 982	7 717	8 174	7 130
Other income [1]	**60**	184	77	132	358	(45)	287	1
	10 137	10 678	9 587	9 388	9 340	7 672	8 461	7 131
Net earnings	**1 427**	1 287	562	1 028	1 286	1 224	540	779
per common share (dollars)								
Basic	**0.91**	0.82	0.36	0.65	0.82	0.78	0.35	0.50
Diluted	**0.91**	0.76	0.31	0.65	0.82	0.78	0.34	0.46
Operating earnings [2]	**1 427**	1 789	980	1 478	808	617	839	370
per common share – basic [2] (dollars)	**0.91**	1.14	0.62	0.94	0.52	0.39	0.54	0.24
Cash flow from operations [2]	**2 650**	2 721	1 982	2 393	2 132	1 630	1 770	1 124
per common share – basic [2] (dollars)	**1.69**	1.73	1.26	1.52	1.36	1.04	1.13	0.72
ROCE [2][3] (%) for the twelve months ended	**13.8**	13.4	11.1	12.5	11.4	9.3	7.9	4.8
Common share information								
Dividend per common share (dollars)	**0.11**	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**29.38**	26.76	37.80	43.48	38.28	33.50	31.33	33.03
New York Stock Exchange (US$)	**28.83**	25.44	39.10	44.84	38.29	32.55	29.44	32.54

(1) In 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Income and Expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. See the Accounting Policies and Critical Accounting Estimates section of this MD&A.

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

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

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2011**	Sept 30 2011	June 30 2011	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010
WTI crude oil at Cushing	US$/bbl	**94.05**	89.75	102.55	94.10	85.20	76.20	78.05	78.70
Dated Brent crude oil at Sullom Voe	US$/bbl	**109.00**	113.40	117.30	104.95	86.50	76.85	78.30	76.25
Dated Brent/Maya FOB price differential	US$/bbl	**5.55**	14.80	14.05	15.65	10.85	9.35	10.45	6.50
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**98.20**	92.50	103.85	88.40	80.70	74.90	75.50	80.95
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**10.45**	17.65	17.65	22.85	18.10	15.65	14.00	9.05
Condensate at Edmonton	US$/bbl	**108.70**	101.65	112.40	98.35	85.70	74.50	82.70	84.65
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.40**	3.70	3.75	3.80	3.60	3.50	3.85	5.35
New York Harbor 3-2-1 crack [1]	US$/bbl	**22.80**	36.45	29.25	19.40	12.20	9.60	12.50	7.95
Chicago 3-2-1 crack [1]	US$/bbl	**19.20**	33.30	29.70	16.45	9.20	10.15	11.05	5.65
Portland 3-2-1 crack [1]	US$/bbl	**26.45**	36.50	29.35	21.40	13.50	16.60	15.50	8.55
Gulf Coast 3-2-1 crack [1]	US$/bbl	**20.40**	33.10	27.30	18.50	8.50	8.60	11.20	7.70
Exchange rate	US$/Cdn$	**0.98**	1.02	1.03	1.01	0.99	0.96	0.97	0.96
Exchange rate (end of period)	US$/Cdn$	**0.98**	0.95	1.04	1.03	1.01	0.97	0.94	0.98

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Trends in Suncor's quarterly earnings results and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major planned maintenance events, such as the one that occurred for Oil Sands Base operations at Upgrader 2 in the second quarter of 2011, and by changes in commodity prices, refining crack spreads and foreign exchange rates, which are summarized above and discussed in the Consolidated Financial Information – Business Environment section of this MD&A.

Over the last eight quarters, Suncor's results were impacted by several important events:

- Results in the first quarter of 2010 were significantly impacted by two upgrader fires that decreased Oil Sands production.

- As part of its strategic business alignment subsequent to the merger with Petro-Canada, Suncor divested a number of non-core assets in its Exploration and Production segment throughout 2010 and 2011. Decreases in production volumes in 2011 are due in part to the disposition of these assets. In addition, the resulting gains and losses on disposition of these assets had one-time impacts on net earnings in the quarters in which they occurred.

Net earnings over the last eight quarters were also affected by other one-time adjustments, including:

- The fourth quarter of 2011 included net after-tax impairments and write-offs of $115 million, taken primarily against North America Onshore assets due to decreasing natural gas prices and against crude inventories due to third-party pipeline adjustments.

- The second quarter of 2011 included impairment charges of $514 million (net of income taxes of $nil, $11 million was later reversed in 2011) against assets in Libya that were associated with the shut-in of production due to political unrest, which also decreased production volumes for 2011.

- The first quarter of 2011 included a $442 million adjustment to deferred income tax expense related to an increase in U.K. tax rates on oil and gas profits in the North Sea.

- The fourth quarter of 2010 included an after-tax gain of $186 million for the redetermination of working interests in the Terra Nova oilfield and an after-tax royalty recovery of $93 million with respect to the modification of the BVM.

- The second quarter of 2010 included an after-tax write-off of $141 million for Oil Sands Base assets that were being used in the development of an alternative extraction process that was discontinued.

8. CAPITAL INVESTMENT UPDATE

The Capital Investment Update section contains forward-looking information. See the Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Capital and Exploration Expenditures

Year ended December 31 ($ millions)	**2011**	2010	2009
Oil Sands	**5 100**	3 709	2 831
Exploration and Production	**874**	1 274	986
Refining and Marketing	**633**	667	380
Corporate, Energy Trading and Eliminations	**243**	360	70
Total capital and exploration expenditures	**6 850**	6 010	4 267
Capitalized interest (included in above figures)	**559**	301	136

Capital and exploration expenditures do not include the purchase of the company's interest in the Joslyn project, which is shown as an acquisition in the audited Consolidated Statements of Cash Flows.

Oil Sands

Oil Sands capital and exploration expenditures were $5.100 billion in 2011. Growth spending in 2011 focused primarily on the following significant projects:

- Capital expenditures for Firebag Stage 3 were $570 million in 2011, bringing total project expenditures to $4.370 billion. In 2011, the company completed construction of all well pads and the central processing facilities. The first well pad began bitumen production in July. The second and third well pads are being steamed, with initial bitumen production expected in the first half of 2012. Peak production from Firebag Stage 3 is anticipated in the next 18 to 24 months.

- Capital expenditures for Firebag Stage 4 were $670 million in 2011, bringing total project expenditures to $1.2 billion. Construction continued on infrastructure, central processing facilities, cogeneration units and the two well pads. Some infrastructure required for Stage 4 was completed as part of Stage 3.

- The company completed construction of the hydrogen plant portion of the MNU, which produced hydrogen in December 2011 and January 2012 before being taken off-line for minor modifications prior to further commissioning. The company expects to have the hydrogen plant operating at design rates by the middle of 2012.

- The company started mining ore from the NSE late in 2011, and operations are expected to ramp up over the next twelve months. The NSE project develops a new mining resource, and is expected to improve productivity of overall mining operations and decrease operating costs by alleviating congestion in the Millennium mining area and reducing average haul distances. The company has applied for regulatory approval to increase the NSE project area. If approved, the expanded area is expected to provide additional recoverable bitumen.

In 2011, the company spent $622 million on the implementation its TRO_{TM} infrastructure project and an additional $110 million on tailings drying facilities. The infrastructure project included the construction of pumping and pipeline facilities for tailings and water transfers across Oil Sands Base mining operations.

Other significant capital expenditures for 2011 focused on the planned maintenance event at Upgrader 2, the acquisition of additional land adjacent to one of our oil sands mining properties, preparation of the NSE, major refurbishments and welding of coker units, the mine train replacement project for Syncrude and the restart of our Fort Hills and Voyageur upgrader projects.

Exploration and Production

Exploration and Production capital and exploration expenditures were $874 million in 2011.

For East Coast Canada operations, capital expenditures focused on the replacement of a flow line for partial H_2S remediation and the drilling and completion of a new production well at Terra Nova, the continued development of the HSEU, the completion (including initial production) of the first of two pilot wells in the West White Rose field that is part of the White Rose Extensions, an exploratory well for the Ballicatters discovery, and front-end engineering and project development activities for Hebron.

For International operations in the North Sea, capital expenditures focused on the commissioning of the fourth platform at Buzzard, installed to remove H_2S in the oil production from some segments of the field, pre-sanction activity and preliminary design for Golden Eagle, which received regulatory and partner approval during the year, exploratory drilling at the Butch prospect offshore Norway where a discovery was made, and the acquisition of new exploration licences offshore Norway (four operated and one non-operated) and the U.K. (one operated and one non-operated).

For International operations in Libya and Syria, capital expenditures were limited in 2011. Operations were suspended in Libya throughout much of 2011. The company completed one oil production well in Syria before suspending the drilling program mid-year because of unrest, and prior to the introduction of sanctions, which resulted in Suncor suspending all operations in Syria in December 2011.

For North America Onshore operations, capital expenditures focused on the development of production wells in the Wilson Creek and Ferrier areas of the Cardium oil formation, and exploration in the Kobes area of the Montney shale gas formation.

Refining and Marketing

Refining and Marketing spent $633 million on capital expenditures in 2011. Expenditures focused on a variety of projects, including one to reduce benzene content in gasoline production at the Commerce City refinery, which is expected to be completed by the second quarter of 2012.

Corporate, Energy Trading and Eliminations

In 2011, the Renewable Energy business completed the construction and commissioning of the Wintering Hills and Kent Breeze wind projects, and the expansion of the ethanol plant.

Corporate capital expenditures focused on Suncor's initiative to integrate pre-merger information systems onto one common platform.

Significant Growth Projects Update

	Description	Cost Estimate ($ millions)	Project Spend to Date ($ millions)	Target Completion	Estimated % Complete Engineering	Estimated % Complete Construction
Operated						
Firebag Stage 3 expansion	62.5 mbbls/d bitumen	4 400	4 370	Q1 2012	100	100
Firebag Stage 4 expansion	62.5 mbbls/d bitumen	2 000 (±10%)	1 189	Q1 2013	99	60
Non-operated (1)						
Golden Eagle	70 mboe/d (gross)	880 (±10%)	64	Q4 2014		

(1) Cost estimate as per the operator of Golden Eagle, Nexen Petroleum U.K. Limited. Estimated completion percentages not provided for non-operated projects.

The table above provides a review and update at December 31, 2011 of major growth projects that have been sanctioned for development by the company. Other growth projects, such as the Fort Hills and Joslyn oil sands mining projects and the Voyageur upgrader, have not yet received a final investment decision by the company's Board of Directors. These projects are discussed under the Other Capital Projects section below.

The Firebag Stage 3 expansion is nearly complete. The company expects to commission the cogeneration units in the first quarter of 2012. The ramp up of production from the Stage 3 expansion is continuing, and the company expects to reach peak production levels during the second half of 2013. Stage 3 facilities have a planned bitumen capacity of 62,500 bbls/d.

The primary focus for growth capital in 2012 will be the Firebag Stage 4 expansion. In 2012, the company anticipates that construction will continue on the two well pads, central processing facilities and cogeneration units, and plans to initiate steaming of the first well pad in the fourth quarter of 2012, so that first oil can be achieved late in the first quarter of 2013. Stage 4 facilities also have a planned bitumen capacity of 62,500 bbls/d.

The field development plan for the Golden Eagle Area Development in the U.K. portion of the North Sea includes stand-alone facilities designed for 70,000 boe/d of gross production. Activity in 2012 for the development of Golden Eagle is anticipated to focus on the construction and fabrication of the topsides and jacket for the fixed gravity base structure (GBS).

There are risks associated with project cost estimates provided by Suncor. Accordingly, actual costs can vary from estimates, and these differences can be material. Some of these risks are described in the Risk Factors section of this MD&A under the heading Project Execution and Partner Risk.

Other Capital Projects

Suncor also anticipates 2012 capital expenditures focused on the following projects and initiatives:

Oil Sands Base

Suncor will continue implementing its TRO_{TM} tailings reclamation technology across Oil Sands Base operations. The infrastructure project is on schedule to be completed by the fourth quarter of 2012. The company also plans to construct more tailings drying facilities.

Other capital spending for Oil Sands Base is expected to focus on sustaining capital investments, which maintain production capacities at existing facilities, and include costs for planned maintenance events, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities.

In Situ

Capital spending is expected to focus on continuing to build well pads at Firebag and MacKay River and continuing the infill well program at Firebag. This activity, separate from the Firebag Stage 3 and Stage 4 expansions, maintains an inventory of future bitumen supply for central processing facilities as older wells experience natural production declines.

Oil Sands Ventures

In 2013, the company plans to present for sanctioning the budget for the combined development of the Voyageur upgrader, Fort Hills and Joslyn projects to Suncor's Board of Directors. For 2012, Suncor anticipates capital expenditures for:

- The Voyageur upgrader project will focus primarily on validating project scope, developing the project execution plan, engineering and progressing site preparation.
- Fort Hills will focus primarily on progressing design basis memorandum engineering and site preparation, and procuring long-lead items.
- Joslyn will focus on further design work, progressing front-end engineering and site preparation.

Capital expenditures in 2012 for Syncrude are expected to focus on the mine train replacement for the Mildred Lake mine, the mine train relocation at the Aurora mine and sustaining maintenance initiatives.

Exploration and Production

The company anticipates that the second pilot well for water injection support in the West White Rose field of the White Rose Extensions will be completed in the second quarter of 2012. Results from the pilot project, along with other ongoing evaluations, will help define the scope of future development for the West White Rose field.

The Hebron project development plan application was submitted to the Canada Newfoundland and Labrador Offshore Petroleum Board on April 15, 2011. In 2012, the company expects front-end engineering to be finalized, detailed design to commence and major construction contracts to be awarded. The company expects a regulatory approval decision in 2012, followed by a sanction decision by joint venture owners.

Other capital expenditures for East Coast Canada operations are expected to focus on development drilling for Terra Nova, Hibernia and White Rose, the water injection swivel replacement for the FPSO and H_2S remediation activity at Terra Nova, the propulsion system maintenance for the White Rose FPSO, and the procurement of subsea equipment for the development of the HSEU.

The company has secured a rig to drill its third appraisal well for the Beta discovery in the Norway portion of the North Sea under the PL375 licence. Drilling is expected to commence in the first quarter of 2012. Suncor has secured a rig to drill an exploration well for the Romeo joint venture prospect in the U.K. portion of the North Sea and also expects to participate in a non-operated exploration well in the Norway portion of the North Sea. The company expects the drilling of both of these wells will commence in 2012.

For North America Onshore operations, the company plans to continue exploration in the Cardium oil formation and Montney shale gas formation.

9. FINANCIAL CONDITION AND LIQUIDITY

Indicators

At December 31 ($ millions, except as noted)	**2011**	2010
Working capital (1)	**786**	1 148
Short-term debt	**763**	1 984
Current portion of long-term debt	**12**	518
Long-term debt	**10 004**	9 829
Total debt	**10 779**	12 331
Less: Cash and cash equivalents	**3 803**	1 077
Net debt	**6 976**	11 254
Shareholders' equity	**38 600**	35 192
Total debt plus shareholders' equity	**49 379**	47 523
Total debt to total debt plus shareholders' equity (%)	**22**	26

(1) Current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt, and current assets and liabilities associated with assets held for sale.

Twelve months ended December 31	**2011**	2010
Return on Capital Employed (%) (1)		
Excluding major projects in progress	**13.8**	11.4
Including major projects in progress	**10.1**	8.2
Net debt to cash flow from operations (2) (times)	**0.7**	1.7
Interest coverage on long-term debt (times)		
Earnings basis (3)	**10.7**	8.8
Cash flow from operations basis (2)(4)	**16.4**	11.7

(1) Non-GAAP financial measure. The calculations for ROCE are detailed in the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Cash flow from operations and metrics that use cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

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

(4) 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, cash and cash equivalents, and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2012 capital spending program of $7.5 billion and meet current and long-term working capital requirements. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, 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 debt capital markets at commercial terms and rates.

For the year ended December 31, 2011, the company's net debt to cash flow from operations measure was 0.7 times, which met management's target of less than 2.0 times.

In 2011, cash and cash equivalents increased $2.726 billion to $3.803 billion, due mainly to higher cash flow from operations and net proceeds from transactions with Total E&P. These increases were partially offset by the company reducing its short-term debt by $1.221 billion, repaying $500 million of Medium Term Notes that came due in 2011, higher capital and exploration expenditures, the return of $500 million to shareholders through the share repurchase plan, and a 10% increase to the company's quarterly dividend (to $0.11 per common share) declared in the second quarter of 2011.

Unutilized lines of credit at December 31, 2011 were approximately $4.428 billion, compared to $5.289 billion at December 31, 2010.

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

($ millions)	
Facility that is fully revolving for a period of one year and expires in 2013	2 000
Facilities that are fully revolving for a period of four years and expire in 2013	203
Facility that is fully revolving for a period of four years and expires in 2016	3 000
Facilities that can be terminated at any time at the option of the lenders	612
Total available credit facilities	5 815
Less:	
Credit facilities supporting outstanding commercial paper	761
Credit facilities supporting standby letters of credit	626
Total unutilized credit facilities	4 428

Financing Activities

Management of debt levels continues to be a priority for Suncor 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, 2011, Suncor's net debt was $6.976 billion, compared to $11.254 billion at December 31, 2010.

Change in Net Debt

($ millions)	
Net debt – December 31, 2010	11 254
Decrease in net debt	(4 278)
Net debt – December 31, 2011	6 976
Decrease in net debt	
Cash flow from operations	9 746
Capital and exploration expenditures and other investments	(6 856)
Proceeds from divestitures, net of costs for acquisitions	2 232
Dividends less proceeds from exercise of share options	(451)
Repurchase of common shares	(500)
Change in non-cash working capital and other	268
Foreign exchange on cash, long-term debt and other balances	(161)
	4 278

The company expects to maintain access to short-term commercial paper borrowing at competitive interest rates by keeping short-term debt at existing levels. During 2011, the company transitioned the majority of its short-term debt to U.S. dollar denominated commercial paper.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is expected not to exceed six months, and all investments are expected to be with counterparties with investment grade debt ratings. As at December 31, 2011, the weighted average term to maturity of the short-term investment portfolio was 31 days. In 2011, the company earned approximately $21 million of interest income on this portfolio.

Suncor's interest on debt (before capitalized interest) in 2011 was $661 million, compared to $704 million in 2010. The decrease in interest reflects the decrease in short-term debt and the repayment of the Medium Term Notes. Fixed-to-floating interest rate swaps on the company's long-term debt in place at December 31, 2010 matured during the year, coinciding with the repayment of the Medium Term Notes.

The company obtained regulatory approval for a Normal Course Issuer Bid (NCIB) with the Toronto Stock Exchange authorizing the purchase for cancellation of up to $500 million of its common shares. The NCIB was announced on August 20, 2011 and began on September 6, 2011. The purchase of $500 million of the company's common shares was completed by December 31, 2011. Pursuant to the NCIB, the company repurchased 17,128,065 shares at an average price of $29.19 per share in 2011. All common shares acquired under the NCIB have been cancelled.

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 exceed 60% of its total debt plus shareholders' equity. At December 31, 2011, total debt to total debt plus shareholders' equity was 22% (December 31, 2010 – 26%). 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 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.

The company's long-term senior debt ratings are:

Long-term Senior Debt	Rating	Long-term Outlook
Standard & Poor's	BBB+	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	Baa2	Positive

The company's commercial paper ratings are:

Commercial Paper	Cdn$ Rating	US$ Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	not rated
Moody's Investors Service	not rated	P-2

In 2011, Moody's upgraded its long-term outlook for senior debt from stable to positive, and Suncor initiated access to the U.S. market for U.S. dollar commercial paper. Otherwise, these credit ratings are unchanged from December 31, 2010.

Outstanding Shares

December 31, 2011 (thousands)	
Common shares	1 558 636
Common share options – exercisable and non-exercisable	59 178
Common share options – exercisable	39 482

As at February 17, 2012, the total number of common shares outstanding was 1,561,658,318 and the total number of exercisable and non-exercisable common share options outstanding was 60,712,741. Once exercisable, each outstanding common share option is convertible into one common share.

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

		Payments Due by Period			
($ millions)	Total	2012	2013 to 2014	2015 to 2016	Thereafter
Fixed- and revolving-term debt (1)	10 287	762	725	—	8 800
Interest payments on fixed-term debt	10 607	596	1 181	1 129	7 701
Finance lease payments	1 026	53	106	109	758
Decommissioning and restoration costs (2)	7 275	426	887	309	5 653
Operating lease agreements, pipeline capacity and energy services commitments	13 633	1 080	2 088	1 680	8 785
Exploration work commitments	608	287	286	35	—
Other long-term obligations (3)	691	335	320	36	—
Total	44 127	3 539	5 593	3 298	31 697

(1) Includes debt that is redeemable at Suncor's option.

(2) Represents the undiscounted amount of obligations associated with land and tailings reclamation and site restoration and decommissioning costs.

(3) Includes the Libya ESPA signature bonus and Fort Hills purchase obligations. See the Other Long-Term Liabilities note to the 2011 audited Consolidated Financial Statements.

In addition to the enforceable and legally binding obligations quantified in the table presented above, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for the purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

Financial Instruments

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars. We use these 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 the revaluation and settlement of derivative contracts used for these risk management activities are recorded as Other Income in the Consolidated Statements of Comprehensive Income. For the year ended December 31, 2011, the pre-tax earnings impact for risk management activities was a loss of $22 million (2010 – pre-tax gain of $89 million).

The company's Energy Trading business uses crude oil, natural gas, refined product and other derivative contracts to generate net earnings, recorded as Other Income. For the year ended December 31, 2011, the pre-tax earnings impact for Energy Trading activities was $301 million (2010 – pre-tax earnings of $106 million).

Year ended December 31 ($ millions)	**2011**	2010
Fair value of contracts at beginning of period	**(74)**	(359)
Fair value of contracts realized during the period	**(239)**	90
Change in fair value during the period	**279**	195
Fair value of derivative contracts at end of period	**(34)**	(74)

During 2011, interest rate swaps classified as fair value hedges relating to $200 million of fixed-rate debt expired. At December 31, 2010, the fair value of the interest rate swaps was an $8 million asset. Suncor is not applying hedge accounting to any derivative contracts as at December 31, 2011.

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

Fair value of derivative contracts at December 31 ($ millions)	**2011**	2010
Accounts receivable	**37**	27
Accounts payable	**(71)**	(93)
	(34)	(66)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these 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 a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging 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. Energy Trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in our 2011 audited Consolidated Financial Statements.

Canadian Federal Budget Proposal

On December 15, 2011, Bill C-13 received Royal Assent and is considered enacted under IFRS. This new legislation includes the limitation of deferral opportunities for corporate partnerships, the change in the future treatment of oil sands lease purchases to Canadian oil and gas property expense from Canadian development expense, and the change in future treatment of pre-production development expenses for oil sands mines to Canadian development expense from Canadian exploration expense.

The company has completed an assessment of the new legislation and expects that, in future years, it will decrease cash flow from operations by accelerating the payment of cash income taxes, but will not have a significant impact on net earnings.

10. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

Suncor's significant accounting policies are described in note 3 to the December 31, 2011 audited Consolidated Financial Statements.

Adoption of IFRS

Effective January 1, 2011, the company began reporting under IFRS. The accounting policies referenced above have been applied in preparing the financial results for the years ended December 31, 2011 and 2010, and the company's opening balance sheet as at January 1, 2010. Detailed reconciliations of amounts reported under Previous GAAP to those presented in this MD&A are provided in the First-Time Adoption of IFRS note to the December 31, 2011 audited Consolidated Financial Statements.

The following table provides a summary reconciliation of consolidated net earnings reported under Previous GAAP to that reported under IFRS:

Year ended December 31, 2010 ($ millions)	
Net earnings, as reported under Previous GAAP	3 571
Adjustments to net earnings:	
Depreciation, depletion, amortization and impairment	274
Gain on disposal of assets	54
Other	17
Provision for deferred income taxes	(87)
Net earnings, as reported under IFRS	3 829

The transition to IFRS included adjustments of $1.632 billion that decreased the carrying amount of Suncor's property, plant and equipment as at January 1, 2010. Suncor applied an IFRS exemption that permitted it to revalue the amount of decommissioning and restoration costs included in the carrying value of the related assets. Suncor also applied an IFRS exemption that permitted it to record certain assets at fair value less costs to sell on the date of transition. The increase in net earnings for 2010 under IFRS compared to Previous GAAP is primarily a result of applying these exemptions to decrease the company's carrying value of property, plant and equipment, and consequently decrease subsequent depreciation of those assets and increase any gains or decrease any losses on the disposal of those assets.

The transition to IFRS also required that the company adopt accounting policies that are different to those previously reported. Changes to accounting policies that may have a significant impact on the company's net earnings or presentation of net earnings include:

- Impairment of assets – Under Previous GAAP, an asset was not impaired if estimates of its recoverable amount using undiscounted expected future cash flows exceeded its net carrying value. Under IFRS, discounted cash flows must form the estimate of recoverable amount, essentially making it more likely that asset impairments will occur. For its 2010 net earnings under Previous GAAP, the company had recorded a pre-tax impairment charge of $220 million that would have been required earlier under IFRS because of this difference in accounting policy. Under IFRS, this impairment was reflected in the opening balance sheet as at January 1, 2010.
- Classification of discontinued operations – Under Previous GAAP, most of the company's 2010 asset dispositions met the definition of discontinued operations, whereas under IFRS only an immaterial amount of the 2010 dispositions met the IFRS definition of discontinued operations. As a result, the company has restated amounts previously reported and is not presenting any discontinued operations for 2010 comparative figures.

Energy Supply and Trading Activities

During 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities Income and Expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Realized and unrealized gains and losses, and the underlying settlement of these transactions, are now recognized and recorded on a net basis in Other Income. Prior period comparative figures have been reclassified for comparability with the current period presentation. Changes to the Consolidated Statements of Comprehensive Income are as follows:

Year ended December 31, 2010 ($ millions, increase/(decrease))	
Energy supply and trading activities income	(2 700)
Other income	102
Energy supply and trading activities expenses	(2 598)
Net earnings	—

Recently Announced Accounting Standards

Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. The standard contains requirements for the classification and measurement of financial assets. The new standard was further revised in October 2010 to include requirements regarding the classification and measurement of financial liabilities. The standard is applicable for Suncor's fiscal year beginning January 1, 2015. The full impact of the standard will not be known until the phases of the IASB's financial instruments project that address hedging and impairments have been completed.

Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principles-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement, and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. Amendments to IAS 27 and IAS 28 reflect requirements in the new standards.

These standards and amendments are effective for Suncor's fiscal year beginning January 1, 2013. The company is currently assessing the impact of these standards and amendments; therefore, the impact of these standards is not known at this time.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for all fair value measurements, clarifies the definition of fair value and enhances the disclosures on fair value measurements. This standard is effective for Suncor's fiscal year beginning January 1, 2013. The company does not anticipate significant changes to its fair value measurements and related disclosures as a result of this standard.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits*, which revise the recognition, presentation and disclosure requirements for defined benefit plans. These amendments are effective for Suncor's fiscal year beginning January 1, 2013. The company does not anticipate significant impacts as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization of stripping costs from the production phase of a mine if an entity can demonstrate that it is probable that future economic benefits will be realized, that costs can be reliably measured, and that the component of the ore body for which access has been improved can be identified. This interpretation is effective for annual periods beginning on or after January 1, 2013. The company does not anticipate significant impacts as a result of this interpretation.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information.

Critical accounting estimates are those estimates that require management to make assumptions about matters that are highly uncertain at the time the estimate is made, and those estimates where changes in critical assumptions that are within a range of reasonably possible outcomes would have a material impact on the company's financial condition, changes in financial condition or financial performance.

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 December 31, 2011 audited Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, amortization, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. Although not reported as part of the company's audited Consolidated Financial Statements, these estimates of reserves and resources can have a significant impact on the Consolidated Financial Statements.

The estimation of reserves involves the exercise of professional judgment. Reserves and resources were evaluated or reviewed as at December 31, 2011 by qualified reserves evaluators in accordance with National

Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2011, which could differ significantly from other points in time throughout the year or in future periods.

Oil and Gas Activities

The company is required to use judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

The costs of drilling exploratory wells are initially capitalized pending the evaluation of commercially recoverable resources. The determination that commercial resources have been discovered requires judgment. If a judgment is made that there are no commercially recoverable reserves, the associated exploration costs are charged to exploration expense. Evaluation costs incurred when management is assessing whether there are commercially recoverable resources and designing development and front-end engineering plans are capitalized. Capitalized costs associated with exploration and evaluation assets are subject to ongoing technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. When management is making this assessment, changes to project economics, quantities of resources, expected production techniques, unsuccessful drilling, and estimated production costs and capital expenditures are important factors. If a judgment is made that extraction of the resources is not commercially viable, the associated exploration and evaluation assets are impaired and charged to net earnings as part of depreciation, depletion, amortization and impairment expense.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, the receipt of the appropriate approvals from regulatory bodies and the company's internal project approval processes. After an oil and gas property is reclassified to property, plant and equipment, all subsequent development costs are capitalized.

Impairment of Assets

A cash-generating unit (CGU) is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of the company's assets into CGUs requires significant judgment with respect to the integration between assets, the use of shared infrastructure, the existence of active markets for the company's products and the way in which management monitors operations.

At the end of each reporting period, the company is required to identify events or conditions that indicate that the net carrying value of a CGU might be impaired. If any such indication exists, the company must complete an impairment assessment for the CGU. A CGU is impaired when the net carrying value of the CGU exceeds management's estimate of the recoverable amount of the CGU, which is the higher of the CGU's fair value less costs to sell and its value-in-use. Fair value less costs to sell is the amount obtainable from the sale of the CGU in an arm's-length transaction between knowledgeable, willing parties, less costs of disposal. In determining fair value less costs to sell, recent market transactions are taken into account if available; however, in the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the future cash flows that the company expects to derive from the CGU. Where management determines that a CGU is impaired, the net carrying value of the CGU is reduced to the estimated recoverable amount, with the difference reported as part of depreciation, depletion, amortization and impairment expense.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment. For 2011, the company completed this review as at July 31, 2011, at which time there were no indications that goodwill was impaired.

At the end of each reporting period, the company must also assess if there are indicators that conditions causing a previous impairment have reversed. Where new estimates of recoverable amount exceed net carrying value, previously recorded impairment adjustments are reversed, up to the amount of the original impairment. An impairment of goodwill cannot be reversed.

For Suncor, the estimated recoverable amount of a CGU is predominantly determined using discounted net future cash flow models. The key assumptions the company uses for estimating future cash flows are future commodity prices, expected production volumes, future operating and development costs, and refining margins. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management. Changes to these assumptions will affect the recoverable amount of a CGU and may require a material impairment to the net carrying value of that CGU.

The company also assesses the impairment of assets when they are classified as held for sale or when they are reclassified from exploration and evaluation assets to property, plant and equipment in the Consolidated Balance Sheets. Assets held for sale are measured at the lower of net carrying value and fair value less costs to sell, which in this situation may also be determined based on expected sale proceeds when an offer has been received.

The following discusses important impairment assessments completed during 2011:

Libya

In the second quarter of 2011, the company recorded impairment charges of $259 million against property, plant and equipment, $211 million against exploration and evaluation assets, and $44 million against inventories pertaining to its operations in Libya, which had been shut-in at that time due to unrest. All impairment charges for Libyan assets are net of income taxes of $nil.

The net recoverable amount was estimated under a value-in-use premise and determined using discounted cash flow models under probability-weighted scenarios representing i) resumption of normal operations after one year; ii) resumption of normal operations after two years; and iii) total loss.

Scenarios involving the company resuming normal operations used current forecasts for the price of crude oil, estimates of operating and development expenditures based on the field redevelopment anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (17%) that represented management's best estimate of the ongoing risk involved with operating in Libya, and management's best estimate of the incremental rebuilding costs to bring operations back on-stream. Management's forecasts for production were based on proved and probable reserves evaluated by external qualified reserves evaluators and risk-adjusted best estimates of contingent resources evaluated by Suncor's internal qualified reserves evaluators, both evaluated as at December 31, 2010. The scenario involving the company not resuming operations in Libya included the effects of the company not paying certain liabilities.

Later in 2011, a change in the Libyan government resulted in the lifting of certain sanctions that were impacting the company's operations in the country, and the company's joint venture partner was able to restart production in three of five fields by the end of 2011. The company started to receive production payments in January 2012, and the joint venture partner confirmed the existence of crude oil inventories that the company had written off, resulting in the company reversing $11 million of impairment charges.

Discussions with the Libyan authorities have commenced on the status of existing contract terms, including production volumes and time frames for future exploration commitments. There is also still unpredictability concerning production levels, expectations about the ramp up of production, and the extent of damage to the company's assets, which has not yet been fully assessed. Therefore, at December 31, 2011, there has been no change in the company's overall assessment of the impairment, and no reversal of impairment has been recognized, except for the $11 million associated with crude inventories noted above.

Syria

As a result of international sanctions announced in December 2011, the company suspended its operations in Syria and ceased recording production or revenues. Suncor performed an impairment test on its assets in Syria that determined that the assets were not impaired at December 31, 2011. The carrying value of the company's net assets in Syria at December 31, 2011 was approximately $900 million.

The net recoverable amount for the company's Syrian assets was estimated under a value-in-use premise and determined using discounted cash flow models, which take into account the long-term nature of the natural gas and light and medium oil reserves associated with these assets, under probability-weighted scenarios representing i) resumption of normal operations after six months; ii) resumption of normal operations after one year; iii) resumption of normal operations after two years; and iv) total loss. This calculation is most sensitive to management's assumption on the timing of the resumption of normal operations. If the probability weighting in the cash flow model was adjusted to reflect a 0% probability of the company resuming normal operations within the next twelve months, the company's Syrian assets may be impaired.

Scenarios involving the company resuming normal operations used current forecasts for the price of commodities, estimates of operating and development expenditures based on the field development anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (17%) that represented management's best estimate of the ongoing risk involved with operating in Syria, and an assumption that the company will receive payment for any production during its absence in Syria. Management's forecasts for production were based on proved and probable reserves evaluated by external qualified reserves evaluators as at December 31, 2011.

North America Onshore

As a result of decreases in price forecasts for natural gas, the company recorded pre-tax impairment charges of $100 million against certain CGUs in the North America Onshore business.

Net recoverable amounts for these CGUs were determined under a fair value less costs to sell premise, and determined using discounted cash flow models based on proved and probable reserves evaluated by external qualified reserves evaluators as at December 31, 2011, third-party price forecasts and a discount rate of 12%.

IFRS Transition Exemption

The company applied an IFRS transition exemption to record certain assets at fair value less costs to sell on the date of transition. The exemption was applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada, and resulted in a total reduction of $906 million in the net carrying value of these assets. These adjustments are not impairments and cannot be reversed because they were applied as part of the IFRS transition. The company's estimates of fair value less costs to sell for these assets required management to make judgments and use assumptions at the transition date that were similar to those described above.

Summary

As at December 31, 2011, the company had $715 million of impairments on assets in the Exploration and Production segment, consisting of $503 million of impairments for Libya assets and $212 million of impairments on North America Onshore assets (2010 – $112 million).

Fair Value of Financial Instruments

To estimate the fair value of financial instruments, the company uses quoted market prices when available, or models that use observable market data. In addition to market information, Suncor incorporates transaction-specific details that market participants would use in a fair value measurement, including the impact of non-performance risk. Inputs used in determining fair value are characterized 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.

Provisions for Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment, including, but not limited to, the reclamation of lands disturbed by mining oil sands, tailings ponds, producing well sites, and crude oil and natural gas processing plants. The provision for such liabilities is recognized only to the extent that there is a legal or constructive obligation associated with the retirement of an asset that the company is 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.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying Suncor's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in costs. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

When these provisions are initially recognized, an equal amount is capitalized as part of the cost of the associated asset and is amortized to expense over the life of the asset.

The fair value of these provisions is estimated by discounting the expected future cash flows using the company's credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expenses, based on the discount rate.

Suncor's provision for decommissioning and restoration costs increased by $1.168 billion in 2011. The most significant change in the provision resulting from a change in estimates was with respect to the expected timing of future reclamation activity, which has accelerated primarily as a result of recent advancements from the use of TRO_{TM}. The provision also increased due to a decrease in the average discount rate (2011 – 4.3%; 2010 – 5.4%) and new liabilities primarily associated with land disturbance in 2011, offset by the settlement of certain liabilities and the impacts of asset disposals.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, expected future cash flows and discount rates.

An onerous contract is one in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it.

A constructive obligation is one where Suncor, by an established pattern of past practice, published policies, or a sufficiently current statement, has indicated that it will accept certain responsibilities and has created a valid expectation in other parties that it will discharge those responsibilities.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2011, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Employee Future Benefits

The company provides benefits to employees and retired employees, including pensions and other post-retirement benefits. The obligations and costs of defined benefit pension and other post-retirement benefit plans are determined based on 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, the return on plan assets, mortality rates and future medical costs. The accrued net benefit liability is reported as other long-term liabilities in the Consolidated Balance Sheets.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented. Actuarial gains and losses are recognized in other comprehensive income in the Consolidated Statements of Comprehensive Income in the period incurred.

Income Taxes

The determination of the company's income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make other judgments, including those about deferred income taxes that are discussed below.

Management believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

A taxable or a deductible temporary difference may exist when there is a difference between the carrying value of an asset or liability and its respective tax basis. The reversal of deductible temporary differences results in deductible amounts when determining taxable income in future periods. The reversal of taxable temporary differences results in taxable amounts when determining taxable income of future periods.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

11. RISK FACTORS

The company is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to the assets and activities of Suncor. The company's enterprise risk committee, comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of the company's businesses or functions to meet or support a Suncor objective. The following provides a list of some of the risk factors relating to Suncor and its operations.

Commodity Price Volatility

Our financial performance is closely linked to prices for crude oil in our upstream businesses and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream businesses, where natural gas is both an input and output of production processes. The values for all of these commodity prices can be influenced by global and regional supply and demand factors.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), political developments, compliance or non-compliance with quotas imposed on members of the Organization of Petroleum Exporting Countries (OPEC), access to markets for crude oil, and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Suncor anticipates higher production of non-upgraded bitumen in future years, due mainly to expansion at Firebag. Due to its low viscosity, bitumen is blended with a light diluent or synthetic crude oil and sold as a heavy crude oil. The markets for heavy crude oil are more limited than those for light crude, making them more susceptible to supply and demand changes. Heavy crude oil receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield, and the higher cost to transport the more viscous product on pipelines. The price differential between light crude and WCS is particularly important for Suncor. WCS is a pool of heavy crude oil and blended bitumen production from Western Canada. The market price for WCS is influenced by regional supply and demand factors, including the availability and price of diluent, and by the availability and cost of accessing primary markets through pipeline systems. Future price differentials are uncertain and widening light/heavy differentials could have a negative impact on our business, especially price realizations for bitumen that Suncor is unable to upgrade.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources.

All of these factors are beyond our control and can result in a high degree of price volatility.

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term, with the possibility that crude oil and refined petroleum products prices could revert to the low levels experienced in 2008 and 2009. A prolonged period of low prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production on some properties or include an impairment of carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of greenhouse gas (GHG) and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases 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.

Changes in government policy or regulation have a direct impact on Suncor's business, financial condition, results of operations and cash flow, as evidenced by such initiatives as the Alberta government's royalty review program in 2007, and, more recently, by trade sanctions in Libya and Syria imposed by Canadian and other international governments, and increased production taxes in the U.K. Changes in government policy or regulation can also have an indirect impact on Suncor, such as opposition to new North American pipeline systems, such as Keystone XL, or incrementally over time through increasingly stringent environmental regulations or unfavourable income tax and royalty regimes. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other principal risks of Suncor, including environmental or safety non-compliance and permit approvals.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on our business, financial condition, results of operations and cash flow by impacting the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor. 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. Failure to comply with environmental regulation may result in the imposition of significant 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.

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;
- The use of hydraulic fracturing to assist in the recovery and production of oil and natural gas;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions;
- U.S. state or federal calculation and regulation of fuel life-cycle carbon content; and
- Regulation or policy by foreign governments or other organizations to limit purchases of oil produced from unconventional sources, such as the oil sands.

Climate Change Regulation

Future laws and regulations may impose significant liabilities on failure to comply with their requirements; however, Suncor expects the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the carbon dioxide (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.

As part of our ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in our evaluation of future projects, based on our current understanding of pending and possible GHG 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. In the future, 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 a price range of $15-$45 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

Although Suncor does not actively market into California, the implications of other states or countries adopting Low Carbon Fuel Standard legislation could pose a significant barrier to our exports of oil sands crude if the importing jurisdictions do not acknowledge efforts undertaken by the oil sands industry to meet the emissions intensity reductions legislated by the Government of Alberta.

In general, there remains uncertainty around the outcome and impacts of proposed or potential future climate change and other related environmental regulation. 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 Canadian 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. At this time, the company does not believe it is possible to predict the nature of any requirements or the impact on Suncor's business, financial condition, results of operations and cash flow. The impact of developing regulations cannot be quantified at this time given the current lack of detail on how systems will operate.

Land Reclamation

There are risks associated specifically with our ability to reclaim tailings ponds containing mature fine tailings with TRO_{TM} or other methods and technologies. Suncor expects that TRO_{TM} will help the company reclaim existing tailings ponds. The success of TRO_{TM} or any other methods of technology and the time to reclaim tailings ponds could increase or decrease our decommissioning and restoration cost estimates. Our failure or inability to adequately implement our reclamation plans, including our planned implementation of TRO_{TM}, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. In recent years, Suncor has increased collaboration with other participants in the oil sands industry to share technology and knowledge and to research alternative methods for tailings management.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs, changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. Some of the issues where settlement with regulatory bodies may cause royalties expense or royalties payable to differ materially from provisions currently recorded include:

- For Suncor's mining operations (not including Syncrude), the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted, which modified the BVM for additional quality and transportation adjustments. For the years 2009 to 2010, Suncor filed non-compliance notices with the Alberta government, citing that reasonable quality adjustments in the determination of the Suncor BVM were not considered by the Alberta government as permitted by Suncor's RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The owners of the Syncrude joint venture have also filed a non-compliance notice in respect of the determination of the bitumen value under its 2008 agreements with the Alberta government.
- Suncor has also appealed the disallowance of certain costs under the New Royalty Framework in Alberta and certain costs under royalty agreements in Newfoundland and Labrador, such as insurance premiums.

The final determination of these matters may have a material impact on royalties payable to the respective governments and the company's royalties expense.

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 and other uncertainties arising from foreign government sovereignty over the company's international operations, 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;
- Compliance with existing and emerging anti-corruption laws, including the Foreign Corrupt Practices Act of the United States, the Corrupt Foreign Officials Act of Canada, and the United Kingdom Bribery Act;
- Renegotiation of contracts with governmental entities and quasi-governmental agencies;
- Changes in laws and policies governing operations of foreign-based companies; and
- Economic and legal sanctions (such as restrictions against countries experiencing political unrest, or countries that other governments may deem to sponsor terrorism).

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. In addition, 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.

In 2011, operations in both Libya and Syria were suspended as a result of the outbreak of political unrest and the resulting sanctions imposed by international governments. Discussions with the Libyan authorities continue on the status of existing contract terms, including production volumes and exploration commitments. There is still sufficient unpredictability underlying operations in this region, including the ramp up of production, the sustainability of current production rates and the extent of damage to the company's assets, which has not yet been fully assessed. As a result, there is no assurance that production will return to previous levels or continue at current levels.

In response to sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Suncor's assessment of the situation as at December 31, 2011 did not require the company to record an impairment charge against its assets in Syria; however, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. There is no assurance as to when Suncor's production from Syrian assets will resume or return to previous levels. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and 3% of the company's cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or collateral damage of, an act of terror, political violence or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

Environmental Health and Safety (EHS) Regulatory Non-Compliance

The company is required to comply with a large number of EHS regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, as described in the Industry Conditions – Environmental Regulation section of the 2011 AIF. Failure to comply with these regulations may result in the imposition of fines and penalties, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on our business, financial condition, results of operations and cash flow. Compliance can be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Operational Outages and Major Environmental or Safety Incidents

Each of our primary operating segments – Oil Sands, Exploration and Production, and Refining and Marketing – demand significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carry the additional economic risk associated with operating reliably or enduring a protracted operational outage. These businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, non-government organizations, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, civil suits or charges against the company.

Generally, our operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions, and the migration of harmful substances such as oil spills, gaseous leaks, or a release of tailings into water systems, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment, the environment, and information technology systems and related data and control systems.

The reliable operation of production and processing facilities at planned levels and our ability to produce higher value products can also be impacted by failure to follow operating procedures or operate within established operating parameters, equipment failure through inadequate maintenance, unanticipated erosion or corrosion of facilities, manufacturing and engineering flaws, and labour shortage or interruption. We are also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of our business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. In addition, the unavailability of the information systems or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased operating costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security could adversely affect our business and results of 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. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers or third-party suppliers may limit our availability to deliver feedstock. All of these events could have negative implications on sales and cash from operating activities.

For Suncor's Oil Sands operations, mining oil sands ore, extracting bitumen from mined ore, producing bitumen through in situ methods, and upgrading bitumen into SCO 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. 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, Suncor has two upgrader facilities that include three secondary upgrading units, which provide us with the flexibility to conduct periodic planned maintenance events on one facility while continuing production from the other.

For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of H_2S), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks.

Our Exploration and Production 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 and other extreme weather conditions. 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 consequence of catastrophic events, such as blow-outs, occurring in offshore operations can be more difficult and time-consuming to remedy. 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. Successful remediation of these events may be adversely affected by the water depths, pressures and cold temperatures encountered in the ocean, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate technology to resolve the event. Damage to the environment, particularly through oil spillage or extensive, uncontrolled fires or death, could result from these offshore operations. Our offshore operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations.

In particular, East Coast Canada operations can be impacted by winter storms, pack ice, icebergs and fog. During the winter storm season (typically October to March), we may have to reduce production rates at our offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. During the spring, pack ice and icebergs drifting in the area of our offshore facilities have resulted in precautionary shut in of FPSO production and drilling delays. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Our Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines, other distribution facilities and service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on Suncor's 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. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from offshore operations. Suncor also has a captive insurance entity to provide additional business interruption coverage for potential losses.

Project Execution and Partner Risk

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base, the occurrence of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project execution risk consists of three related primary risks:

- Engineering – a failure in the specification, design or technology selection;
- Construction – a failure to build the project in the approved time and at the agreed cost; and
- Commissioning and start-up – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Management believes the execution of major projects presents issues that require prudent risk management. Suncor may provide cost estimates for major projects at the conceptual stage, prior to commencement or completion of the final scope design and detailed engineering necessary to reduce the margin of error of such cost estimates. Accordingly, actual costs can vary from estimates, and these differences can be material. Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- 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.

Other entities operate a portion of the assets in which Suncor has ownership interests. Suncor's dependence on its partners – the operator and other working interest owners for these assets – and its limited ability to influence operations and associated costs could materially adversely affect Suncor's business, financial condition, results of operations and cash flow. The success and timing of Suncor's activities on assets operated by others depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These partners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting jointly owned assets may require agreement among the partners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While the partners generally seek consensus with respect to major decisions concerning the direction and operation of the assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by either party may affect our participation in the operation of such assets, our ability to obtain or maintain necessary licences or approvals, and the timing for undertaking various activities.

Corporate Reputation

The public perception of integrated oil and gas companies and their operations may pose issues related to development and operating approvals or market access for products, which may have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Development of the oil sands has figured prominently in recent political, media and activist commentary on the subjects of pipeline transportation, climate change, GHG emissions, water usage and environmental damage, which may directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- Creating significant regulatory uncertainty that challenges economic modelling of future projects and potentially delays sanctioning;
- Motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing

the cost of construction, operation and abandonment; and

- Compelling legislation or policy that limits the purchase of crude oil produced from the Athabasca oil sands by governments and other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns such as those raised above may also harm our corporate reputation and limit our ability to transport our products or access land and joint venture opportunities in other jurisdictions throughout the world. Investors may respond by applying a discount to Suncor's shares, thereby diminishing the company's value, or may hinder Suncor in its ability to influence government policy.

Permit Approvals

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project.

Failure to obtain regulatory approvals, or failure to obtain them on a timely basis or 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 Suncor's business, financial condition, results of operations and cash flow.

Skills and Resource Shortage

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to the growth of the oil sands industry and higher crude oil prices. The increasing age of our existing workforce adds further pressure to this situation. Materials may also 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.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to balance these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate screening of project requests or consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that these objectives may exceed Suncor's capacity to adopt and implement change.

Cost Management

Production from oil sands through mining, upgrading and in situ recovery is, relative to most major conventional hydrocarbon reserves, a higher cost resource to develop and produce. There is also a perception among many stakeholders that the oil sands industry, including Suncor, has little ability to control costs. Suncor is exposed to the risks of growing or uncontrollable operating costs, which could reduce profitability and cash flow that might otherwise be directed towards growth or dividends, and major project capital costs, which could constrain Suncor's ability to execute high quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage, the long-term success of existing and new in situ technologies, and the geology and reserves characterization of in situ reserves that can lead to higher steam-to-oil ratios and lower production.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our most recent Annual Information Form/Form 40-F, filed with securities regulators.

12. OTHER ITEMS

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2011, Suncor's 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, 2011, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) to 15d-15(f)) that occurred during 2011 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 company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

As a result of past unrest in Libya and current events in Syria, Suncor is not able to monitor the status of all of its facilities, including whether certain facilities have suffered damages. Suncor has assessed and is continually monitoring the control environment in these countries and does not consider the changes to have a material impact on the company's overall internal control over financial reporting.

The effectiveness of our internal control over financial reporting as at December 31, 2011 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, 2011.

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

CORPORATE GUIDANCE

Detailed guidance on the company's outlook for 2012 production, capital expenditures and other items can be found in Suncor's 2011 Annual Report, available on www.sedar.com, and Suncor's corporate guidance available on its website at www.suncor.com/guidance.

13. NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, ROCE and Oil Sands cash operating costs – are not prescribed by 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 the 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 financial measure that adjusts net earnings for significant items that are not indicative of operating performance. 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.

Prior period operating earnings have been restated in this MD&A. In the first quarter of 2011, three operating earnings adjustments – mark-to-market valuation of stock-based compensation, project start-up costs and costs related to the deferral of growth projects – were eliminated from the operating earnings reconciliation due to their relatively minor impact on operating earnings, except for the after-tax impact of $299 million for costs related to the deferral of growth projects in the Oil Sands segment, which was not eliminated from 2009 operating earnings as an operating earnings adjustment. Less significant individual gains and losses on disposals were also removed from operating earnings reconciling items reported in 2010. Finally, adjustments to net earnings for the transition to IFRS also had an impact on operating earnings and existing operating earnings adjustments.

The following is a reconciliation of operating earnings as reported in Suncor's MD&A dated February 24, 2011 to operating earnings as reported in this MD&A:

Year ended December 31 (1)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate Energy Trading and Eliminations		Total	
($ millions)	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009
Operating earnings (loss), as previously reported (2)	1 535	1 116	1 124	171	782	473	(709)	(480)	2 732	1 280
Removal of operating earnings adjustments:										
Mark-to-market valuation of stock-based compensation	(31)	(28)	(23)	(21)	(30)	(17)	(19)	(58)	(103)	(124)
(Loss) gain on significant disposals	(4)	—	—	—	26	—	—	—	22	—
Project start-up costs	(55)	(40)	(3)	—	—	—	—	—	(58)	(40)
Costs related to deferral of growth projects	(94)	—	—	—	—	(1)	—	—	(94)	(1)
IFRS adjustments:										
Net earnings	28	—	218	—	18	—	(6)	—	258	—
Operating earnings reconciling items:										
Impairments and write-offs	—	—	(85)	—	—	—	—	—	(85)	—
Gain on significant disposals	—	—	(38)	—	—	—	—	—	(38)	—
Operating earnings (loss), as restated in this MD&A	**1 379**	**1 048**	**1 193**	**150**	**796**	**455**	**(734)**	**(538)**	**2 634**	**1 115**

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Operating earnings (loss) includes amounts classified as discontinued operations in 2010 under Previous GAAP.

The following is a reconciliation of net earnings to operating earnings for Suncor's last five years of operations. Operating earnings for 2007 to 2009 are reported under Previous GAAP and have been adjusted from operating earnings previously reported for the removal of project start-up costs and mark-to-market valuation of stock-based compensation.

($ millions)	**2011**	2010	2009	2008	2007
Net earnings as reported	**4 304**	3 829	1 146	2 137	2 983
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)	852	(215)
Impairments and write-offs	**629**	306	42	—	—
Impact of income tax rate adjustments on deferred income taxes	**442**	—	4	—	(427)
Loss (gain) on significant disposals	**107**	(826)	39	—	—
Adjustments to provisions for assets acquired through the merger	**31**	68	97	—	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(233)	499	(372)	—
Redetermination of working interests in Terra Nova	**—**	(166)	24	—	—
Modification of the bitumen valuation methodology	**—**	(51)	50	—	—
Merger and integration costs	**—**	79	151	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)	—	—
Costs related to deferral of growth projects	**—**	—	299	—	—
Operating earnings	**5 674**	2 634	1 115	2 617	2 341

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. The following is a reconciliation of ROCE for Suncor's last five years of operations. ROCE for 2007 to 2009 are reported under Previous GAAP.

Year ended December 31 ($ millions, except as noted)		**2011**	2010	2009	2008	2007
Adjustments to net earnings						
Net earnings		**4 304**	3 829	1 146	2 137	2 983
Add after-tax amounts for:						
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt		**161**	(372)	(798)	852	(215)
Net interest expense		**83**	327	289	—	36
	A	**4 548**	3 784	637	2 989	2 804
Capital employed – beginning of twelve-month period						
Net debt		**11 254**	13 516	7 226	3 248	1 849
Shareholders' equity		**35 192**	32 485	14 523	11 896	9 084
	D	**46 446**	46 001	21 749	15 144	10 933
Capital employed – end of twelve-month period						
Net debt		**6 976**	11 254	13 377	7 226	3 248
Shareholders' equity		**38 600**	35 192	34 111	14 523	11 896
		45 576	46 446	47 488	21 749	15 144
Average capital employed (1)	B	**44 956**	46 075	35 128	18 447	13 039
ROCE – including major projects in progress (%)	A/B	**10.1**	8.2	1.8	16.2	21.5
Average capitalized costs related to major projects in progress	C	**12 106**	12 890	10 655	5 149	3 454
ROCE – excluding major projects in progress (%)	A/(B-C)	**13.8**	11.4	2.6	22.5	29.3

(1) For 2009 to 2011, average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. For 2007 and 2008, average capital employed is calculated on the basis of a simple average (B+D)/2. This change in calculation was made as a result of the significant capital employed acquired in the merger with Petro-Canada in 2009. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Cash Flow from Operations

Cash flow from operations is a non-GAAP financial measure that adjusts a GAAP measure – Cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, fluctuations for the timing or payment of risk management positions, offshore feedstock purchases, and fuel and income taxes, which management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)[1]	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Net earnings (loss)	**2 603**	1 520	557	**306**	1 938	78	**1 726**	819	407
Adjustments for:									
Depreciation, depletion, amortization and impairment	**1 374**	1 310	922	**2 035**	1 978	1 032	**444**	440	317
Deferred income taxes	**895**	487	(643)	**354**	196	(96)	**494**	269	99
Accretion of liabilities	**85**	130	111	**69**	103	43	**3**	2	1
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**—**	(316)	960	**—**	—	—	**3**	—	(14)
Loss (gain) on disposal of assets	**122**	14	70	**31**	(998)	(20)	**(16)**	(30)	16
Share-based compensation	**(35)**	55	90	**(4)**	24	31	**(21)**	39	35
Exploration expense	**—**	—	—	**28**	96	183	**—**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)	**—**	—	—	**—**	—	—
Other	**(472)**	(423)	(378)	**27**	(12)	29	**(59)**	(1)	60
Cash flow from (used in) operations	**4 572**	2 777	1 251	**2 846**	3 325	1 280	**2 574**	1 538	921
(Increase) decrease in non-cash working capital	**(676)**	(890)	(202)	**398**	(320)	(78)	**600**	(260)	(270)
Cash flow provided by (used in) operating activities	**3 896**	1 887	1 049	**3 244**	3 005	1 202	**3 174**	1 278	651

	Corporate, Energy Trading and Eliminations			Total		
Year ended December 31 ($ millions)[1]	**2011**	2010	2009	**2011**	2010	2009
Net earnings (loss)	**(331)**	(448)	104	**4 304**	3 829	1 146
Adjustments for:						
Depreciation, depletion, amortization and impairment	**99**	75	35	**3 952**	3 803	2 306
Deferred income taxes	**(99)**	(201)	(85)	**1 644**	751	(725)
Accretion of liabilities	**—**	—	—	**157**	235	155
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)	(858)	**183**	(426)	(858)
Change in fair value of derivative contracts	**(43)**	31	34	**(40)**	(285)	980
Loss (gain) on disposal of assets	**(1)**	39	—	**136**	(975)	66
Share-based compensation	**(42)**	(5)	106	**(102)**	113	262
Exploration expense	**—**	—	—	**28**	96	183
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	**—**	—	(438)
Other	**(12)**	(49)	11	**(516)**	(485)	(278)
Cash flow from (used in) operations	**(246)**	(984)	(653)	**9 746**	6 656	2 799
(Increase) decrease in non-cash working capital	**(80)**	300	326	**242**	(1 170)	(224)
Cash flow provided by (used in) operating activities	**(326)**	(684)	(327)	**9 988**	5 486	2 575

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

The following is a reconciliation of cash flow from operations for Suncor's last five years of operations. Cash flow from operations for 2007 to 2009 is reported under Previous GAAP.

($ millions)	**2011**	2010	2009	2008	2007
Cash flow provided by operating activities	**9 988**	5 486	2 575	4 462	3 893
(Decrease) increase in non-cash working capital	**(242)**	1 170	224	(405)	144
Cash flow from operations	**9 746**	6 656	2 799	4 057	4 037

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures that adjust operating, selling and general expense for significant items that do not reflect production costs for Oil Sands that are within the company's control or that do not directly affect routine production activities. Management uses cash operating costs to evaluate operating performance because management believes it provides better comparability between periods.

($ millions)	**2011**	2010	2009
Operating, selling and general expense (1)	**5 169**	4 537	4 277
Less: Syncrude-related operating expenses	**(529)**	(473)	(199)
Less: Other non-production costs (2)	**(299)**	(201)	(517)
Other adjustments (3)	**138**	127	38
Oil Sands cash operating costs	**4 479**	3 990	3 599
Oil Sands cash operating costs ($/bbl)	**40.20**	38.65	33.95

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization and deferral of growth projects, and the expense recognized as part of a non-monetary arrangement involving a third-party processor.

(3) Other adjustments include the effects of changes in inventory valuation, the accretion of liabilities for reclamation and restoration provisions, and the cost of purchased diluent.

Cash operating costs have also been restated for the transition to IFRS. The following table reconciles amounts previously reported to those presented in this MD&A:

	Year ended December 31, 2010	
	$ millions	$/bbl
Oil Sands cash operating costs, as previously reported	4 012	38.85
IFRS adjustments:		
Accretion of liabilities	(16)	
Operating, selling and general expense	(6)	
Oil Sands cash operating costs, as restated in this MD&A	3 990	38.65

14. ADVISORY – FORWARD-LOOKING INFORMATION

This MD&A 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 information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources 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. In addition, all other 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 or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the 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", "continue" and similar expressions.

Forward-looking statements in this MD&A include references to:

Suncor's expectations about production volumes and the performance of its existing assets, including:

- *Lower bitumen ore grade quality at the Millennium mine face will impact operations until the start of the fourth quarter of 2012, at which point the bitumen ore grade quality is expected to return to previous levels;*
- *New wells coming on-stream at MacKay River in the fourth quarter of 2011 and throughout 2012, combined with well workovers, will offset natural declines from existing well pairs;*
- *Significant incremental or sustained production from the HSEU will not occur until further development drilling and subsea infrastructure comes on-stream, which is expected by 2014;*
- *The continuation of the ramp up of bitumen production from the NSE, and that the NSE will improve productivity of overall mining operations and decrease operating costs by alleviating congestion in the Millennium mining area and reducing average haul distances; and*
- *If regulatory approval is obtained to increase the NSE project area, Suncor's expectation that the expanded area will provide additional recoverable bitumen.*

The anticipated duration and impact of planned maintenance events, including:

- *The event scheduled for the second quarter of 2012 at Oil Sands Base, when the company expects to shut down one coker unit at Upgrader 1;*
- *The event scheduled for the third quarter of 2012 at Oil Sands Base, when the company expects to complete maintenance on the vacuum tower and shut down one coker unit at Upgrader 2;*
- *Suncor's expectations that it will complete maintenance on secondary upgrading units at both Upgrader 1 and Upgrader 2 during 2012;*
- *The 21-week dockside maintenance program planned for Terra Nova in 2012 in the second half of 2012, during which the company plans to replace the FPSO water injection swivel and complete the replacement of subsea infrastructure anticipated to remediate H_2S issues, and that the company expects a return to the field with resumption of production prior to the end of 2012;*
- *The 18-week off-station maintenance program for White Rose that is scheduled to commence during the second quarter of 2012, primarily to address issues with the FPSO propulsion system;*
- *Events scheduled to occur at Hibernia and Buzzard in the third quarter of 2012;*
- *Suncor's expectation that there will be no production from Terra Nova during its dockside maintenance program and no production from White Rose during its off-station maintenance program, and that effective execution of these programs will set the company up for continued success; and*
- *Outages planned for 2012 at the company's refineries, including crude unit maintenance at the Sarnia and Commerce City refineries and minor secondary process unit maintenance at all four refineries.*

Suncor's expectations about where future capital expenditures will be directed, the timing for completion of growth and other significant projects, and the results of such projects, including:

- *The project to reduce benzene content in gasoline production at the Commerce City refinery is expected to be completed by the second quarter of 2012;*
- *Cost estimates and target completion dates provided in the Significant Growth Projects Update table;*

- *Suncor's expectations that it will commission the Firebag Stage 3 cogeneration units in the first quarter of 2012;*
- *Initial bitumen production from the second and third well pads for the Firebag Stage 3 expansion is expected in the first half of 2012, and the ramp up of production from the Firebag Stage 3 expansion is expected to continue throughout 2012 and reach peak production levels during the second half of 2013;*
- *Planned capacity for facilities at each of the Firebag Stage 3 and Stage 4 expansions is 62,500 bbls/d of bitumen and that Stage 4 will add equivalent barrels of production to Stage 3;*
- *Suncor's expectations for the Firebag Stage 4 expansion that in 2012 it will continue construction of well pads, central processing facilities and cogeneration units, and initiate steaming of the first well pad in the fourth quarter of 2012 so that first oil can be achieved late in the first quarter of 2013;*
- *Suncor's expectations that the hydrotreater portion of the MNU will start up in 2012, commissioning of the MNU hydrogen plant will be completed by the middle of 2012, and that the MNU will improve the reliability and availability of Suncor's upgrading facilities;*
- *Suncor's expectations that the Golden Eagle Area Development will include stand-alone facilities designed for 70,000 boe/d of gross production, and that 2012 capital expenditure activity in 2012 will focus on construction and fabrication of topsides and the jacket for the GBS;*
- *The company's plans to construct more tailings drying facilities and expectations that it will complete the TRO_{TM} infrastructure project by the fourth quarter of 2012;*
- *Other capital spending for Oil Sands Base is expected to focus on sustaining capital investments, which maintain production capacities at existing facilities, and include costs for planned maintenance events, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities;*
- *In situ capital spending is expected to focus on continuing to build well pads at Firebag and MacKay River and continuing the infill well program at Firebag;*
- *The company's plan to present to Suncor's Board of Directors for sanctioning the budget for the combined development of the Voyageur upgrader, Fort Hills and Joslyn projects in 2013;*
- *Suncor's expectations that capital spending in 2012 for the Voyageur upgrader project will focus primarily on validating project scope, developing the project execution plan, engineering and progressing site preparation;*
- *Suncor's expectations that capital spending in 2012 for the Fort Hills project will focus primarily on progressing design basis memorandum engineering and site preparation, and procuring long-lead items;*
- *Suncor's expectations that capital spending in 2012 for the Joslyn project will focus on further design work, progressing front-end engineering and site preparation;*
- *Capital expenditures in 2012 for Syncrude will focus on the mine train replacement for the Mildred Lake mine, the mine train relocation at the Aurora mine and sustaining maintenance initiatives;*
- *Suncor's expectations that the second pilot well for water injection support in the White Rose Extensions will be completed in the second quarter of 2012 and that results from the pilot project, along with ongoing evaluations, will help define the scope of future development for the West White Rose field;*
- *The company's expectations for the Hebron project that front-end engineering will be finalized, detailed design will commence and major construction contracts will be awarded, and that it will receive a regulatory approval decision in 2012, followed by a sanction decision by joint venture owners;*
- *For 2012, the company's expectations that it will commence drilling an exploration well for the Romeo joint venture prospect in the U.K. portion of the North Sea and participate in a non-operated exploration well in the Norway portion of the North Sea;*
- *Suncor's expectations that other capital expenditures for East Coast Canada operations will focus on development drilling for Terra Nova, Hibernia and White Rose, the water injection swivel replacement for the FPSO and H_2S remediation activity at Terra Nova, the propulsion system maintenance for the White Rose FPSO, and the procurement of subsea equipment for the development of the HSEU;*
- *The company's expectations that it will commence the drilling of an appraisal well in its Beta discovery in the first quarter of 2012 and that it will participate in an exploration well offshore Norway; and*
- *For North America Onshore operations, the company's plans to continue exploration in the Cardium oil formation and Montney shale gas formation.*

Other elements of Suncor's strategy and operational update for 2012, including:

- *The expectation that Oil Sands operational excellence initiatives will continuously improve plant utilization and workforce productivity;*
- *The company's portfolio of in situ technology projects, which is expected to drive improvements and efficiencies*

in current production and develop future opportunities, and the focus of this portfolio on subsurface and surface challenges;

- *The company's expectations that the development of the Golden Eagle, HSEU, White Rose Extensions and Hebron will be an attractive opportunity to provide low-cost production and generate future cash flow;*
- *That North America Onshore operations will direct attention to cost reduction while pursuing unconventional and liquids-rich plays;*
- *Expectations that Refining and Marketing will continue to focus on the safety and reliability of its operations, leverage the company's strong brand to increase non-petroleum revenues through our network of convenience stores and car washes, and expand the lubricants product offering; and*
- *The Energy Trading business will optimize capacities associated with existing arrangements for pipeline and storage capacity, and optimize existing and future production.*

Also:

- *Suncor's assessment of the situation in Syria, including its determination of the net recoverable value of net assets in Syria that did not indicate than an impairment charge is required at this time, Suncor's expectations about recovering its share of any production during the period of force majeure, if force majeure is lifted, and Suncor's belief that it is entitled to certain receivables;*
- *Suncor's optimism about a gradual return to full operations in Libya and its assessment of the situation in Libya, including the impairment of net assets, the status of physical assets, and sustainability of production rates;*
- *Management's belief that Suncor will have the capital resources to fund its planned 2012 capital spending program of $7.5 billion 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;*
- *Management's belief that 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;*
- *The company plans to maintain access to short-term commercial paper borrowing at competitive interest rates by keeping short-term debt at existing levels;*
- *Steve Williams assuming the role of CEO in May 2012;*
- *The company's expectations that the maximum weighted average term to maturity of its short-term investment portfolio will not exceed six months, and that all investments will be with counterparties with investment grade debt ratings; and*
- *Suncor's assessment of the impact of Bill C-13, which expects that, in future years, the legislation will decrease cash flow from operations by accelerating the payment of cash income taxes, but will not have a significant impact on net earnings.*

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, so readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors.

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate our oil sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance oil sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which 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); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business, such as our *current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.*

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, 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, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and the possibility that operations in Syria continue to be impacted by sanctions or political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; 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; actions by government authorities, including the imposition of taxes or changes to fees and royalties, and changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, 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 that are customary to transactions of this nature; 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 that is needed to reduce the margin of error and increase the level of accuracy; failure to realize anticipated synergies or cost-savings; and incorrect assessments of the values of assets acquired and liabilities assumed in the merger with 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 the MD&A, including under the heading Risk Factors, and the company's 2011 AIF dated March 1, 2012 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission 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 International Financial Reporting Standards as issued by the International Accounting Standards Board. They include certain amounts that are based on estimates and judgments.

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 Audit Committee of the Board of Directors, composed of five 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 reserve evaluators. 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 resources 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
Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 23, 2012

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, 2011, 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, 2011. 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, 2011 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.

Richard L. George
Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 23, 2012

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed an integrated audit of Suncor Energy Inc.'s December 31, 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 and an audit of its December 31, 2010 consolidated financial statements. 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, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and the related notes, which comprise 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 International Financial Reporting Standards as issued by the International Accounting Standards Board 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, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the company's internal control over financial reporting as at December 31, 2011, 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 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 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, 2011, based on criteria established in Internal Control – Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 23, 2012

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	2011	2010
Revenues and Other Income		
Operating revenues, net of royalties (note 7)	**39 337**	32 003
Other income (note 8)	**453**	601
	39 790	32 604
Expenses		
Purchases of crude oil and products	**18 723**	14 831
Operating, selling and general (notes 9 and 27)	**8 424**	7 984
Transportation	**736**	703
Depreciation, depletion, amortization and impairment (note 10)	**3 952**	3 803
Exploration	**116**	218
Loss (gain) on disposal of assets	**136**	(975)
Project start-up costs	**163**	77
Financing expenses (note 11)	**471**	187
	32 721	26 828
Earnings before Income Taxes	**7 069**	5 776
Income Taxes (note 12)		
Current	**1 121**	1 196
Deferred	**1 644**	751
	2 765	1 947
Net Earnings	**4 304**	3 829
Other Comprehensive Income (Loss)		
Foreign currency translation adjustment	**230**	(437)
Foreign currency translation adjustment relating to assets held for sale	**—**	(63)
Foreign currency translation reclassified to net earnings	**14**	49
Cash flow hedges reclassified to net earnings	**—**	(1)
Actuarial loss on employee retirement benefit plans, net of income taxes of $117 (2010 – $49)	**(339)**	(152)
Other Comprehensive Income (Loss)	**(95)**	(604)
Total Comprehensive Income	**4 209**	3 225
Per Common Share (dollars) (note 13)		
Net earnings – basic	**2.74**	2.45
Net earnings – diluted	**2.67**	2.43
Cash dividends	**0.43**	0.40

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Assets			
Current assets			
Cash and cash equivalents (note 14)	**3 803**	1 077	505
Accounts receivable	**5 412**	5 253	3 936
Inventories (note 16)	**4 205**	3 141	2 971
Income taxes receivable	**704**	734	587
Assets held for sale (note 17)	**—**	762	—
Total current assets	**14 124**	10 967	7 999
Property, plant and equipment, net (note 18)	**52 589**	49 958	51 556
Exploration and evaluation (note 19)	**4 554**	3 961	4 342
Other assets (note 20)	**311**	230	259
Goodwill and other intangible assets (note 21)	**3 139**	3 422	3 433
Deferred income taxes (note 12)	**60**	69	210
Total assets	**74 777**	68 607	67 799
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt (note 22)	**763**	1 984	2 317
Current portion of long-term debt (note 22)	**12**	518	25
Accounts payable and accrued liabilities	**7 755**	6 443	5 773
Current portion of provisions (note 25)	**811**	608	882
Income taxes payable	**969**	929	1 274
Liabilities associated with assets held for sale (note 17)	**—**	586	—
Total current liabilities	**10 310**	11 068	10 271
Long-term debt (note 22)	**10 004**	9 829	11 679
Other long-term liabilities (note 23)	**2 392**	2 103	2 073
Provisions (note 25)	**3 752**	2 504	3 305
Deferred income taxes (note 12)	**9 719**	7 911	7 986
Shareholders' equity	**38 600**	35 192	32 485
Total liabilities and shareholders' equity	**74 777**	68 607	67 799

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board of Directors:

Steven W. Williams
Director

Michael W. O'Brien
Director

February 23, 2012

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2011**	2010
Operating Activities		
Net earnings	**4 304**	3 829
Adjustments for:		
Depreciation, depletion, amortization and impairment	**3 952**	3 803
Deferred income taxes	**1 644**	751
Accretion	**157**	235
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)
Change in fair value of derivative contracts	**(40)**	(285)
Loss (gain) on disposal of assets	**136**	(975)
Share-based compensation	**(102)**	113
Exploration	**28**	96
Other	**(516)**	(485)
Decrease (increase) in non-cash working capital (note 15)	**242**	(1 170)
Cash flow provided by operating activities	**9 988**	5 486
Investing Activities		
Capital and exploration expenditures	**(6 850)**	(6 010)
Acquisitions	**(842)**	—
Proceeds from disposal of assets	**3 074**	3 088
Other investments	**(6)**	3
Decrease (increase) in non-cash working capital (note 15)	**26**	(193)
Cash flow used in investing activities	**(4 598)**	(3 112)
Financing Activities		
Net change in short-term debt	**(1 221)**	(333)
Net change in long-term debt	**(4)**	(924)
Repayment of long-term debt	**(500)**	—
Issuance of common shares under share option plans	**213**	81
Purchase of common shares for cancellation (note 26)	**(500)**	—
Dividends paid on common shares	**(664)**	(611)
Cash flow used in financing activities	**(2 676)**	(1 787)
Increase in Cash and Cash Equivalents	**2 714**	587
Effect of foreign exchange on cash and cash equivalents	**12**	(15)
Cash and cash equivalents at beginning of period	**1 077**	505
Cash and Cash Equivalents at End of Period	**3 803**	1 077
Supplementary Cash Flow Information		
Interest paid	**672**	690
Income taxes paid	**885**	1 193

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

($ millions)	Share Capital	Contributed Surplus	Foreign Currency Translation	Cash Flow Hedge	Retained Earnings	Total	Number of Common Shares (thousands)
At January 1, 2010	20 053	536	—	15	11 881	32 485	1 559 778
Net earnings	—	—	—	—	3 829	3 829	—
Foreign currency translation adjustment	—	—	(451)	—	—	(451)	—
Net change in cash flow hedges	—	—	—	(1)	—	(1)	—
Actuarial loss on employee retirement benefit plans	—	—	—	—	(152)	(152)	—
Total comprehensive income (loss)	—	—	(451)	(1)	3 677	3 225	—
Dividends paid on common shares	—	—	—	—	(611)	(611)	—
Issued under share option plans	122	(33)	—	—	—	89	5 292
Issued under dividend reinvestment plan	13	—	—	—	(13)	—	419
Share-based compensation expense	—	4	—	—	—	4	—
At December 31, 2010	20 188	507	(451)	14	14 934	35 192	1 565 489
Net earnings	**—**	**—**	**—**	**—**	**4 304**	**4 304**	**—**
Foreign currency translation adjustment	**—**	**—**	**244**	**—**	**—**	**244**	**—**
Actuarial loss on employee retirement benefit plans	**—**	**—**	**—**	**—**	**(339)**	**(339)**	**—**
Total comprehensive income	**—**	**—**	**244**	**—**	**3 965**	**4 209**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(664)**	**(664)**	**—**
Issued under share option plans	**325**	**(57)**	**—**	**—**	**—**	**268**	**9 920**
Issued under dividend reinvestment plan	**12**	**—**	**—**	**—**	**(12)**	**—**	**355**
Purchase of common shares for cancellation (note 26)	**(222)**	**—**	**—**	**—**	**(278)**	**(500)**	**(17 128)**
Share-based compensation expense	**—**	**94**	**—**	**—**	**—**	**94**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**1**	**—**	**—**	**—**	**1**	**—**
At December 31, 2011	**20 303**	**545**	**(207)**	**14**	**17 945**	**38 600**	**1 558 636**

The accompanying notes are an integral part of the consolidated financial statements.

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

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. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and jointly controlled entities.

The address of the company's registered office is 150 - 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) as issued by the Canadian Institute of Chartered Accountants. In 2010, Canadian GAAP was revised to incorporate International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board. Effective January 1, 2011, the company's consolidated financial statements have been prepared in accordance with IFRS, and IFRS 1 *First-Time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. In previous years, the company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative information has been restated from Previous GAAP to IFRS (see note 6).

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at February 23, 2012, the date the Board of Directors approved the statements.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these financial statements except for the opening IFRS consolidated balance sheet, which has utilized certain exemptions available under IFRS 1 (see note 6).

(c) Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the company's functional currency.

(d) Use of Estimates and Judgment

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgment used in the preparation of the financial statements are described in note 4.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interest in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities. Suncor recognizes its share of assets, liabilities, income and expenses, on a line-by-line basis, of its jointly controlled entities and jointly controlled assets. Investments in entities over which the company has significant influence are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities represent the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in other comprehensive income.

If the company or any of its investments dispose of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net earnings.

(c) 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 properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. 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. Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to exploration and production sharing agreements (EPSAs) are reflected in the consolidated financial statements 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 and Profit Oil are reported as sales revenue. Income tax amounts that the company would pay under the laws of the respective countries are paid by the company's governmental joint venture partners on our behalf, and the company reports these amounts as sales revenues. All other government stakes are considered to be royalty interests.

Physical and financial contracts entered into for trading purposes are considered derivative financial instruments, and any changes in fair value are recorded on a net basis in Other Income.

(d) 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 at the time of purchase.

(e) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. 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 supply and trading operations are carried at fair value less costs to sell, and any changes in fair value are recognized within Other Income.

(f) Exploration and Evaluation Assets

The costs to acquire non-producing oil and gas properties or licence to explore, exploratory well expenditures and the costs to evaluate the commercial potential of underlying resources, including related borrowing costs, are initially capitalized as Exploration and Evaluation assets. Certain exploration costs, including geological, geophysical, seismic, and sampling on oil sands properties, are charged to Exploration expense as incurred.

Exploration and evaluation assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the related capitalized costs are charged to net earnings.

When management determines with reasonable certainty that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is transferred to Property, Plant and Equipment.

(g) Property, Plant and Equipment

Property, plant and equipment are recorded at cost.

The costs to acquire developed or producing oil and gas properties and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install dedicated infrastructure, such as wellhead equipment and supporting assets, mine development, offshore platforms and subsea structures, are capitalized as oil and gas properties within Property, Plant and Equipment.

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, in situ processing facilities, power generation, utility plants, and natural gas processing plants, and all renewable energy, refining, distribution, marketing assets and related decommissioning and restoration obligations, are capitalized as Property, Plant and Equipment. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized.

Stripping activity required to access oil sands mining resources incurred in the initial development phase is capitalized as part of the investment in the construction cost of the mine. Stripping costs incurred in the production phase are charged to expense as they normally relate to production for the period.

The costs of planned major inspection, overhaul and turnaround activities that maintain property, plant and equipment and benefit future years of operations are capitalized. Recurring planned maintenance activities performed on shorter intervals are expensed as operating costs. Replacements outside of a major inspection, overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the company and the associated carrying amount of the replaced asset is derecognized.

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as finance lease assets within Property, Plant and Equipment. Costs for all other leases are recorded as operating expense as incurred.

Borrowing costs relating to assets that take a substantial period of time to construct for their intended use are capitalized as part of Property, Plant and Equipment. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for it to be capable of operating as intended. Capitalization of borrowing costs is suspended when construction of an asset is ceased for extended periods.

(h) Depreciation, Depletion and Amortization

Exploration and evaluation assets are not subject to depreciation, depletion and amortization, with the exception of natural gas leases. Once transferred to Property, Plant and Equipment and commercial production commences, these costs are depleted on a unit-of-production basis over proved developed reserves with the exception of property acquisition costs which are depleted over proved reserves.

Capital expenditures associated with significant development projects are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties, and costs of dedicated infrastructure, such as wellhead equipment, offshore platforms and subsea structures, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves.

Major components of Property, Plant and Equipment are depreciated on a straight-line basis over their expected useful lives.

Natural gas processing plants and transportation assets	15 to 25 years
Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	40 years
Refineries, ethanol and lubricants plants	20 to 40 years
Marketing and other distribution assets	20 to 40 years

The costs of major inspection, overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next scheduled activity, which varies from two to five years.

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

(i) Goodwill and Other Intangible Assets

The company accounts for business combinations using the acquisition method. The excess of the purchase price over the fair value of the identifiable net assets represents goodwill, and is allocated to the cash-generating units (CGUs) or groups of CGUs expected to benefit from the business combination.

Other intangible assets include acquired customer lists and brand value.

Goodwill and brand value have indefinite useful lives and are not subject to amortization. Customer lists are amortized over their expected useful lives, which range from five to 10 years. Expected useful lives of goodwill and other intangible assets are reviewed on an annual basis.

(j) Impairment of Assets

Non-Financial Assets

Intangible assets that have an indefinite useful life are tested annually for impairment. Exploration and evaluation assets are tested for impairment immediately prior to costs being transferred to Property, Plant and Equipment. All other assets are tested for impairment whenever events or changes in circumstance indicate that the carrying amount may not be recoverable.

For the purposes of assessing impairment, assets are grouped into CGUs, defined as the lowest levels for which there are separately identifiable cash inflows. An impairment loss is recognized in Depreciation, Depletion, Amortization and Impairment for the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount. The recoverable amount is the higher of the fair value less costs to sell and value-in-use. In determining fair value less costs to sell, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset or CGU. Exploration and evaluation assets are tested with the producing CGU for which the activity can be attributed or to the segment level it relates to when a producing CGU does not exist for the exploration and evaluation activity.

Impairments are reversed for all CGUs and individual assets, other than goodwill, to the extent that events or circumstances give rise to changes in the estimate of recoverable amount since the period the impairment was recorded. Impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is evidence that a financial asset is impaired. If a financial asset carried at amortized cost is impaired, the amount of the loss is measured as the difference between the amortized cost of the loan or receivable and its recoverable amount. The loss is recognized in Depreciation, Depletion, Amortization and Impairment.

(k) Assets Held For Sale

Assets and liabilities are classified as held for sale if their carrying amounts are expected to be recovered through a disposition rather than through continuing use. The assets or disposal groups are measured at the lower of their carrying amount and fair value less costs to sell. Impairment losses on initial classification as held for sale and subsequent gains or losses on remeasurement are recognized in Loss (Gain) on Disposal of Assets. Assets classified as held for sale are not depreciated, depleted or amortized.

(l) Provisions

Provisions are recognized by the company when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Provisions are recognized for decommissioning and restoration obligations associated with the company's exploration and evaluation assets and property, plant and equipment. Provisions for decommissioning and restoration obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. The provision is accreted over time through charges to Financing Expenses with actual expenditures charged against the accumulated obligation. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes may be recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in earnings or in other comprehensive income in the period they occur. Investment tax credits are recorded as an offset to the related expenditures.

(n) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans, defined contribution pension plans and other post-retirement benefits.

Company contributions to the defined contribution pension plans are expensed as incurred. The cost of the defined benefit pension plans and other post-retirement benefits is actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Costs are recorded in Operating, Selling and General expense. Any actuarial gains or losses are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

The liability recognized on the balance sheet is the present value of the defined benefit obligations less the fair value of plan assets.

(o) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded to Operating, Selling and General expense.

Stock options that give the holder the right to purchase common shares are accounted for as equity-settled plans. The expense is based on the fair value of the options at the time of grant and is recognized over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus. Consideration paid to the company on exercise of options is credited to Share Capital and the associated amount in Contributed Surplus is reclassified to Share Capital.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period and recognized as an expense over the vesting period, with a corresponding adjustment to liabilities. 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 options are recorded to Share Capital.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs (except for financial instruments classified as fair value through profit and loss, where transaction costs are expensed as incurred). Subsequent measurement of financial instruments is based on their classification:

Fair Value through Profit and Loss

Financial assets and liabilities that are held for trading or that are designated as fair value through profit and loss upon initial recognition. Changes in their fair value are recognized in earnings.

Loans and Receivables

Non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Measured at amortized cost using the effective interest method.

Held-to-Maturity

Consists of non-derivative financial assets that the company has the intent and ability to hold until maturity. Measured at amortized cost using the effective interest method.

Other Financial Liabilities

Financial liabilities not classified as fair value through profit and loss. Measured at amortized cost using the effective interest method.

Available for Sale

All other non-derivative financial assets are classified as available for sale, with changes in fair value recognized in other comprehensive income.

The company classifies its derivative financial instruments (except those designated as effective hedging instruments) as fair value through profit and loss, its cash and cash equivalents and accounts receivable as loans and receivables, its financial instruments included in other assets as available for sale, and its accounts payable and accrued liabilities, debt, and other long-term liabilities as other financial liabilities.

The company uses derivative financial instruments either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program, or to earn trading revenues. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related operating segment. Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations.

Certain physical commodity contracts are deemed to be derivative financial instruments for accounting purposes. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract.

(q) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. 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.

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 item attributable to the hedged risk are recognized in 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 earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings immediately. Changes in the fair value of a derivative designated in a fair value or cash flow hedge are recognized in the same line item as the underlying hedged item.

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(s) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are approved by the company's Board of Directors.

(t) Earnings per Share

Basic earnings per share is calculated by dividing the net earnings for the period by the weighted-average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted-average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. For share-based compensation plans that may be settled in ordinary shares or cash at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

Oil and Gas Reserves and Resources

Certain depletion, depreciation, impairment and decommissioning and restoration charges are measured based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2011 by independent petroleum consultants in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2011, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make estimates and judgment about future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Unsuccessful drilling, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important factors when making this determination. If a judgment is made that the extraction of resources is not viable, the associated exploration and evaluation costs are impaired and charged to net earnings.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of exploration and evaluation assets and property, plant and equipment. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

Pensions and Other Post-Retirement Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is determined based on actuarial valuation methods and assumptions. Changes to assumptions related to discount rates, expected return on plan assets and annual rates of compensation increases may have a material impact on the amounts presented.

Impairment of Assets

A cash-generating unit (CGU) is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, future operating and development costs, and refining margins. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Derivative Financial Instruments

When not directly observable in active markets, the company uses third-party models and valuation methodologies that utilize observable market data to estimate the fair value of derivative financial instruments. 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.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for all fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant changes to its fair value measurements and related disclosures as a result of this standard.

Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statement*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and special purpose vehicles. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including joint arrangements, associates and special purpose vehicles.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted. The company is currently assessing the impact of these standards.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits,* which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in other comprehensive income, eliminating the previous options that were available, and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant impacts as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization and depreciation of stripping costs in the production phase if an entity can demonstrate that it is probable that future economic benefits will be realized, the costs can be reliably measured and the entity can identify the component of the ore body for which access has been improved. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The company does not anticipate significant impacts as a result of this interpretation.

6. FIRST-TIME ADOPTION OF IFRS

Effective January 1, 2011, the company began reporting under IFRS, and the accounting policies disclosed in note 3 to these consolidated financial statements have been applied in preparing the financial statements for the years ended December 31, 2011 and 2010 and in the preparation of the company's opening balance sheet at January 1, 2010 (Transition Date).

In previous years, the company prepared its consolidated financial statements in accordance with Previous GAAP. Reconciliations from Previous GAAP to IFRS for comparative periods are provided on the following pages.

Reconciliation of Equity at December 31, 2010

($ millions)	Previous GAAP (1)	Presentation Changes for Discontinued Operations (2)	Other Presentation Changes (3)	IFRS Adjustments (4)	IFRS
Assets					
Current assets					
Cash and cash equivalents	1 077	—	—	—	1 077
Accounts receivable	5 253	—	—	—	5 253
Inventories	3 141	—	—	—	3 141
Income taxes receivable	734	—	—	—	734
Deferred income taxes	210	—	(210)	—	—
Assets held for sale (5)	98	658	—	6	762
Total current assets	10 513	658	(210)	6	10 967
Property, plant and equipment, net (5)(6)(7)(8)(9)(10)(14)	55 290	—	(3 961)	(1 371)	49 958
Exploration and evaluation	—	—	3 961	—	3 961
Other assets	451	—	(221)	—	230
Goodwill	3 201	—	(3 201)	—	—
Goodwill and other intangible assets	—	—	3 422	—	3 422
Deferred income taxes	56	—	13	—	69
Assets of discontinued operations	658	(658)	—	—	—
Total assets	70 169	—	(197)	(1 365)	68 607
Liabilities and Shareholders' Equity					
Current liabilities					
Short-term debt	2	—	1 982	—	1 984
Current portion of long-term debt	518	—	—	—	518
Accounts payable and accrued liabilities (11)(12)	6 942	—	(604)	105	6 443
Current portion of provisions	—	—	604	4	608
Income taxes payable	929	—	—	—	929
Deferred income taxes	37	—	(37)	—	—
Liabilities associated with assets held for sale (5)(6)(14)	98	484	—	4	586
Total current liabilities	8 526	484	1 945	113	11 068
Long-term debt (7)	11 669	—	(1 982)	142	9 829
Accrued liabilities and other	4 154	—	(4 154)	—	—
Other long-term liabilities (11)(12)	—	—	1 861	242	2 103
Provisions (5)(6)	—	—	2 293	211	2 504
Deferred income taxes (14)	8 615	—	(160)	(544)	7 911
Liabilities of discontinued operations	484	(484)	—	—	—
Shareholders' equity (5)(6)(7)(8)(9)(10)(11)(12)(13)(14)	36 721	—	—	(1 529)	35 192
Total liabilities and shareholders' equity	70 169	—	(197)	(1 365)	68 607

See footnotes starting on page 98.

Reconciliation of Equity at January 1, 2010

($ millions)	Previous GAAP[1]	Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Assets				
Current assets				
Cash and cash equivalents	505	—	—	505
Accounts receivable	3 936	—	—	3 936
Inventories	2 971	—	—	2 971
Income taxes receivable	587	—	—	587
Deferred income taxes	332	(332)	—	—
Total current assets	8 331	(332)	—	7 999
Property, plant and equipment, net[5][7][8][9][14]	57 485	(4 297)	(1 632)	51 556
Exploration and evaluation	—	4 342	—	4 342
Other assets	536	(277)	—	259
Goodwill	3 201	(3 201)	—	—
Goodwill and other intangible assets	—	3 433	—	3 433
Deferred income taxes	193	17	—	210
Total assets	69 746	(315)	(1 632)	67 799
Liabilities and Shareholders' Equity				
Current liabilities				
Short-term debt	2	2 315	—	2 317
Current portion of long-term debt	25	—	—	25
Accounts payable and accrued liabilities[11][12]	6 529	(882)	126	5 773
Current portion of provisions	—	882	—	882
Income taxes payable	1 274	—	—	1 274
Deferred income taxes	18	(18)	—	—
Total current liabilities	7 848	2 297	126	10 271
Long-term debt[7]	13 855	(2 315)	139	11 679
Accrued liabilities and other	5 062	(5 062)	—	—
Other long-term liabilities[11][12]	—	2 053	20	2 073
Provisions[5]	—	3 009	296	3 305
Deferred income taxes[14]	8 870	(297)	(587)	7 986
Shareholders' equity[5][7][8][9][11][12][13][14]	34 111	—	(1 626)	32 485
Total liabilities and shareholders' equity	69 746	(315)	(1 632)	67 799

See footnotes starting on page 98.

Reconciliation of Comprehensive Income for the Year Ended December 31, 2010

($ millions)	Previous GAAP (1)	Presentation Changes for Discontinued Operations (2)	Other Presentation Changes (3)	IFRS Adjustments (4)	IFRS
Revenues and Other Income					
Operating revenues	33 198	911	(2 106)	—	32 003
Less: Royalties	(1 937)	(41)	1 978	—	—
Operating revenues, net of royalties	31 261	870	(128)	—	32 003
Other income	491	—	110	—	601
	31 752	870	(18)	—	32 604
Expenses					
Purchases of crude oil and products	14 911	(62)	(18)	—	14 831
Operating, selling and general (7)(11)(12)	7 810	185	—	(11)	7 984
Transportation	656	47	—	—	703
Depreciation, depletion, amortization and impairment (5)(7)(8)(9)(10)	3 813	264	—	(274)	3 803
Accretion of asset retirement obligations	178	27	(205)	—	—
Exploration	197	21	—	—	218
Gain on disposal of assets (6)	(107)	(814)	—	(54)	(975)
Project start-up costs	77	—	—	—	77
Financing expenses (income) (5)(7)	(30)	18	205	(6)	187
	27 505	(314)	(18)	(345)	26 828
Earnings before Income Taxes	4 247	1 184	—	345	5 776
Income Taxes					
Current	1 004	192	—	—	1 196
Deferred (14)	555	109	—	87	751
	1 559	301	—	87	1 947
Net Earnings from Continuing Operations	2 688	883	—	258	3 829
Net Earnings from Discontinued Operations	883	(883)	—	—	—
Net Earnings	3 571	—	—	258	3 829
Other Comprehensive Income (Loss)					
Foreign currency translation adjustment (5)(11)	(503)	—	63	3	(437)
Foreign currency translation adjustment relating to assets held for sale	—	—	(63)	—	(63)
Foreign currency translation reclassified to net earnings (6)	53	—	—	(4)	49
Cash flow hedges reclassified to net earnings	(1)	—	—	—	(1)
Actuarial loss on employee retirement benefit plans (11)(14)	—	—	—	(152)	(152)
Other Comprehensive Loss	(451)	—	—	(153)	(604)
Total Comprehensive Income	3 120	—	—	105	3 225

See footnotes starting on page 98.

Explanation of Significant Adjustments

(1) Represents amounts reported under Previous GAAP. Previous GAAP balances as at January 1, 2010 agree to December 31, 2009 balances reported in the company's 2009 Annual Report.

Energy Supply and Trading Activities Income and Expenses have been reclassified to conform to net basis presentation adopted in the second quarter of 2011, with net amounts now recorded in Other Income (see note 8).

(2) Certain assets held for sale reported as discontinued operations under Previous GAAP are not classified as such under IFRS.

(3) Represents other presentation changes to comply with IFRS. A description of significant reclassifications is as follows:

- Exploration and Evaluation assets reported within Property, Plant and Equipment under Previous GAAP are reflected as a separate line under IFRS.
- Short-term debt instruments supported by a revolving credit facility with a separate lender are classified as Short-Term Debt under IFRS. These short-term debt instruments were classified as Long-Term Debt under Previous GAAP.
- Liabilities encompassing significant uncertainty in timing or amount are reported as Provisions under IFRS. Under Previous GAAP, these liabilities were classified within Accounts Payable and Accrued Liabilities, and Accrued Liabilities and Other.

There were no presentation changes made to the Consolidated Statements of Cash Flows.

(4) Represents the impact on financial statements of transition to IFRS from Previous GAAP, except for presentation changes. The significant adjustments are described below, with the resulting impacts on income taxes described in paragraph (14).

(5) *Decommissioning and Restoration*

Under Previous GAAP, increases in the estimated cash flows were discounted using the current credit-adjusted risk-free rate, while downward revisions in the estimated cash flows were discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. Under IFRS, estimated cash flows are discounted using the credit-adjusted risk-free rate that exists at the balance sheet date.

In accordance with IFRS 1, the company elected to remeasure its decommissioning and restoration costs at the Transition Date and has estimated the related asset by discounting the liability to the date in which the liability arose and recalculated the accumulated depreciation, depletion and amortization under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Assets held for sale	6	—
Property, plant and equipment, net	(688)	(690)
Liabilities associated with assets held for sale	27	—
Provisions	217	296
Foreign currency translation	1	—
Retained earnings	(927)	(986)
Depreciation, depletion, amortization and impairment	(40)	—
Financing expenses (income)	(19)	—
Foreign currency translation adjustment	1	—

(6) *Dispositions*

The net carrying values of disposed properties have been adjusted to reflect their respective IFRS adjustments, resulting in revised gains or losses upon disposal of the assets. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	22	—
Liabilities associated with assets held for sale	(18)	—
Provisions	(10)	—
Foreign currency translation	(4)	—
Retained earnings	54	—
Gain on disposal of assets	(54)	—
Foreign currency translation reclassified to net earnings	(4)	—

(7) *Leases*

In accordance with IFRS 1, the company elected to evaluate whether certain arrangements contain a lease based on the facts and circumstances existing at Transition Date. Pursuant to such evaluation, the company has accounted for certain arrangements as finance leases under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	101	103
Long-term debt	142	139
Retained earnings	(41)	(36)
Operating, selling and general	(13)	—
Depreciation, depletion, amortization and impairment	5	—
Financing expenses (income)	13	—

(8) *Derecognition of Assets*

Under Previous GAAP, carrying amounts of property, plant and equipment assets were derecognized when no future economic benefits were expected from their use. Under IFRS, this derecognition of assets occurs at the component level. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(141)	(113)
Retained earnings	(141)	(113)
Depreciation, depletion, amortization and impairment	28	—

(9) *Fair Value as Deemed Cost*

The company has applied the IFRS 1 election to record certain assets of property, plant and equipment at fair value on the Transition Date. The exemption has been applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada. When estimating fair value, market information for similar assets was used, and where market information was not available, management relied on internally generated cash flow models using discount rates specific to the asset and long-term forecasts of commodity prices and refining margins. The aggregate of these fair values was $1.370 billion, resulting in a reduction of the carrying amount of property, plant and equipment as at January 1, 2010. Under Previous GAAP, impairment losses were recorded in the third quarter of 2010 for certain of these natural gas properties. There were no impairment losses recognized during 2010 under IFRS, as these properties were adjusted to fair value at the Transition Date. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(527)	(906)
Retained earnings	(527)	(906)
Depreciation, depletion, amortization and impairment	(379)	—

(10) *Impairment of Assets*

Under Previous GAAP, an item of property, plant and equipment is deemed recoverable if the undiscounted future cash flows exceed the net carrying amount of the asset group. Under IFRS, recoverability of property, plant and equipment is based on the higher of fair value less costs to sell and value in use of the CGU.

Under IFRS, the company recognized impairment losses for certain CGUs within the Exploration and Production operating segment during 2010. The impaired natural gas assets are located within the Western Canadian Sedimentary Basin and were grouped into CGUs based on similar geological structure, shared infrastructure and similar exposure to market risks. Declining long-term natural gas prices have resulted in the carrying amounts for these CGUs exceeding their recoverable amounts. Recoverable amounts have been determined using the fair value less costs to sell method and based on internally generated cash flow projections. In determining fair value less costs to sell, the company considered recent transactions within the industry, long-term views of natural gas prices, externally evaluated reserve volumes, and discount rates specific to the asset. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(112)	—
Retained earnings	(112)	—
Depreciation, depletion, amortization and impairment	112	—

(11) *Employee Benefits*

Under Previous GAAP, unamortized actuarial gains and losses in respect of the company's defined benefit pension plans were recognized into earnings over the expected average remaining service life of employees. In accordance with IFRS 1, the company has elected to recognize all cumulative actuarial gains and losses directly in Retained Earnings at the Transition Date. Under IFRS, actuarial gains and losses incurred in the period are recorded in Other Comprehensive Income and then transferred directly to Retained Earnings.

Under Previous GAAP, the expense recognition period for other post-retirement benefit plans began on the employee's date of hire. Under IFRS, this period now commences when the employee reaches 45 years of age, the point at which the employee first starts accruing benefits under these plans.

The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	10	15
Other long-term liabilities	215	15
Foreign currency translation	2	—
Retained earnings	(227)	(30)
Operating, selling and general	(4)	—
Foreign currency translation adjustment	2	—
Actuarial loss on employee retirement benefit plans	(201)	—

(12) *Share-Based Compensation*

Under Previous GAAP, the company recorded obligations for cash-settled share-based compensation plans using the intrinsic value method. Under IFRS, obligations for these same plans are recorded as a liability using the fair value method. For equity-settled share-based compensations plans, the company accrues the cost of employee stock options over the vesting period using the graded method of amortization rather than the straight-line method, which the company used under Previous GAAP. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	95	111
Other long-term liabilities	27	5
Contributed surplus	2	10
Retained earnings	(124)	(126)
Operating, selling and general	(2)	—

(13) *Foreign Exchange*

In accordance with IFRS 1, the company elected at the Transition Date to transfer all foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date to Retained Earnings. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Foreign currency translation	248	248
Retained earnings	(248)	(248)

(14) *Income Taxes*

The company recognized deferred income taxes primarily in respect of the above changes. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(26)	(26)
Liabilities associated with assets held for sale	(5)	—
Deferred income taxes – liability	(544)	(587)
Retained earnings	523	561
Deferred income taxes – expense	87	—
Actuarial loss on employee retirement benefit plans	49	—

(15) *Earnings per Common Share*

Under Previous GAAP, the dilutive impact of options with tandem stock appreciation rights or cash payment alternatives was not included in the calculation of diluted earnings per share. Under IFRS, these awards are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period.

The impact on the net earnings amount used in the calculation of diluted earnings per share for the year ended December 31, 2010 can be seen in note 13.

(16) In addition to the IFRS 1 elections described in this note, the company has also applied the following elections:

- Business combinations and acquisitions of interests in associates and joint ventures that occurred prior to the Transition Date were not restated in accordance with IFRS. An impairment test of associated goodwill was performed as at the Transition Date and no impairment losses were identified.
- Borrowing costs capitalized for qualifying projects prior to the Transition Date were not restated for the specific measurement rules required by IFRS.

7. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services. The following summary describes the operations in each of the segments:

- Oil Sands includes the company's 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. This segment also includes the company's 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.
- Exploration and Production includes exploration and production of natural gas, crude oil and natural gas liquids in Western Canada, offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the 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 United States (U.S.), as well as a lubricants plant located in Eastern Canada.

The company also reports activities not directly attributable to an operating segment under Corporate, Energy Trading and Eliminations. This includes investments in renewable energy projects, and results relating to energy trading activities.

In the first quarter of 2011, the company combined its International and Offshore and Natural Gas segments into one new segment, Exploration and Production. All prior periods have been reclassified to conform to these segment definitions.

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment amounts are eliminated on consolidation. The company has one customer that individually represents 11% of the consolidated revenues for the year ended December 31, 2011. No other customers represent more than 10% of the consolidated revenues for the year ended December 31, 2011 (2010 – nil).

	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
For the years ended December 31 ($ millions)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Revenues and Other Income										
Gross revenues	**9 581**	7 052	**6 293**	6 326	**25 657**	20 653	**77**	30	**41 608**	34 061
Intersegment revenues	**3 420**	2 638	**491**	717	**56**	207	**(3 967)**	(3 562)	**—**	—
Less: Royalties	**(799)**	(681)	**(1 472)**	(1 377)	**—**	—	**—**	—	**(2 271)**	(2 058)
Operating revenues, net of royalties	**12 202**	9 009	**5 312**	5 666	**25 713**	20 860	**(3 890)**	(3 532)	**39 337**	32 003
Other income	**31**	415	**(3)**	261	**58**	21	**367**	(96)	**453**	601
	12 233	9 424	**5 309**	5 927	**25 771**	20 881	**(3 523)**	(3 628)	**39 790**	32 604
Expenses										
Purchases of crude oil and products	**1 381**	1 070	**585**	240	**20 547**	16 920	**(3 790)**	(3 399)	**18 723**	14 831
Operating, selling and general	**5 169**	4 537	**850**	933	**2 182**	2 200	**223**	314	**8 424**	7 984
Transportation	**399**	291	**116**	230	**219**	200	**2**	(18)	**736**	703
Depreciation, depletion, amortization and impairment	**1 374**	1 310	**2 035**	1 978	**444**	440	**99**	75	**3 952**	3 803
Exploration	**56**	6	**60**	212	**—**	—	**—**	—	**116**	218
Loss (gain) on disposal of assets	**122**	14	**31**	(998)	**(16)**	(30)	**(1)**	39	**136**	(975)
Project start-up costs	**163**	74	**—**	3	**—**	—	**—**	—	**163**	77
Financing expenses (income)	**74**	104	**65**	78	**13**	11	**319**	(6)	**471**	187
	8 738	7 406	**3 742**	2 676	**23 389**	19 741	**(3 148)**	(2 995)	**32 721**	26 828
Earnings (Loss) before Income Taxes	**3 495**	2 018	**1 567**	3 251	**2 382**	1 140	**(375)**	(633)	**7 069**	5 776
Income taxes	**892**	498	**1 261**	1 313	**656**	321	**(44)**	(185)	**2 765**	1 947
Net Earnings (Loss)	**2 603**	1 520	**306**	1 938	**1 726**	819	**(331)**	(448)	**4 304**	3 829
Capital and Exploration Expenditures	**5 100**	3 709	**874**	1 274	**633**	667	**243**	360	**6 850**	6 010

Total Assets ($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Oil Sands	**44 217**	39 382	36 657
Exploration and Production	**14 290**	15 899	19 218
Refining and Marketing	**13 150**	11 292	9 748
Corporate, Energy Trading and Eliminations	**3 120**	2 034	2 176
	74 777	68 607	67 799

Geographical Information

Operating Revenues, net of Royalties ($ millions)	**2011**	2010
Canada	**31 876**	24 053
Foreign	**7 461**	7 950
	39 337	32 003

Non-Current Assets [1] ($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Canada	**53 794**	50 033	50 348
Foreign	**6 799**	7 538	9 234
	60 593	57 571	59 582

(1) Excludes deferred income tax assets.

8. OTHER INCOME

Other Income consists of the following:

($ millions)	**2011**	2010
Risk management activities	**(22)**	89
Energy trading activities [1]		
Change in fair value of contracts	**301**	106
Unrealized losses on inventory valuation	**(19)**	(4)
Investment and interest income	**141**	44
Renewable energy grants	**64**	36
Other	**(12)**	35
Terra Nova redetermination [2]	**—**	295
	453	601

(1) In the second quarter of 2011, the company completed a review of its energy supply and trading activities. It was determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities income and expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Realized and unrealized gains and losses, and the underlying settlement of these contracts, is now recognized and recorded on a net basis.

Prior period comparative figures have been reclassified for comparability with the current period presentation. The impact is as follows:

($ millions, increase/(decrease))	Year ended December 31, 2010
Energy supply and trading activities income	(2 700)
Other income	102
Energy supply and trading activities expenses	(2 598)
Net earnings	—

(2) In 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests 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 agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company recognized income of $295 million in 2010.

9. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	**2011**	2010
Contract services	**4 107**	3 997
Employee benefits [1]	**2 062**	2 149
Materials	**882**	1 175
Energy	**712**	546
Other	**661**	117
	8 424	7 984

(1) The company incurred $2.5 billion of employee benefits costs for the year ended December 31, 2011 (2010 – $2.4 billion), of which $2.1 billion (2010 – $2.1 billion) was recorded as employee benefits expense in Operating, Selling and General expense. Employee benefits expense includes salaries, benefits and share-based compensation.

10. ASSET IMPAIRMENT

Libya

In the second quarter of 2011, the company recognized impairment losses of $514 million related to Libyan assets in its Exploration and Production business. At that time, production had been shut-in due to political violence in Libya.

In calculating the company's impairment in the second quarter of 2011, the recoverable amount was determined using a value-in-use methodology. The company used an expected cash flow approach based on 2010 year-end reserves data updated for current price forecasts, with three scenarios representing i) resumption of normal operations after one year, ii) resumption of normal operations after two years, and iii) total loss. These scenarios were probability-weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 17%. The two scenarios where the company resumes production incorporated rebuilding costs.

The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense in the Consolidated Statements of Comprehensive Income, and charged against Property, Plant and Equipment ($259 million), Exploration and Evaluation assets ($211 million), and Inventories ($44 million) in the Consolidated Balance Sheets.

During the third quarter of 2011, a change in the Libyan government resulted in the lifting of certain sanctions that were impacting the company's operations in the country. In the fourth quarter of 2011, the company's joint venture partner restarted production in certain fields, and in January 2012 the company started to receive production payments. In addition, the joint venture partner confirmed the existence of crude oil written off in the second quarter of 2011, and the company reversed the $11 million impairment charge that related to crude oil inventories.

Discussions with the Libyan authorities have commenced on the status of existing contract terms, including production volumes and time frames for future exploration commitments. However, there is unpredictability around current production levels and ramp-up expectations, and the extent of the damage to the company's assets has not yet been fully assessed. Therefore, at December 31, 2011, there has been no change in the company's overall assessment of the impairment, and no reversal of impairment has been recognized except for the $11 million crude oil inventories.

Syria

In December 2011, the company suspended its operations with the Syrian General Petroleum Company and ceased recording production or revenues. These actions were taken as a result of sanctions announced by the European Union on December 2, 2011.

An impairment test was performed on the company's Syrian assets, which determined that the assets were not impaired at December 31, 2011. The recoverable amount was determined using the value-in-use methodology. The company used an expected cash flow approach based on current price forecasts and 2011 year-end reserves data, which take into account the long-term nature of natural gas reserves associated with these assets. The company used four scenarios representing i) resumption of normal operations after six months, ii) resumption of normal operations after one year, iii) resumption of normal operations after two years, and iv) total loss. These scenarios were probability-weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 17%. The three scenarios where the company resumes normal operations assume that upon return the company will receive payment for any production during its absence.

The calculation of value-in-use is most sensitive to management's assumption on the timing of resumption of normal operations. If the probability weighting in the cash flow model was adjusted to reflect no probability of the company resuming normal operations within the next twelve months, the company's Syrian assets may be impaired.

The carrying value of the company's net assets in Syria at December 31, 2011 was approximately $900 million.

Other

During the fourth quarter of 2011, the company recognized a write-down of $100 million related to certain natural gas CGUs in the Exploration and Production business due to a decrease in price forecasts. The recoverable amount was determined using a fair value less costs to sell methodology, with the expected future cash flows based on 2011 year-end reserves data with third-party price forecasts and a discount rate of 12%.

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. Also during the second quarter of 2010, the company recognized a write-down of $44 million of certain land leases in the Exploration and Production 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 write-down of $106 million related to certain North Sea assets in the Exploration and Production 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 the fourth quarter of 2010, the company recognized a charge of $112 million to reflect the write-down of certain assets in the Exploration and Production operating segment to reflect fair value based on discounted future cash flows.

These charges are included in Depreciation, Depletion, Amortization and Impairment expense in the Consolidated Statements of Comprehensive Income.

11. FINANCING EXPENSES

($ millions)	2011	2010
Interest on debt	**661**	704
Capitalized interest at 6.0% (2010 – 5.4%)	**(559)**	(301)
Interest expense	**102**	403
Accretion	**157**	235
Foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)
Other foreign exchange loss (gain)	**29**	(25)
Total financing expenses	**471**	187

12. INCOME TAXES

Income Tax Expense

($ millions)	2011	2010
Current:		
Current year	**1 103**	1 172
Adjustments for prior years	**18**	24
Deferred:		
Origination and reversal of temporary differences	**1 258**	770
Adjustments for prior years	**(56)**	(4)
Changes in tax rates and legislation	**442**	(15)
	2 765	1 947

Tax Recognized in Other Comprehensive Income

($ millions)	2011	2010
Employee retirement benefit plans	**(117)**	(49)
	(117)	(49)

There was no income tax recognized directly in equity during 2010 and 2011.

Reconciliation of Effective Tax Rate

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the difference is as follows:

($ millions)	2011	2010
Earnings before income tax	**7 069**	5 776
Canadian statutory tax rate	**27.19%**	28.91%
Statutory tax	**1 922**	1 670
Add (deduct) the tax effect of:		
Non-taxable component of capital gains and losses	**(33)**	(67)
Share-based compensation and other permanent items	**34**	1
Assessments and adjustments	**(38)**	20
Impact of income tax rate and legislative changes[1]	**442**	(15)
Canadian tax rate differential	**(116)**	(106)
Foreign tax rate differential	**383**	440
Non-taxable Libyan impairment charge	**142**	—
Other	**29**	4
	2 765	1 947

(1) In March 2011, the U.K. government substantively enacted a 12% increase in the supplementary charge on U.K. oil and gas profits. Accordingly, in the first quarter of 2011, the company recognized an increase in deferred tax expense of $442 million related to the revaluation of deferred income tax balances.

Deferred Income Tax Balances

Deferred income tax expense and net liabilities in the company's financial statements were comprised of the following:

	Consolidated Statements of Comprehensive Income		Consolidated Balance Sheets [1]		
($ millions)	**2011**	2010	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Property, plant and equipment	**967**	612	**10 725**	9 453	9 236
Risk management and energy trading	**—**	27	**9**	27	—
Decommissioning and restoration provision	**205**	178	**(507)**	(713)	(891)
Employee retirement benefit plans	**73**	(50)	**(518)**	(492)	(393)
Tax loss carry-forwards	**(213)**	(251)	**(558)**	(372)	—
Partnership deferral reserve	**594**	—	**594**	121	—
Other	**18**	235	**(86)**	(182)	(176)
	1 644	751	**9 659**	7 842	7 776

(1) The deferred income tax liability of $9.719 billion at December 31, 2011 (December 31, 2010 – $7.911 billion, January 1, 2010 – $7.986 billion) includes $9.713 billion (December 31, 2010 – $7.911 billion, January 1, 2010 – $7.724 billion) that will be settled beyond the next twelve months.

The deferred income tax asset of $60 million at December 31, 2011 (December 31, 2010 – $69 million, January 1, 2010 – $210 million) includes $47 million (December 31, 2010 – $51 million, January 1, 2010 – $94 million) that will be recovered beyond the next twelve months.

Change in Deferred Income Tax Balances

($ millions)	**2011**	2010
Beginning of year	**7 842**	7 776
Recognized in deferred income tax expense	**1 644**	751
Recognized in other comprehensive income	**(117)**	(49)
Other	**290**	(636)
End of year	**9 659**	7 842

No deferred tax liability has been recognized at December 31, 2011 on temporary differences of approximately $9 billion (2010 – $8 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

13. EARNINGS PER COMMON SHARE

($ millions)	**2011**	2010
Net earnings	**4 304**	3 829
Dilutive impact of accounting for awards as equity-settled [1]	**(86)**	(6)
Net earnings – diluted	**4 218**	3 823
(millions of common shares)		
Weighted-average number of common shares	**1 571**	1 562
Dilutive securities:		
Effect of share options	**11**	14
Weighted-average number of diluted common shares	**1 582**	1 576
(dollars per common share)		
Basic earnings per share	**2.74**	2.45
Diluted earnings per share	**2.67**	2.43

(1) Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have the most dilutive impact for the years ended December 31, 2011 and 2010.

14. CASH AND CASH EQUIVALENTS

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Cash	**832**	358	205
Cash equivalents	**2 971**	719	300
	3 803	1 077	505

15. SUPPLEMENTAL CASH FLOW INFORMATION

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

($ millions)	**2011**	2010
Accounts receivable	**(263)**	(568)
Inventories	**(1 064)**	(190)
Accounts payable and accrued liabilities	**1 322**	130
Provisions	**203**	(274)
Income taxes payable/receivable	**70**	(461)
Total	**268**	(1 363)
Relating to:		
Operating activities	**242**	(1 170)
Investing activities	**26**	(193)

16. INVENTORIES

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Crude oil	**1 321**	916	781
Refined products	**1 741**	1 289	1 303
Materials, supplies and merchandise	**592**	564	532
Energy trading commodity inventories	**551**	372	355
Total [1]	**4 205**	3 141	2 971

(1) At December 31, 2010, inventories of $11 million were reclassified to assets held for sale.

During 2011, product inventories of $18.7 billion (2010 – $14.8 billion) were expensed. There was a write-down of inventories of $33 million in 2011 – see note 10 (2010 – $nil).

17. ASSETS HELD FOR SALE

In the first quarter of 2011, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £90 million (Cdn$140 million). In the second and third quarters of 2011, the company completed the sale of certain non-core assets located in northern Alberta and northeast British Columbia for net proceeds of $164 million. The company recognized a loss of $31 million on these disposals in 2011.

During 2010, the company completed the sale of a number of non-core North American oil and gas properties for net proceeds of approximately $1.7 billion. The company also completed the disposition of certain international operations, including its shares in Petro-Canada Netherlands BV, assets in Trinidad and Tobago, and certain U.K. offshore assets, for net proceeds of approximately $900 million. The company recognized a gain of $868 million on these disposals in 2010.

The company had no assets or liabilities classified as assets held for sale at December 31, 2011 or January 1, 2010. The assets and liabilities classified as held for sale at December 31, 2010 were as follows:

($ millions)	**Dec 31 2010**
Assets	
Current assets	98
Property, plant and equipment, net	635
Exploration and evaluation	29
	762
Liabilities	
Current liabilities	98
Provisions	311
Deferred income taxes	177
	586

18. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	**Total**
Cost			
At January 1, 2010	19 947	39 179	59 126
Additions	1 363	4 356	5 719
Transfers from exploration and evaluation	3	—	3
Changes in decommissioning and restoration	(67)	18	(49)
Disposals	(2 947)	(739)	(3 686)
Transfers to assets held for sale	(711)	—	(711)
Foreign exchange adjustments	(607)	(97)	(704)
At December 31, 2010	16 981	42 717	59 698
Additions	**1 358**	**4 952**	**6 310**
Transfers from exploration and evaluation	**237**	**—**	**237**
Acquisitions (note 33)	**—**	**126**	**126**
Changes in decommissioning and restoration	**1 862**	**15**	**1 877**
Disposals	**(405)**	**(2 717)**	**(3 122)**
Foreign exchange adjustments	**256**	**50**	**306**
At December 31, 2011	**20 289**	**45 143**	**65 432**
Accumulated provision			
At January 1, 2010	(2 076)	(5 494)	(7 570)
Depreciation and depletion	(1 647)	(1 441)	(3 088)
Impairment	(218)	—	(218)
Disposals	795	208	1 003
Transfers to assets held for sale	76	—	76
Foreign exchange adjustments	42	15	57
At December 31, 2010	(3 028)	(6 712)	(9 740)
Depreciation and depletion	**(1 622)**	**(1 770)**	**(3 392)**
Impairment	**(359)**	**—**	**(359)**
Disposals	**316**	**356**	**672**
Foreign exchange adjustments	**(13)**	**(11)**	**(24)**
At December 31, 2011	**(4 706)**	**(8 137)**	**(12 843)**
Net property, plant and equipment			
January 1, 2010	17 871	33 685	51 556
December 31, 2010	13 953	36 005	49 958
December 31, 2011	**15 583**	**37 006**	**52 589**

($ millions)	Dec 31, 2011 Cost	Accumulated provision	Net property, plant and equipment	Dec 31, 2010 Cost	Accumulated provision	Net property, plant and equipment
Oil Sands	**41 679**	**(6 548)**	**35 131**	37 485	(5 206)	32 279
Exploration and Production	**13 757**	**(4 018)**	**9 739**	12 822	(2 522)	10 300
Refining and Marketing	**8 834**	**(1 953)**	**6 881**	8 491	(1 776)	6 715
Corporate, Energy Trading and Eliminations	**1 162**	**(324)**	**838**	900	(236)	664
	65 432	**(12 843)**	**52 589**	59 698	(9 740)	49 958

At December 31, 2011, the balance of assets under construction, and not subject to depreciation or depletion, was $16.2 billion (December 31, 2010 – $15.9 billion, January 1, 2010 – $15.1 billion).

At December 31, 2011, property, plant and equipment included finance leases with a net book value of $425 million (December 31, 2010 – $403 million, January 1, 2010 – $376 million).

19. EXPLORATION AND EVALUATION ASSETS

($ millions)	**2011**	2010
Beginning of year	**3 961**	4 342
Acquisitions	**716**	—
Additions	**657**	275
Transfers to oil and gas assets	**(237)**	(3)
Dry hole expenses	**(21)**	(45)
Disposals	**(263)**	(342)
Impairment (note 10)	**(211)**	(44)
Amortization	**(44)**	(54)
Transfers to assets held for sale	**—**	(29)
Foreign exchange adjustments	**(4)**	(139)
End of year	**4 554**	3 961

20. OTHER ASSETS

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Investments	**228**	135	148
Other	**83**	95	111
	311	230	259

21. GOODWILL AND OTHER INTANGIBLE ASSETS

($ millions)	Oil Sands Goodwill	Refining and Marketing Goodwill	Brand name	Customer lists	Total
At January 1, 2010	3 019	182	166	66	3 433
Amortization	—	—	—	(11)	(11)
At December 31, 2010	3 019	182	166	55	3 422
Derecognition of goodwill (note 33)	**(267)**	**(8)**	**—**	**—**	**(275)**
Additions	**—**	**—**	**—**	**3**	**3**
Amortization	**—**	**—**	**—**	**(11)**	**(11)**
At December 31, 2011	**2 752**	**174**	**166**	**47**	**3 139**

The company performed its most recent goodwill impairment test at July 31, 2011. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs to sell calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plan have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset.

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserve volumes, operating costs, maintenance and capital expenditures are consistent with the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test.

Future cash flow estimates are adjusted to reflect risks specific to the asset and discounted using after-tax discount rates. The discount rate is calculated based on the weighted-average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 11% at July 31, 2011 (July 31, 2010 – 11%) with a growth rate equal to the current inflation rate of 2% (July 31, 2010 – 2%). As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

22. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Commercial paper (1)	**761**	1 982	2 315
Other	**2**	2	2
Total short-term debt	**763**	1 984	2 317

(1) The commercial paper is supported by a revolving credit facility with a separate lender. The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. The weighted-average interest rate as at December 31, 2011 was 0.4% (December 31, 2010 – 1.2%, January 1, 2010 – 0.5%).

Long-Term Debt

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Fixed-term debt, redeemable at the option of the company			
6.85% Notes, due 2039 (US$750)	**763**	746	785
6.80% Notes, due 2038 (US$900)	**942**	922	972
6.50% Notes, due 2038 (US$1150)	**1 170**	1 144	1 204
5.95% Notes, due 2035 (US$600)	**566**	552	578
5.95% Notes, due 2034 (US$500)	**509**	497	523
5.35% Notes, due 2033 (US$300)	**263**	255	266
7.15% Notes, due 2032 (US$500)	**509**	497	523
6.10% Notes, due 2018 (US$1250)	**1 271**	1 243	1 308
6.05% Notes, due 2018 (US$600)	**621**	609	643
5.00% Notes, due 2014 (US$400)	**413**	406	429
4.00% Notes, due 2013 (US$300)	**305**	298	313
7.00% Debentures, due 2028 (US$250)	**263**	257	271
7.875% Debentures, due 2026 (US$275)	**312**	307	325
9.25% Debentures, due 2021 (US$300)	**376**	375	402
5.39% Series 4 Medium Term Notes, due 2037	**600**	600	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700	700
6.70% Series 2 Medium Term Notes, due 2011 (1)	**—**	500	500
	9 583	9 908	10 342
Revolving-term debt, with variable interest rates			
Bankers' acceptances and LIBOR loans (weighted-average interest rate at January 1, 2010 – 0.9%)	**—**	—	929
Total unsecured long-term debt	**9 583**	9 908	11 271
Secured long-term debt	**13**	13	13
Finance leases (2)	**476**	477	465
Fair value adjustment related to interest rate swaps	**—**	8	18
Deferred financing costs	**(56)**	(59)	(63)
	10 016	10 347	11 704
Current portion of long-term debt			
6.70% Series 2 Medium Term Notes, due 2011 (1)	**—**	(500)	—
Finance leases (2)	**(12)**	(10)	(14)
Fair value adjustment related to interest swaps	**—**	(8)	(11)
	(12)	(518)	(25)
Total long-term debt	**10 004**	9 829	11 679

(1) The company entered into an interest rate swap transaction on $200 million of the principal amount of this note. In August 2011, the principal was repaid and the interest rate swap instruments expired. The interest rate swaps resulted in an average effective interest rate on the $200 million principal of 2.5% for the first seven months of 2011 (2010 – 1.9%).

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

Required Debt Repayments

Required debt repayments for finance leases, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2012	775
2013	331
2014	421
2015	16
2016	17
Thereafter	9 205
Total	10 765

Credit Facilities

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

($ millions)	2011
Fully revolving for a period of one year and expires in 2013	**2 000**
Fully revolving for a period of four years and expires in 2013	**203**
Fully revolving for a period of five years and expires in 2016	**3 000**
Can be terminated at any time at the option of the lenders	**612**
Total available credit facilities	**5 815**
Credit facilities supporting outstanding commercial paper	**(761)**
Credit facilities supporting standby letters of credit	**(626)**
Total unutilized credit facilities	**4 428**

23. OTHER LONG-TERM LIABILITIES

($ millions)	Dec 31 2011	Dec 31 2010	Jan 1 2010
Pensions and other post-retirement benefits (note 24)	**1 683**	1 275	1 143
Share-based compensation plans (note 27)	**187**	331	224
Deferred revenue	**84**	94	94
Fort Hills purchase obligation (1)	**275**	327	322
Libya EPSAs signature bonus (2)	**73**	38	280
Other	**90**	38	10
	2 392	2 103	2 073

(1) 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, 2011, the carrying amount of the Fort Hills obligation, based on the discounted estimated payout pattern for the funding, was $327 million (2010 – $327 million), of which the current portion is $52 million (2010 – $nil) and is recorded in Accounts Payable and Accrued Liabilities.

(2) 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 (EPSAs) in Libya payable in several instalments to be paid through 2013. The company also has a US$47 million obligation related to merger consent. At December 31, 2011, the carrying amount of the total Libya obligation was $342 million (2010 – $287 million), of which the current portion is $269 million (2010 – $249 million) and is recorded in Accounts Payable and Accrued Liabilities.

24. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The company's defined benefit pension plans provide 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. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. 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, 2011. The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation for accounting purposes.

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 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 9% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Change in benefit obligation				
Benefit obligation at beginning of year	**3 219**	2 875	**462**	401
Current service costs	**111**	87	**10**	10
Plan participants' contributions	**13**	11	**—**	—
Benefits paid	**(161)**	(151)	**(17)**	(12)
Interest costs	**165**	168	**23**	24
Foreign exchange	**(18)**	(14)	**—**	(1)
Settlements	**(6)**	—	**—**	—
Actuarial loss	**375**	243	**32**	40
Benefit obligation at end of year	**3 698**	3 219	**510**	462
Change in plan assets				
Fair value of plan assets at beginning of year	**2 335**	2 072	**—**	—
Employer contributions	**205**	188	**—**	—
Plan participants' contributions	**13**	11	**—**	—
Benefits paid	**(161)**	(151)	**—**	—
Foreign exchange	**3**	(9)	**—**	—
Settlements	**(7)**	—	**—**	—
Expected return on plan assets	**160**	142	**—**	—
Actuarial gain (loss)	**(49)**	82	**—**	—
Fair value of plan assets at end of year	**2 499**	2 335	**—**	—
Net unfunded obligation	**1 199**	884	**510**	462

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Analysis of amount charged to earnings:				
Current service costs	**111**	87	**10**	10
Interest costs	**165**	168	**23**	24
Settlement	**1**	—	**—**	—
Expected return on plan assets	**(160)**	(142)	**—**	—
Defined benefit plans expense	**117**	113	**33**	34
Defined contribution plans expense	**43**	40	**—**	—
Total benefits plans expense charged to earnings	**160**	153	**33**	34
Analysis of amount recognized in other comprehensive income:				
Actual return less expected return on plan assets	**49**	(82)	**—**	—
Change in assumptions underlying the present value of the plan liabilities	**367**	240	**(3)**	45
Experience gains and losses arising on the plan liabilities	**8**	3	**35**	(5)
Actuarial loss recognized in other comprehensive income	**424**	161	**32**	40

Accumulated actuarial losses in retained earnings at December 31, 2011 were $657 million (December 31, 2010 – $201 million).

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as projection of salaries and service to retirement.

The significant weighted-average actuarial assumptions were as follows:

(per cent)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Benefit Obligation at December 31				
Discount rate	**4.40**	5.10	**4.40**	5.25
Rate of compensation increase	**3.70**	3.70	**3.70**	4.00
Benefit Plans Expense year ended December 31				
Discount rate	**5.10**	5.85	**5.25**	6.00
Expected return on plan assets	**6.70**	6.65	**N/A**	N/A
Rate of compensation increase	**3.70**	3.90	**4.00**	4.00

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The expected return on plan assets is the expected long-term rate of return on plan assets for the year and 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.

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.

In order to measure the expected cost of other post-retirement benefits, a 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 (2010 – 8%). It is assumed this rate will remain constant in 2012 and 2013 and will decrease 0.5% annually to 5% by 2017, and remain at that level thereafter.

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
Effect on the aggregate service and interest costs	3	(2)
Effect on the benefit obligations	43	(35)

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, 2011 and 2010, are as follows:

(per cent)	2011	2010
Equities	**55**	58
Fixed income	**45**	42
Total	**100**	100

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

The company expects to make cash contributions to its defined benefit pension plans in 2012 of $280 million.

25. PROVISIONS

($ millions)	Decommissioning and Restoration [1]	Royalties [2]	Other	Total
At January 1, 2010	3 496	421	270	4 187
Liabilities incurred	80	145	212	437
Changes in estimates	(183)	(86)	64	(205)
Liabilities settled	(417)	(110)	(136)	(663)
Accretion	186	—	15	201
Asset divestitures	(470)	—	—	(470)
Foreign exchange	(59)	—	(5)	(64)
At December 31, 2010	2 633	370	420	3 423
Less: current portion	147	370	91	608
Less: associated with assets held for sale	311	—	—	311
	2 175	—	329	2 504
At December 31, 2010	2 633	370	420	3 423
Liabilities incurred	**219**	**237**	**42**	**498**
Changes in estimates	**1 690**	**4**	**1**	**1 695**
Liabilities settled	**(496)**	**(256)**	**(63)**	**(815)**
Accretion	**140**	**—**	**6**	**146**
Asset divestitures	**(390)**	**—**	**—**	**(390)**
Foreign exchange	**5**	**—**	**1**	**6**
At December 31, 2011	**3 801**	**355**	**407**	**4 563**
Less: current portion	**372**	**355**	**84**	**811**
	3 429	**—**	**323**	**3 752**

(1) Represents decommissioning and restoration provisions associated with the retirement of property, plant and equipment. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2011 was approximately $7.3 billion (December 31, 2010 – $5.5 billion). A weighted-average credit-adjusted risk-free interest rate of 4.3% was used to discount the provision recognized at December 31, 2011 (December 31, 2010 – 5.4%). The credit-adjusted risk-free rate used reflects the expected timeframe of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years.

(2) In 2010, the Minister of Energy for Alberta provided notice to the company for the quality and transportation adjustments to be used under the Bitumen Valuation Methodology (Ministerial) Regulations for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015. As a result, in 2010 the company recognized a recovery of provision amounts previously recorded in 2009 of $65 million. The company is still pursuing final settlement of the quality adjustment.

26. 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.

Normal Course Issuer Bid

In the third quarter of 2011, the company announced a Normal Course Issuer Bid (NCIB) to purchase for cancellation up to $500 million of its common shares between September 6, 2011 and September 5, 2012. During the year, the company completed the NCIB by purchasing 17.1 million common shares for total consideration of $500 million. Of the amount paid, $222 million was charged to share capital and $278 million to retained earnings.

27. SHARE-BASED COMPENSATION

(a) Stock Option Plans

Stock options that give the holder the right to purchase common shares at the grant date market price subject to fulfilling vesting terms are accounted for as equity-settled plans. Stock options that the holder can settle for cash or common shares are accounted for as cash-settled plans.

Equity-Settled Stock Option 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. Options granted have a seven-year life and vest annually over a three-year period.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, Key Contributor Stock Options, and legacy Petro-Canada Stock Options. For details of the terms and conditions of these plans, refer to the company's 2010 audited annual financial statements.

Fair values of options accounted for as equity-settled 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:

	2011	2010
Annual dividend per share	**$0.43**	$0.40
Risk-free interest rate	**2.50%**	2.02%
Expected life	**5 years**	5 years
Expected volatility	**49%**	50%
Weighted-average fair value per option	**$16.52**	$12.98

The expected life is based on historical experience and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Cash-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options with TSARs

Options were granted under this plan between August 1, 2009 and July 31, 2010. Each option included a tandem stock appreciation right (TSAR). Options granted have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada Stock Options with CPAs

This plan was discontinued on August 1, 2009. Options were granted to executives and key employees, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life and vest over periods of up to four years.

Fair values of options accounted for as cash-settled are estimated as at the reporting date using the Black-Scholes option-pricing model. The expected life assumption is based on historical data and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Changes in the total outstanding stock options were as follows:

	2011		2010	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**67 638**	**32.94**	72 024	32.52
Granted	**5 840**	**41.08**	4 297	31.86
Exercised	**(9 918)**	**20.93**	(5 292)	15.49
Forfeited/expired	**(4 382)**	**40.51**	(3 391)	42.51
Outstanding, end of year	**59 178**	**35.25**	67 638	32.94
Exercisable, end of year	**39 482**	**32.03**	46 266	29.91

Options are exercised regularly throughout the year. Therefore, the weighted-average share price during the year of $36.18 (2010 – $33.73) is representative of the weighted-average share price at the date of exercise.

For the options outstanding at December 31, 2011, the exercise price ranges and weighted-average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)
11.96-14.99	7 346	1
15.00-29.99	10 503	3
30.00-45.99	23 636	4
46.00-49.99	16 575	3
50.00-69.97	1 118	3
Total	59 178	3

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

(thousands)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
	10 347	12 785	16 196

(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, and is accounted for as a cash-settled plan.

(i) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Fair values of SARs are estimated under the same methodology used for cash-settled stock options. Changes in the number of outstanding SARs were as follows:

	2011		2010	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**11 285**	**28.97**	14 065	28.63
Granted	**197**	**41.26**	353	31.85
Exercised	**(2 003)**	**29.54**	(734)	24.00
Forfeited/expired	**(727)**	**28.10**	(2 399)	28.99
Outstanding, end of year	**8 752**	**29.32**	11 285	28.97
Exercisable, end of year	**5 625**	**31.49**	4 939	32.28

(c) Share Unit Plans

The company's share unit plans are accounted for as cash-settled 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 the 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. Executives may elect to receive one-half, or all, of their annual incentive payment in the form of DSUs.

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

(thousands)	PSU	RSU	DSU
Outstanding, January 1, 2010	3 247	4 250	2 616
Granted	1 699	2 881	109
Redeemed for cash	(282)	(118)	(426)
Forfeited/expired	(917)	(563)	—
Outstanding, December 31, 2010	3 747	6 450	2 299
Granted	**2 050**	**4 237**	**152**
Redeemed for cash	**(224)**	**(840)**	**(749)**
Forfeited/expired	**(913)**	**(553)**	**—**
Outstanding, December 31, 2011	**4 660**	**9 294**	**1 702**

Fair values are estimated as at the reporting date using the Monte-Carlo simulation approach for PSUs and the Black-Scholes option-pricing model for other share unit plans. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the share units is indicative of future trends.

Share-Based Compensation Expense (Recovery)

The following table summarizes the share-based compensation expense (recovery) recorded for all plans within Operating, Selling and General expense in the Consolidated Statements of Comprehensive Income.

($ millions)	**2011**	2010
Equity-settled plans	**94**	4
Cash-settled plans	**(95)**	190
Total share-based compensation expense (recovery)	**(1)**	194

Liability Recognized for Share-Based Compensation

The company has recorded a liability of $405 million as at December 31, 2011 (2010 – $666 million), of which $218 million was classified as current (2010 – $335 million), based on the fair value of awards accounted for as cash-settled. The intrinsic value of the vested awards at December 31, 2011 was $161 million (2010 – $225 million).

28. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and portions of other assets and other long-term liabilities.

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 fair value of the company's financial instrument included in other assets was calculated using a discounted cash flow model. The inputs used in the model were based on observable market data, where available.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method, except for a portion of debt that was recorded at fair value as part of a fair value hedging relationship until August 2011 (see note 22). At December 31, 2011, the carrying value of fixed-term debt accounted for under amortized cost was $9.6 billion (December 31, 2010 – $9.7 billion) and the fair value at December 31, 2011 was $11.4 billion (December 31, 2010 – $10.7 billion).

Derivative Financial Instruments

(a) Fair Value Hierarchy

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 at December 31, 2011:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	11	3	13	27
Accounts payable	(72)	(14)	(7)	(93)
Balance at December 31, 2010	(61)	(11)	6	(66)
Accounts receivable	**1**	**33**	**3**	**37**
Accounts payable	**(18)**	**(51)**	**(2)**	**(71)**
Balance at December 31, 2011	**(17)**	**(18)**	**1**	**(34)**

(b) Designated as Part of a Qualifying Hedge Relationship

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. During 2011, the company held interest rate swaps designated as fair value hedges on $200 million of fixed-term debt. These swaps expired in August 2011. The fair value of these swaps as at December 31, 2010 was $8 million.

(c) Non-Designated 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 managing exposure to commodity price movements and are a component of Suncor's overall risk management program.

Gains or losses associated with risk management derivatives are reported in the related operating segment as part of Other Income. The earnings impact associated with these contracts for the year ended December 31, 2011 was a loss of $22 million (2010 – gain of $89 million).

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues.

Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations. The earnings impact for the year ended December 31, 2011 was a gain of $301 million (2010 – gain of $106 million).

Change in Fair Value of Non-Designated Derivative Financial Instruments

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding at January 1, 2010	(312)	(47)	(359)
Fair value of contracts realized during the period	236	(146)	90
Changes in fair value during the period	89	106	195
Fair value of contracts outstanding at December 31, 2010	13	(87)	(74)
Fair value of contracts realized during the period	**9**	**(248)**	**(239)**
Changes in fair value during the period	**(22)**	**301**	**279**
Fair value of contracts outstanding at December 31, 2011	**—**	**(34)**	**(34)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, 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 trading and credit risk management activities. Trading activities are defined as strategic hedging, optimization trading, marketing and trading. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2010.

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

Suncor'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 may reduce its exposure to commodity price risk through a number of strategies. These strategies include committing a portion of expected crude oil production to fixed price contracts, entering into option contracts to limit exposure to changes in crude oil prices and hedging natural gas exposures to manage regional price differentials.

Changes in crude oil and natural gas prices would have the following impact on pre-tax earnings for the company's outstanding derivative financial instruments at December 31, 2011 and 2010:

($ millions)	2011 (1)	Change	Pre-tax Earnings
Crude Oil	US$96.12/barrel		
Price increase		US$1.00/barrel	(8)
Price decrease		US$1.00/barrel	8
Natural Gas	US$3.56/mcf		
Price increase		US$0.10/mcf	(1)
Price decrease		US$0.10/mcf	1

($ millions)	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 the average of futures' prices at December 31, 2011 and 2010, respectively.

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. A 1% change in the US$/Cdn$ exchange rate at December 31, 2011 would change pre-tax earnings by approximately $88 million (2010 – $90 million).

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars or Euros (€). A 1% change in the US$/Cdn$ exchange rate and €/Cdn$ exchange rate at December 31, 2011 would impact other comprehensive income by approximately $45 million and $23 million, respectively (2010 – $37 million and $23 million, respectively).

(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 its 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. Over time, 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 at December 31, 2011 was 7% of total debt outstanding (2010 – 18%). The weighted-average interest rate on total debt for the year ending December 31, 2011 was 6.0% (2010 – 5.7%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $8 million (2010 – $22 million). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2011, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements and maintaining sufficient cash and credit facilities to meet these requirements. Suncor's cash and cash equivalents and available credit facilities at December 31, 2011 were $3.8 billion and $5.8 billion, respectively.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is maintained through counterparty credit limits.

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

	December 31, 2011		December 31, 2010	
($ millions)	**Trade and other payables (1)**	**Debt (2)**	Trade and other payables (1)	Debt (2)
Within one year	**7 755**	**1 411**	6 524	3 128
1 to 3 years	**274**	**2 012**	359	1 562
3 to 5 years	**52**	**1 238**	32	1 615
Over 5 years	**—**	**17 259**	—	17 473
Total	**8 081**	**21 920**	6 915	23 778

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

(2) Debt includes short-term debt, long-term debt, finance 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's credit policy 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, 2011 and 2010, substantially all of the company's trade receivables were current. However, as a result of political unrest in Syria, the company has not received payment for recent production from its Syrian operations. The company has recorded a provision of $63 million against these receivables, which represents approximately half of the overall balance outstanding.

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, 2011, the company's exposure was $37 million (December 31, 2010 – $27 million).

29. 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 agreements 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, 2011 and 2010.

The company's strategy during 2011, which was unchanged from 2010, 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's targets.

At December 31 ($ millions)	Capital Measure Target	**2011**	2010
Components of ratios			
Short-term debt		**763**	1 984
Current portion of long-term debt		**12**	518
Long-term debt		**10 004**	9 829
Total debt		**10 779**	12 331
Less: Cash and cash equivalents		**3 803**	1 077
Net debt		**6 976**	11 254
Shareholders' equity		**38 600**	35 192
Total capitalization (total debt plus shareholders' equity)		**49 379**	47 523
Cash flow from operations(1)		**9 746**	6 656
Net debt to cash from operations	<2.0 times	**0.7**	1.7
Total debt to total debt plus shareholders' equity		**22%**	26%

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

30. INTERESTS IN JOINT VENTURES

Significant jointly controlled entities at December 31, 2011 are set out below:

	%
Fort Hills Energy L.P.[(1)]	40.8
Syncrude Canada Ltd.[(2)]	12.0
Voyageur Upgrader L.P.[(3)]	51.0
Magrath Windfarm Joint Venture	33.3
Chin Chute Windfarm Joint Venture	33.3
Ripley Windfarm Joint Venture	50.0
Wintering Hills Joint Venture	70.0
Chimies Parachem S.E.C. / Parachem Chemicals L.P.	51.0
UPI Inc.	50.0

(1) The company's share of Fort Hills Energy L.P. was 60.0% at January 1, 2010 and December 31, 2010.

(2) Syncrude Canada Ltd. is the operator of the Syncrude oil sands joint venture, a jointly controlled asset. Syncrude Canada Ltd. is responsible for the management and administration of this asset.

(3) Voyageur Upgrader L.P. was a wholly-owned subsidiary at January 1, 2010 and December 31, 2010.

Summarized financial information for the company's share of its jointly controlled entities is shown below:

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Current assets	**127**	128	101
Non-current assets	**2 935**	1 227	1 246
	3 062	1 355	1 347
Current liabilities	**135**	183	148
Non-current liabilities	**146**	64	110
	281	247	258
Revenues and other income	**541**	672	
Expenses	**746**	852	
Net earnings	**(205)**	(180)	

31. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business. These are primarily sales to associated entities in the company's refining and marketing operations. Operating revenues after eliminations for these transactions were $780 million for the year ended December 31, 2011 (2010 – $730 million). At December 31, 2011, amounts due from related parties were $60 million (2010 – $60 million).

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2011**	2010
Short-term benefits	**17**	13
Pension and other post-retirement benefits	**3**	3
Share-based compensation	**29**	38
	49	54

32. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Operating Commitments

Future payments under the company's operating leases for pipeline transportation agreements and for various premises, service stations and other property and equipment are as follows:

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Within one year	**1 080**	1 126	1 077
After one year but not more than five years	**3 768**	3 409	3 281
More than five years	**8 785**	8 386	8 019
	13 633	12 921	12 377

Significant operating leases expire at various dates through 2028. For the year ended December 31, 2011, operating lease expense was $1.1 billion (2010 – $1.0 billion).

Suncor also has commodity purchase arrangements which are transacted at market prices and in the normal course of business, which may terminate on short notice.

(b) Contingencies

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 property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2011, 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 limits. The company also has primary property insurance for US$250 million that covers all of Suncor's assets. As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million on certain foreign operations, of which up to $300 million can apply to our assets in Syria.

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

At December 31, 2011, the company had various indemnification agreements with third parties as described below and provides loan guarantees to certain retail licensees.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 22) for added costs relating to withholding taxes. 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, the company has the option to redeem or terminate these contracts if additional costs are incurred.

33. JOINT VENTURE WITH TOTAL

In March 2011, Suncor closed the previously announced transaction 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 the construction of the Voyageur upgrader.

As a result of this transaction, Suncor acquired a 36.75% interest in Joslyn for consideration of $842 million after closing adjustments. Total acquired a 49% interest in Voyageur, a 19.2% increase in its interest in Fort Hills (reducing Suncor's interest from 60% to 40.8%), and rights to proprietary mining technology, for cash consideration of $2.662 billion after closing adjustments.

Overall, Suncor recognized a loss of $124 million, after final closing adjustments, related to the disposition of its interests in Voyageur and Fort Hills and the technology sale. The loss included the derecognition of $267 million of goodwill associated with the disposed interests in Fort Hills and Voyageur.

34. SUBSEQUENT EVENT

On February 23, 2012, the company announced that it would recommence its Normal Course Issuer Bid (NCIB), and may purchase for cancellation an additional $1 billion of its common shares between February 28, 2012 and September 5, 2012.

QUARTERLY FINANCIAL SUMMARY

(unaudited)

($ millions except per share amounts)	**For the Quarter Ended Mar 31 2011**	**June 30 2011**	**Sept 30 2011**	**Dec 31 2011**	**Total Year 2011**	For the Quarter Ended Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010	Total Year 2010
Revenues and other income (A)	**9 388**	**9 587**	**10 678**	**10 137**	**39 790**	7 131	8 461	7 672	9 340	32 604
Net earnings (loss)										
Oil Sands	**605**	**371**	**837**	**790**	**2 603**	89	534	413	484	1 520
Exploration and Production	**(186)**	**(212)**	**420**	**284**	**306**	528	343	681	386	1 938
Refining and Marketing	**627**	**313**	**479**	**307**	**1 726**	147	146	159	367	819
Corporate, Energy Trading and Eliminations	**(18)**	**90**	**(449)**	**46**	**(331)**	15	(483)	(29)	49	(448)
	1 028	**562**	**1 287**	**1 427**	**4 304**	779	540	1 224	1 286	3 829
Operating earnings (loss) (B)										
Oil Sands	**694**	**371**	**837**	**835**	**2 737**	90	542	402	345	1 379
Exploration and Production	**337**	**260**	**389**	**372**	**1 358**	332	303	283	275	1 193
Refining and Marketing	**627**	**313**	**479**	**307**	**1 726**	147	124	159	366	796
Corporate, Energy Trading and Eliminations	**(180)**	**36**	**84**	**(87)**	**(147)**	(199)	(130)	(227)	(178)	(734)
	1 478	**980**	**1 789**	**1 427**	**5 674**	370	839	617	808	2 634
Cash flow from (used in) operations										
Oil Sands	**1 137**	**733**	**1 285**	**1 417**	**4 572**	265	937	779	796	2 777
Exploration and Production	**583**	**682**	**801**	**780**	**2 846**	848	760	769	948	3 325
Refining and Marketing	**929**	**500**	**611**	**534**	**2 574**	328	270	330	610	1 538
Corporate, Energy Trading and Eliminations	**(256)**	**67**	**24**	**(81)**	**(246)**	(317)	(197)	(248)	(222)	(984)
	2 393	**1 982**	**2 721**	**2 650**	**9 746**	1 124	1 770	1 630	2 132	6 656
Per common share										
Net earnings										
– basic	**0.65**	**0.36**	**0.82**	**0.91**	**2.74**	0.50	0.35	0.78	0.82	2.45
– diluted	**0.65**	**0.31**	**0.76**	**0.91**	**2.67**	0.46	0.34	0.78	0.82	2.43
Operating earnings – basic	**0.94**	**0.62**	**1.14**	**0.91**	**3.61**	0.24	0.54	0.39	0.52	1.69
Cash flow from operations – basic	**1.52**	**1.26**	**1.73**	**1.69**	**6.20**	0.72	1.13	1.04	1.36	4.25

(A) During the second quarter of 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities income and expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Prior period comparative figures have been reclassified for comparability with current presentation.

(B) Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance.

QUARTERLY OPERATING SUMMARY

(unaudited)

Oil Sands	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011	For the Quarter Ended Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010	Total Year 2010
Production (mbbls/d)										
Total production (excluding Syncrude)	**322.1**	**243.4**	**326.6**	**326.5**	**304.7**	202.3	295.5	306.6	325.9	283.0
Firebag (mbbls/d of bitumen)	**55.2**	**56.4**	**54.8**	**71.7**	**59.5**	55.7	55.7	50.4	52.9	53.6
MacKay River (mbbls/d of bitumen)	**32.1**	**29.4**	**29.0**	**29.7**	**30.0**	31.8	32.5	28.8	32.9	31.5
Syncrude	**38.5**	**33.8**	**35.9**	**30.3**	**34.6**	32.3	38.9	31.7	37.9	35.2
Sales (mbbls/d) (excluding Syncrude)										
Light sweet crude oil	**101.0**	**50.5**	**80.4**	**109.9**	**85.5**	61.0	99.0	84.5	84.5	82.3
Diesel	**18.5**	**11.5**	**30.7**	**36.1**	**24.3**	12.9	30.7	25.8	12.2	20.4
Light sour crude oil	**183.0**	**146.8**	**194.6**	**158.1**	**170.6**	80.5	143.1	165.8	189.8	145.2
Bitumen	**23.7**	**34.0**	**24.0**	**14.5**	**24.0**	42.3	37.4	21.2	24.9	31.4
Total sales	**326.2**	**242.8**	**329.7**	**318.6**	**304.4**	196.7	310.2	297.3	311.4	279.3
Average sales price(1) **(excluding Syncrude)** (dollars per barrel)										
Light sweet crude oil*	**90.47**	**107.96**	**95.75**	**103.51**	**98.50**	80.84	77.55	75.49	83.02	79.03
Other (diesel, light sour crude oil and bitumen)*	**79.05**	**85.98**	**81.65**	**94.07**	**84.93**	69.53	68.53	66.39	70.29	68.63
Total *	**82.59**	**90.56**	**85.09**	**97.33**	**88.74**	73.03	71.41	68.97	73.75	71.69
Total	**82.59**	**90.56**	**85.09**	**97.33**	**88.74**	70.21	69.79	67.53	70.95	69.58
Syncrude average sales price(1) (dollars per barrel)	**93.33**	**111.86**	**98.35**	**105.33**	**101.80**	83.21	77.32	78.83	84.40	80.93
Operating costs (excluding Syncrude) (dollars per barrel)										
Cash costs	**33.60**	**46.25**	**34.70**	**37.20**	**37.40**	46.15	31.45	32.15	34.35	35.05
Natural gas	**2.55**	**2.95**	**1.90**	**2.40**	**2.45**	5.40	3.55	1.10	2.30	2.85
Imported diluent**	**–**	**1.80**	**–**	**–**	**0.35**	2.95	0.70	0.05	0.05	0.75
Cash operating costs(2)	**36.15**	**51.00**	**36.60**	**39.60**	**40.20**	54.50	35.70	33.30	36.70	38.65
Project start-up costs	**1.30**	**2.05**	**1.95**	**0.70**	**1.45**	0.55	0.55	0.70	0.95	0.70
Total cash operating costs(3)	**37.45**	**53.05**	**38.55**	**40.30**	**41.65**	55.05	36.25	34.00	37.65	39.35
Depreciation, depletion and amortization	**8.30**	**13.10**	**9.90**	**11.55**	**10.55**	12.10	15.15	8.90	9.15	11.15
Total operating costs(4)	**45.75**	**66.15**	**48.45**	**51.85**	**52.20**	67.15	51.40	42.90	46.80	50.50
Operating costs – Syncrude*** (dollars per barrel)										
Cash costs	**35.30**	**37.40**	**38.50**	**46.15**	**39.05**	39.60	28.75	39.20	32.85	34.70
Natural gas	**3.40**	**3.15**	**2.70**	**3.05**	**3.10**	4.50	2.85	2.75	3.05	3.25
Cash operating costs(2)	**38.70**	**40.55**	**41.20**	**49.20**	**42.15**	44.10	31.60	41.95	35.90	37.95
Project start-up costs	**–**	**–**	**–**	**–**	**–**	–	–	–	–	–
Total cash operating costs(3)	**38.70**	**40.55**	**41.20**	**49.20**	**42.15**	44.10	31.60	41.95	35.90	37.95
Depreciation, depletion and amortization	**20.25**	**14.10**	**11.75**	**16.05**	**15.60**	13.70	11.35	14.85	12.55	13.00
Total operating costs(4)	**58.95**	**54.65**	**52.95**	**65.25**	**57.75**	57.80	42.95	56.80	48.45	50.95
Operating costs – In situ bitumen production only (dollars per barrel)										
Cash costs	**16.60**	**18.50**	**21.50**	**24.00**	**20.30**	12.30	13.65	17.15	16.50	14.85
Natural gas	**5.40**	**5.65**	**5.55**	**5.15**	**5.40**	7.05	5.05	5.25	4.80	5.55
Cash operating costs(5)	**22.00**	**24.15**	**27.05**	**29.15**	**25.70**	19.35	18.70	22.40	21.30	20.40
Project start-up costs	**4.20**	**5.20**	**6.30**	**0.50**	**3.90**	0.95	1.45	2.50	3.35	2.05
Total cash operating costs(6)	**26.20**	**29.35**	**33.35**	**29.65**	**29.60**	20.30	20.15	24.90	24.65	22.45
Depreciation, depletion and amortization	**5.65**	**6.30**	**7.05**	**9.90**	**7.35**	5.05	4.70	5.90	5.55	5.30
Total operating costs(7)	**31.85**	**35.65**	**40.40**	**39.55**	**36.95**	25.35	24.85	30.80	30.20	27.75

Footnotes and definitions, see page 136.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Exploration and Production	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011	For the Quarter Ended Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010	Total Year 2010
Total Production (mboe/d)	**240.7**	**182.8**	**183.5**	**219.7**	**206.7**	330.0	299.5	297.2	261.8	296.9
North America Onshore										
Production										
Natural gas (mmcf/d)	**379**	**370**	**346**	**335**	**357**	649	536	500	407	522
Natural gas liquids and crude oil (mbbls/d)	**5.4**	**5.3**	**4.8**	**5.0**	**5.1**	14.0	8.3	7.6	5.1	8.8
Total production (mmcfe/d)	**411**	**402**	**375**	**365**	**388**	733	586	546	438	575
Average sales price [1]										
Natural gas (dollars per mcf)	**3.72**	**3.75**	**3.52**	**3.18**	**3.55**	5.32	3.46	3.71	3.38	4.04
Natural gas liquids and crude oil (dollars per barrel)	**77.85**	**88.90**	**83.98**	**90.58**	**85.30**	66.07	72.73	60.16	71.02	67.06
East Coast Canada										
Production (mbbls/d)										
Terra Nova	**16.9**	**14.4**	**19.4**	**14.3**	**16.2**	29.6	27.2	17.2	19.0	23.2
Hibernia	**29.2**	**32.1**	**32.0**	**30.2**	**30.9**	30.2	30.1	32.3	30.9	30.9
White Rose	**18.9**	**18.5**	**17.7**	**18.9**	**18.5**	14.8	13.3	16.8	13.0	14.5
	65.0	**65.0**	**69.1**	**63.4**	**65.6**	74.6	70.6	66.3	62.9	68.6
Average sales price [1]										
(dollars per barrel)	**104.01**	**112.19**	**111.30**	**111.77**	**108.42**	78.69	76.88	78.78	87.12	80.20
International										
Production (mboe/d)										
North Sea										
Buzzard	**50.3**	**32.7**	**33.1**	**55.0**	**42.9**	58.6	49.3	58.6	55.6	55.5
Other North Sea	**15.4**	**–**	**–**	**–**	**3.8**	27.5	22.7	25.2	18.7	23.5
Other International										
Libya	**24.1**	**–**	**–**	**24.6**	**12.1**	35.4	35.4	35.4	34.7	35.2
Syria	**17.4**	**18.1**	**18.8**	**15.9**	**17.6**	–	12.8	16.5	16.9	11.6
Trinidad and Tobago	**–**	**–**	**–**	**–**	**–**	11.7	11.1	4.2	–	6.7
	107.2	**50.8**	**51.9**	**95.5**	**76.4**	133.2	131.3	139.9	125.9	132.5
Average sales price [1] (dollars per boe)										
Buzzard	**94.12**	**113.24**	**111.60**	**106.41**	**105.18**	72.36	78.57	75.60	85.46	77.91
Other North Sea	**92.49**	**–**	**–**	**–**	**92.49**	76.10	72.01	79.40	82.77	78.16
Other International	**91.92**	**91.42**	**93.94**	**102.42**	**95.76**	59.81	64.98	70.22	83.06	70.39

Footnotes and definitions, see page 136.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Refining and Marketing	For the Quarter Ended Mar 31 2011	June 30 2011	Sept 30 2011	Dec 31 2011	Total Year 2011	For the Quarter Ended Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010	Total Year 2010
Eastern North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**21.1**	**20.9**	**21.4**	**20.1**	**20.9**	21.0	22.5	22.5	22.9	22.2
Distillate	**13.4**	**12.8**	**12.7**	**12.2**	**12.8**	12.3	12.5	11.7	13.7	12.4
Total transportation fuel sales	**34.5**	**33.7**	**34.1**	**32.3**	**33.7**	33.3	35.0	34.2	36.6	34.6
Petrochemicals	**2.3**	**2.2**	**2.3**	**1.7**	**2.1**	2.2	2.8	2.5	2.4	2.5
Asphalt	**1.7**	**2.2**	**3.5**	**2.2**	**2.4**	1.8	3.0	3.7	2.4	2.7
Other	**6.1**	**6.2**	**4.4**	**4.6**	**5.3**	4.3	6.0	6.0	5.3	5.5
Total refined product sales	**44.6**	**44.3**	**44.3**	**40.8**	**43.5**	41.6	46.8	46.4	46.7	45.3
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**33.1**	**31.9**	**32.3**	**30.7**	**32.0**	31.0	30.6	30.7	29.7	30.5
Utilization of refining capacity (%)	**97**	**94**	**94**	**90**	**94**	91	90	90	87	89
Western North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**17.0**	**18.6**	**19.7**	**19.7**	**18.8**	18.1	19.2	19.9	18.3	18.9
Distillate****	**17.9**	**16.2**	**18.7**	**17.5**	**17.6**	16.9	16.3	17.4	21.3	18.0
Total transportation fuel sales	**34.9**	**34.8**	**38.4**	**37.2**	**36.4**	35.0	35.5	37.3	39.6	36.9
Asphalt	**0.5**	**1.2**	**1.9**	**1.1**	**1.2**	1.2	1.5	1.5	0.9	1.3
Other	**2.0**	**1.9**	**2.1**	**2.5**	**2.0**	4.4	5.2	3.7	2.0	3.8
Total refined product sales	**37.4**	**37.9**	**42.4**	**40.8**	**39.6**	40.6	42.2	42.5	42.5	42.0
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**35.3**	**27.0**	**36.2**	**32.8**	**32.8**	33.5	31.7	36.6	36.5	34.6
Utilization of refining capacity (%)	**97**	**75**	**100**	**90**	**91**	92	87	101	101	95

Footnotes and definitions, see page 136.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Netbacks	**For the Quarter Ended**				**Total Year**	For the Quarter Ended				Total Year
	Mar 31 2011	**June 30 2011**	**Sept 30 2011**	**Dec 31 2011**	**2011**	Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010	2010
North America Onshore (dollars per mcfe)										
Average price realized [8]	**4.72**	**5.15**	**4.82**	**4.54**	**4.81**	6.29	4.94	4.63	4.47	5.21
Royalties	**(0.44)**	**(0.54)**	**(0.48)**	**(0.48)**	**(0.48)**	(1.02)	(0.12)	(0.54)	(0.44)	(0.56)
Transportation costs	**(0.20)**	**(0.25)**	**(0.26)**	**(0.23)**	**(0.23)**	(0.34)	(0.55)	(0.46)	(0.32)	(0.42)
Operating costs	**(1.49)**	**(1.35)**	**(1.71)**	**(1.66)**	**(1.55)**	(1.32)	(1.45)	(1.44)	(1.72)	(1.47)
Operating netback	**2.59**	**3.01**	**2.37**	**2.17**	**2.55**	3.61	2.82	2.19	1.99	2.76
East Coast Canada (dollars per barrel)										
Average price realized [8]	**105.84**	**114.23**	**112.84**	**114.35**	**110.31**	80.79	78.99	81.06	89.35	82.38
Royalties	**(32.04)**	**(34.99)**	**(33.56)**	**(36.95)**	**(34.49)**	(28.78)	(28.45)	(25.49)	(29.17)	(27.99)
Transportation costs	**(1.83)**	**(2.04)**	**(1.54)**	**(2.58)**	**(1.89)**	(2.10)	(2.11)	(2.28)	(2.23)	(2.18)
Operating costs	**(8.14)**	**(7.26)**	**(6.69)**	**(9.36)**	**(8.04)**	(6.38)	(6.08)	(6.80)	(7.57)	(6.68)
Operating netback	**63.83**	**69.94**	**71.05**	**65.46**	**65.89**	43.53	42.35	46.49	50.38	45.53
North Sea – Buzzard (dollars per barrel)										
Average price realized [8]	**96.09**	**115.21**	**113.65**	**108.43**	**107.18**	74.19	80.35	77.43	87.30	79.73
Transportation costs	**(1.97)**	**(1.97)**	**(2.05)**	**(2.02)**	**(2.00)**	(1.83)	(1.78)	(1.83)	(1.84)	(1.82)
Operating costs	**(3.50)**	**(6.66)**	**(6.34)**	**(3.64)**	**(4.71)**	(3.09)	(3.57)	(2.90)	(2.80)	(3.07)
Operating netback	**90.62**	**106.58**	**105.26**	**102.77**	**100.47**	69.27	75.00	72.70	82.66	74.84
Other North Sea (dollars per boe)										
Average price realized [8]	**94.86**	**–**	**–**	**–**	**94.86**	79.10	75.47	81.13	85.73	80.86
Transportation costs	**(2.37)**	**–**	**–**	**–**	**(2.37)**	(3.00)	(3.46)	(1.73)	(2.96)	(2.70)
Operating costs	**(17.82)**	**–**	**–**	**–**	**(17.82)**	(12.58)	(21.00)	(13.59)	(16.45)	(15.60)
Operating netback	**74.67**	**–**	**–**	**–**	**74.67**	63.52	51.01	65.81	66.32	62.56
Other International (dollars per boe)										
Average price realized [8]	**92.28**	**91.67**	**94.23**	**102.68**	**96.06**	60.20	65.36	70.54	82.74	70.59
Royalties	**(64.12)**	**(41.35)**	**(46.89)**	**(54.06)**	**(54.69)**	(32.55)	(30.06)	(30.30)	(18.37)	(30.67)
Transportation costs	**(0.36)**	**(0.25)**	**(0.29)**	**(0.26)**	**(0.30)**	(0.39)	(0.38)	(0.32)	0.32	(0.20)
Operating costs	**(5.21)**	**(8.48)**	**(6.84)**	**(7.52)**	**(6.75)**	(2.85)	(6.85)	(4.49)	(6.38)	(5.13)
Operating netback	**22.59**	**41.59**	**40.21**	**40.84**	**34.32**	24.41	(28.07)	35.43	58.31	34.59

Footnotes and definitions, see page 136.

FIVE-YEAR FINANCIAL SUMMARY [A]

(unaudited)

($ millions)	**2011**	2010	2009	2008	2007
Revenues and other income					
Oil Sands	**12 233**	9 424	6 539	8 639	6 175
Exploration and Production	**5 309**	5 927	2 305	579	427
Refining and Marketing	**25 771**	20 881	11 851	9 258	8 220
Corporate, Energy Trading and Eliminations [B]	**(3 523)**	(3 628)	4 785	10 161	2 492
	39 790	32 604	25 480	28 637	17 314
Net earnings (loss)					
Oil Sands	**2 603**	1 520	557	2 875	2 474
Exploration and Production	**306**	1 938	78	89	25
Refining and Marketing	**1 726**	819	407	(22)	406
Corporate, Energy Trading and Eliminations	**(331)**	(448)	104	(805)	78
	4 304	3 829	1 146	2 137	2 983
Cash flow from (used in) operations					
Oil Sands	**4 572**	2 777	1 251	3 507	3 165
Exploration and Production	**2 846**	3 325	1 280	367	251
Refining and Marketing	**2 574**	1 538	921	220	660
Corporate, Energy Trading and Eliminations	**(246)**	(984)	(653)	(37)	(39)
	9 746	6 656	2 799	4 057	4 037
Capital and exploration expenditures					
Oil Sands	**5 100**	3 709	2 831	7 413	4 566
Exploration and Production	**874**	1 274	986	342	537
Refining and Marketing	**633**	667	380	207	351
Corporate, Energy Trading and Eliminations	**243**	360	70	58	175
	6 850	6 010	4 267	8 020	5 629
Total assets	**74 777**	68 607	69 746	32 528	24 509
Ending capital employed					
Short-term and long-term debt, less cash and cash equivalents	**6 976**	11 254	13 377	7 226	3 248
Shareholders' equity	**38 600**	35 192	34 111	14 523	11 896
	45 576	46 446	47 488	21 749	15 144
Less capitalized costs related to major projects in progress	**(12 106)**	(12 890)	(13 365)	(6 583)	(4 148)
	33 470	33 556	34 123	15 166	10 996
Total Suncor employees	**13 026**	12 076	12 978	6 798	6 465

Footnotes, see page 132.

FIVE-YEAR FINANCIAL SUMMARY[(A)] (continued)

(unaudited)

($ millions)	**2011**	2010	2009	2008	2007
Dollars per common share					
Net earnings	**2.74**	2.45	0.96	2.29	3.23
Cash dividends	**0.43**	0.40	0.30	0.20	0.19
Cash flow from operations	**6.20**	4.25	2.34	4.36	4.38
Ratios					
Return on capital employed (%)[(C)]	**13.8**	11.4	2.6	22.5	29.3
Return on capital employed (%)[(D)]	**10.1**	8.2	1.8	16.3	21.5
Debt to debt plus shareholders' equity (%)[(E)]	**22**	26	29	35	24
Net debt to cash flow from operations (times)[(F)]	**0.7**	1.7	4.8	1.8	0.8
Interest coverage – cash flow basis (times)[(G)]	**16.4**	11.7	7.2	13.0	23.4
Interest coverage – net earnings basis (times)[(H)]	**10.7**	8.8	3.0	8.9	18.8

(A) Annual data for 2009 and prior years is presented in accordance with Previous GAAP.

(B) During the second quarter of 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities Income and Expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Annual data for 2010 has been reclassified for comparability with current presentation.

(C) Net earnings adjusted for after-tax interest expense and after-tax foreign exchange loss (gain) on U.S. denominated long-term debt 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, on a weighted-average basis. For a detailed annual reconciliation of this measure see the Non-GAAP Financial Measures Advisory section of Suncor's 2011 Management Discussion & Analysis.

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

(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.

ANNUAL OPERATING SUMMARY[A]

(unaudited)

Oil Sands	2011	2010	2009	2008	2007
Production (mbbls/d)					
Total production (excluding Syncrude)	**304.7**	283.0	290.6	228.0	235.6
Firebag (mbbls/d of bitumen)	**59.5**	53.6	49.1	37.4	36.9
MacKay River (mbbls/d of bitumen)	**30.0**	31.5	12.4	—	—
Syncrude	**34.6**	35.2	16.1	—	—
Sales (mbbls/d) (excluding Syncrude)					
Light sweet crude oil	**85.5**	82.3	99.6	77.0	101.7
Diesel	**24.3**	20.4	29.1	19.8	25.0
Light sour crude oil	**170.6**	145.2	135.7	128.7	102.3
Bitumen	**24.0**	31.4	11.8	1.5	5.7
	304.4	279.3	276.2	227.0	234.7
Average sales price[1] **(excluding Syncrude)** (dollars per barrel)					
Light sweet crude oil *	**98.50**	79.03	67.26	98.66	78.03
Other (diesel, light sour crude oil and bitumen) *	**84.93**	68.63	64.18	95.14	70.86
Total *	**88.74**	71.69	65.29	96.33	74.07
Total	**88.74**	69.58	61.66	95.96	74.01
Syncrude average sales price[1] (dollars per barrel)	**101.80**	80.93	77.36	—	—
Operating costs (excluding Syncrude) (dollars per barrel)					
Cash operating costs[2]	**40.20**	38.65	33.95	38.50	27.80
Total cash operating costs[3]	**41.65**	39.35	34.40	38.90	28.75
Total operating costs[4]	**52.20**	50.50	42.40	45.85	34.15
Operating costs – Syncrude*** (dollars per barrel)					
Cash operating costs[2]	**42.15**	37.95	32.50	—	—
Total cash operating costs[3]	**42.15**	37.95	32.50	—	—
Total operating costs[4]	**57.75**	50.95	44.65	—	—
Operating costs – In situ bitumen production only (dollars per barrel)					
Cash operating costs[5]	**25.70**	20.40	20.25	25.30	20.75
Total cash operating costs[6]	**29.60**	22.45	21.60	25.95	20.75
Total operating costs[7]	**36.95**	27.75	27.95	32.30	26.95

(A) Annual data for 2009 and prior years is presented in accordance with Previous GAAP.

Footnotes and definitions, see page 136.

ANNUAL OPERATING SUMMARY (continued)

(unaudited)

Exploration and Production	**2011**	2010	2009	2008	2007
Total Production (mboe/d)	**206.7**	296.9	149.3	36.7	35.8
North America Onshore					
Production					
Natural gas (mmcf/d)	**357**	522	397	202	196
Natural gas liquids and crude oil (mbbls/d)	**5.1**	8.8	8.1	3.1	3.1
Total production (mmcfe/d)	**388**	575	446	220	215
Average sales price [1]					
Natural gas (dollars per mcf)	**3.55**	4.04	4.10	8.23	6.32
Natural gas (dollars per mcf) *	**3.55**	4.04	4.08	8.25	6.27
Natural gas liquids and crude oil (dollars per barrel)	**85.30**	67.06	56.84	70.89	56.64
East Coast Canada					
Production (mbbls/d)					
Terra Nova	**16.2**	23.2	8.7	–	–
Hibernia	**30.9**	30.9	11.4	–	–
White Rose	**18.5**	14.5	4.2	–	–
	65.6	68.6	24.3	–	–
Average sales price [1] (dollars per barrel)	**108.42**	80.20	76.86	–	–
International					
Production (mboe/d)					
North Sea					
Buzzard	**42.9**	55.5	20.0	–	–
Other North Sea	**3.8**	23.5	12.0	–	–
Other International					
Libya	**12.1**	35.2	13.7	–	–
Syria	**17.6**	11.6	–	–	–
Trinidad and Tobago	**–**	6.7	4.9	–	–
	76.4	132.5	50.6	–	–
Average sales price [1] (dollars per boe)				–	–
Buzzard	**105.18**	77.91	69.53	–	–
Other North Sea	**92.49**	78.16	73.52	–	–
Other International	**95.76**	70.39	61.25	–	–

Footnotes and definitions, see page 136.

ANNUAL OPERATING SUMMARY (continued)

(unaudited)

Refining and Marketing	**2011**	2010	2009	2008	2007
Eastern North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**20.9**	22.2	14.6	7.9	8.8
Distillate	**12.8**	12.4	8.8	5.2	5.4
Total transportation fuel sales	**33.7**	34.6	23.4	13.1	14.2
Petrochemicals	**2.1**	2.5	0.8	0.8	0.9
Asphalt	**2.4**	2.7	1.5	0.6	0.3
Other	**5.3**	5.5	2.0	1.0	2.2
Total refined product sales	**43.5**	45.3	27.7	15.5	17.6
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**32.0**	30.5	29.6*****	11.0	10.9
Utilization of refining capacity (%)	**94**	89	87	99	98
Western North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**18.8**	18.9	13.0	8.0	8.0
Distillate****	**17.6**	18.0	9.5	5.6	5.2
Total transportation fuel sales	**36.4**	36.9	22.5	13.6	13.2
Asphalt	**1.2**	1.3	1.3	1.2	1.4
Other	**2.0**	3.8	3.4	1.2	1.3
Total refined product sales	**39.6**	42.0	27.2	16.0	15.9
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**32.8**	34.6	33.6*****	13.7	14.2
Utilization of refining capacity (%)	**91**	95	97	96	99
Retail outlets	**1 732**	1 723	1 813	427	419

Footnotes and definitions, see page 136.

OPERATING SUMMARY INFORMATION

(unaudited)

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 diluent and imported bitumen. 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.

** Cash operating costs include the cost of purchased diluent required to facilitate the delivery of bitumen via pipeline. Under normal operating conditions diluent requirements are satisfied with internal production.

*** Users are cautioned that the Syncrude cash 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 operating and capital costs among producers.

**** Previously disclosed distillate sales volumes have been adjusted to remove certain sales volumes that originated in the Oil Sands segment.

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

Abbreviations

mbbls/d	—	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
mboe/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

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 2011	**June 30 2011**	**Sept 30 2011**	**Dec 31 2011**	Mar 31 2010	June 30 2010	Sept 30 2010	Dec 31 2010
Share ownership								
Average number outstanding, weighted monthly (1) (thousands)	**1 570 283**	**1 573 537**	**1 572 970**	**1 566 154**	1 560 744	1 561 650	1 562 538	1 564 170
Share price (dollars)								
Toronto Stock Exchange								
High	**47.27**	**44.78**	**40.70**	**33.75**	39.45	35.82	34.94	38.56
Low	**36.31**	**36.31**	**25.61**	**23.97**	29.93	29.91	30.72	32.25
Close	**43.48**	**37.80**	**26.76**	**29.38**	33.03	31.33	33.50	38.28
New York Stock Exchange – US$								
High	**48.53**	**47.00**	**41.88**	**33.40**	38.22	35.71	34.17	0.82
Low	**36.54**	**36.93**	**24.94**	**22.55**	28.04	27.65	28.56	31.53
Close	**44.84**	**39.10**	**25.44**	**28.83**	32.54	29.44	32.55	38.29
Shares traded (thousands)								
Toronto Stock Exchange	**314 473**	**265 385**	**348 646**	**333 369**	293 414	334 463	237 687	241 413
New York Stock Exchange	**499 443**	**402 729**	**500 005**	**446 312**	503 927	582 189	302 054	374 370
Per common share information (dollars)								
Net earnings – basic	**0.65**	**0.36**	**0.82**	**0.91**	0.46	0.31	0.65	0.87
Dividend	**0.10**	**0.11**	**0.11**	**0.11**	0.10	0.10	0.10	0.10

(1) The company had approximately 4,415 holders of record of common shares as at January 31, 2012.

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.

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