UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER
Pursuant to Section 13a-16 or 15d-16 of the
Securities Exchange Act of 1934

March, 2011

Commission File Number: 333-12138

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of registrant as specified in its charter)

2500, 855 – 2nd Street S.W., Calgary, Alberta, Canada T2P 4J8
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F ___ Form 40-F X

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). ____

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ___ No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-______

The Annual Report attached hereto as Exhibit 99.1, limited to those portions beginning with the heading "Management's Discussion and Analysis" on page 23 and including "Financial Statements" through to page 93 inclusive, is incorporated by reference into the Registration Statement on Form F-9 (File No. 333-162270) as an exhibit thereto:

Exhibit Number	Description
99.1	Annual Report issued by Canadian Natural Resources Limited to its shareholders referenced as 2010 Annual Report.

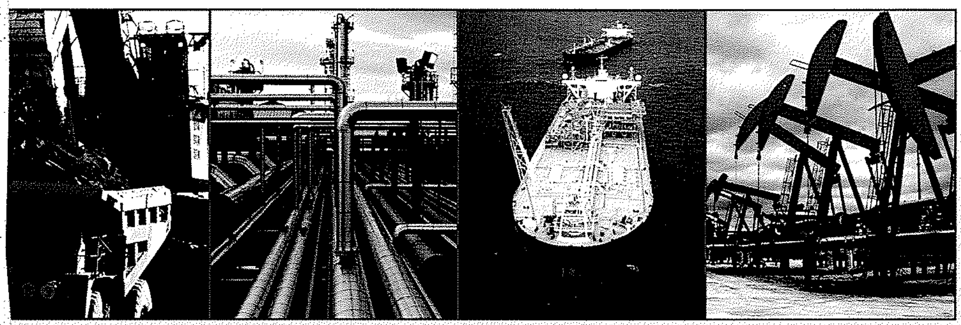
SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CANADIAN NATURAL RESOURCES LIMITED
(Registrant)

Date: April 11, 2011

By: ______________________
Bruce E. McGrath
Corporate Secretary



Canadian Natural

ANNUAL REPORT 2010

The Premium Value

Defined Growth

Independent

Value Creation

CANADIAN NATURAL'S STRONG ASSET BASE PROVIDES MANY OPPORTUNITIES TO ADD SHAREHOLDER VALUE. WHETHER THROUGH THE DRILL-BIT OR THROUGH ACQUISITIONS WE WILL CONTINUE TO ADD VALUE GROWTH USING A RESPONSIBLE ALLOCATION OF CAPITAL TO PROJECTS WITH THE HIGHEST RETURNS.

WE CONTINUE TO PREPARE THE COMPANY FOR FLUCTUATIONS IN MARKET CONDITIONS SO THAT WHEN CHANGES DO OCCUR WE ARE PREPARED TO CAPITALIZE. WE ARE CONFIDENT THAT WITH OUR ASSET BASE AND A DISCIPLINED ALLOCATION OF CAPITAL WE WILL CREATE VALUE AND DELIVER ON OUR PROJECTS IN THE SHORT-, MID- AND LONG-TERM.

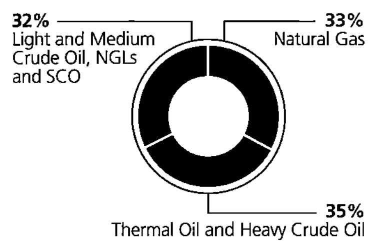
Balance

A main driver of our strength is our balanced portfolio and the ability to allocate capital to the highest return projects. With a balanced asset base we are better equipped to withstand commodity price cycles and strengthen the Company's position.

Our balance lies, not only in our physical assets such as Natural Gas, Light and Medium Crude Oil, NGLs, Primary Heavy Crude Oil, Pelican Lake Heavy Crude Oil, Thermal Oil and Mining Synthetic Crude Oil ("SCO") but also in:

- **The geographic regions where we operate** – With core operations in Western Canada, the UK sector of the North Sea and Offshore West Africa, we have developed a strong technical background in both onshore and offshore operations.
- **The timeline of our projects** – With our vast asset base, Canadian Natural has evolved into a Company with short-, mid- and long-term projects that will provide decades of value growth.
- **The maintenance of a strong, balanced financial position** – Essential as it allows the Company to capitalize on opportunities.
- **The uses of cash flow** – As the Company generates significant free cash flow, a balanced approach to uses of cash has been established with the allocation of capital to value adding projects, debt repayment and dividends.

BALANCED PRODUCTION



376

NUMBER OF INTERNATIONAL EMPLOYEES

4,671

NUMBER OF EMPLOYEES WORLDWIDE

275

YEARS OF **CNQ** EXPERIENCE ON THE MANAGEMENT COMMITTEE

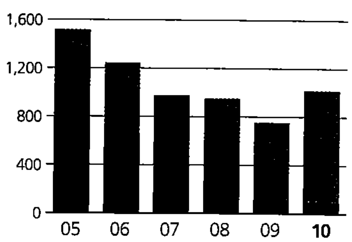
Discipline and Flexibility

Our disciplined approach in how we operate and allocate capital has been a driver in creating significant shareholder value for more than twenty years.

Dedication to our principles is evident in our approach to business decisions across the Company. Our disciplined approach provides the flexibility to shift capital to the highest return projects as demonstrated by:

- **Value Growth and Production Growth** – We make decisions to allocate capital to projects that generate the best returns, not necessarily the largest production growth.
- **Opportunistic Acquisitions** – Acquisitions must compete for capital. Our commitment to value adding projects ensures acquisitions we execute create shareholder value.
- **Balanced Asset Base** – Our balanced asset base provides opportunities in different commodity price environments. In 2010, our focus was on crude oil development as we await the recovery in natural gas prices.
- **Own and Operate our Production** – We strive to own and operate 100 percent of our production. We do this by dominating the land base and infrastructure in our core areas. This provides the best opportunity to maintain effective operations, determine project timing and drive the process of capital allocation.

SUCCESSFUL NATURAL GAS AND CRUDE OIL NET WELLS DRILLED



■ Crude Oil Wells
■ Natural Gas Wells

Operational and Financial Strength

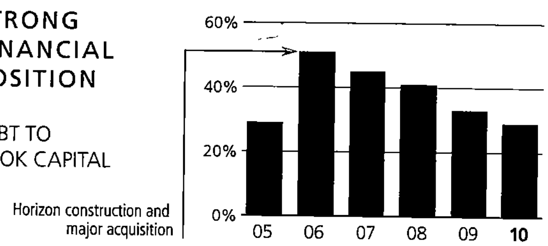
Canadian Natural employees strive to be the most safe, efficient and effective operators in the areas we do business. We strive to integrate economic, environmental and social considerations in our decision making process.

We continue to build a world class crude oil and natural gas company and at the same time continue to build our financial, operational, technical and managerial strengths through:

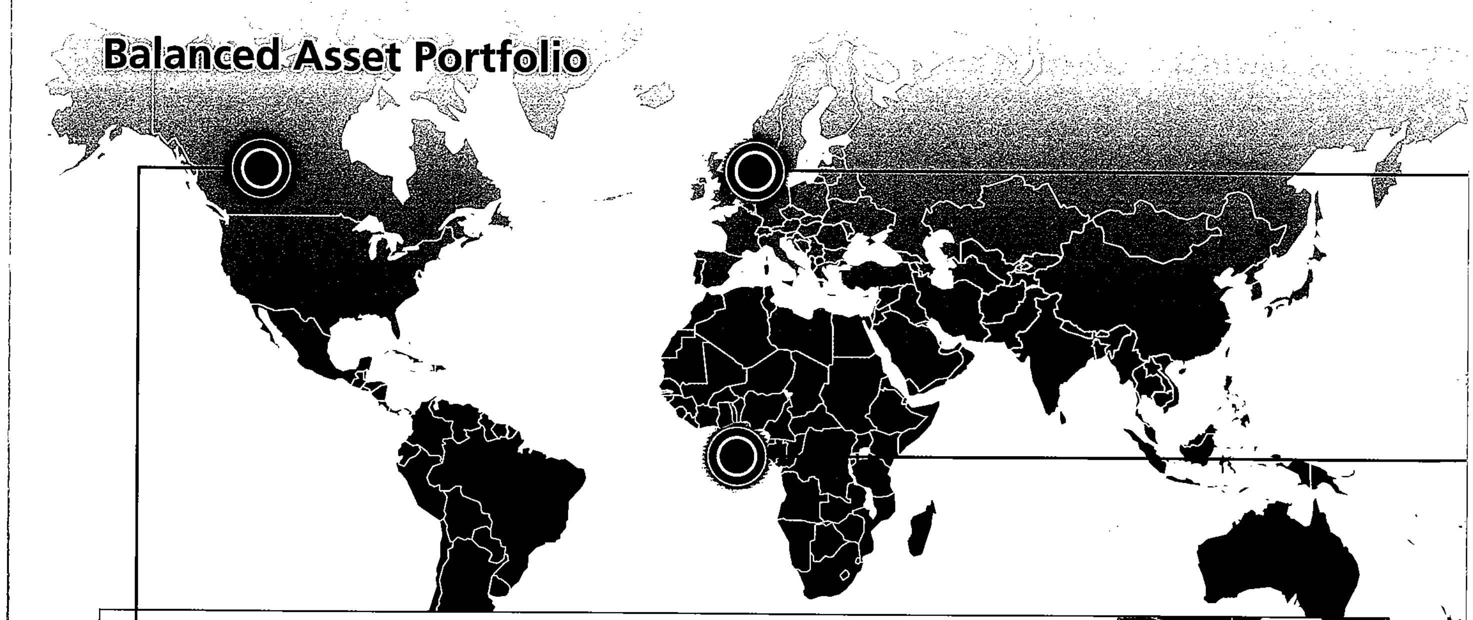
- **A Strong Balance Sheet with Investment Grade Debt Ratings** – Allows us to take advantage of value adding opportunities that may present themselves in varying economic cycles.
- **Technical and Operational Skills** – A wide array of technical and operational skills exists in the Company that range from heavy crude oil, unconventional natural gas, thermal in situ, oil sands mining, enhanced oil recovery techniques, as well as offshore deep water.
- **Proven Management Team** – A strong track record of creating value with a winning strategy and a well defined plan.
- **Efficient and Effective Operations** – Incorporating a focus on safety and minimal environmental impact which ultimately leads to cost-controlled operations.

STRONG FINANCIAL POSITION

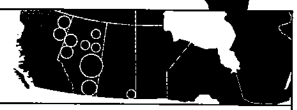
DEBT TO BOOK CAPITAL



Balanced Asset Portfolio



North America Crude Oil



THERMAL OIL

Our extensive high quality thermal oil asset base will deliver significant growth over the next decade. A defined plan is in place targeting to add incremental production capacity of 30,000 to 60,000 bbl/d every two to three years. A total of 445,000 bbl/d of thermal oil production capacity is targeted in the defined plan.

- WELL DEFINED GROWTH PLAN
- TARGET 445,000 BBL/D OF PRODUCTION CAPACITY
- 34.5 BILLION BARRELS OF BITUMEN INITIALLY IN PLACE (1)

PELICAN LAKE HEAVY CRUDE OIL

A world class oil pool that is creating significant shareholder value through an enhanced crude oil recovery technique known as polymer flooding. We continue to invest in the polymer flood and target to increase production to 80,000 bbl/d. The use of the polymer flood adds value through increased production, higher recovery factors and increased reserves.

- TARGET 80,000 BBL/D OF PRODUCTION
- 4.1 BILLION BARRELS OF HEAVY CRUDE OIL INITIALLY IN PLACE (2)
- WORLD CLASS CRUDE OIL POOL

PRIMARY HEAVY CRUDE OIL

We target annual production growth in primary heavy crude oil of 10% over the next three years. Due to our dominant land base in the area and because we own and operate much of the infrastructure, we are able to execute on significant drilling programs while maintaining efficient operations. These assets provide quick payouts, high returns and compliment some of our longer lead projects.

- 2010 RECORD DRILLING PROGRAM
- 9,000 POTENTIAL DRILLING LOCATIONS
- LOW CAPITAL AND OPERATING COSTS

LIGHT AND MEDIUM CRUDE OIL

Light and medium crude oil in Canada provides product balance to our portfolio and opportunities to implement our strong exploitation skill set. We continue to add value and growth in this part of the business while continuing to invest in enhanced oil recovery techniques and technology that will provide long-term value enhancement.

- BALANCES PORTFOLIO
- EFFICIENT AND EFFECTIVE OPERATIONS
- USE OF ENHANCED RECOVERY TECHNIQUES

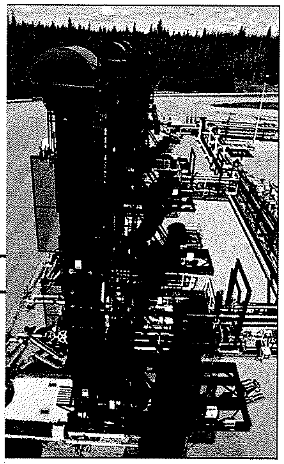
HORIZON OIL SANDS

Completion of Phase 1 of Horizon Oil Sands ("Horizon") mining operations was a key accomplishment for the Company. Production of 34° API SCO at 110,000 bbl/d balances our asset portfolio and enables us to diversify and strengthen our technical and operating skills. Operational optimization and expansion preparation remain our focus. We target to maintain sustainable production rates and exercise control with our expansion capital program.

- 14.3 BILLION BARRELS OF BITUMEN INITIALLY IN PLACE (3)
- WORLD CLASS ASSET
- PLANNED EXPANSION UP TO 250,000 BBL/D

(1)(2)(3) Please refer to page 16 for further resource disclosure.

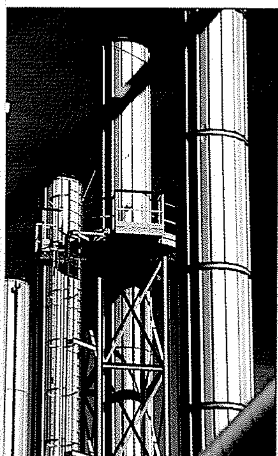
Investment Strategy



Capital spending to cash flow generation

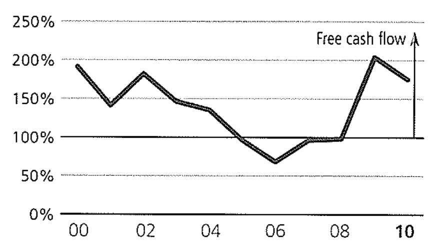
Canadian Natural is entering the next stage of evolution where prior capital spending begins to turn into significant free cash flow generation. At the same time the Company maintains a vast number of projects that will provide value growth for decades.

Our diverse, balanced asset base allows us to choose projects that will provide the best returns in ever changing commodity price environments and our strong technical, operational, financial and managerial skills gives us the best opportunity to execute these projects.



CASH FLOW AS PERCENTAGE OF CAPITAL

Capital excludes acquisitions

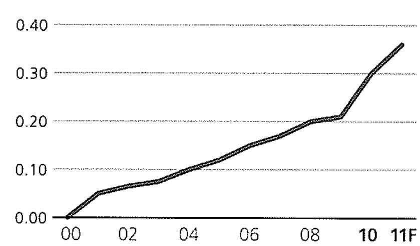


STRONG CASH FLOW GENERATION ENABLES THE NEXT LEG OF GROWTH

SOLID FINANCIAL POSITION ALLOWS THE COMPANY TO CAPTURE VALUE ADDED OPPORTUNITIES

DIVIDEND GROWTH HISTORY

(CANADIAN DOLLARS)



ELEVEN CONSECUTIVE YEARS OF DIVIDEND INCREASES

43% DIVIDEND INCREASE IN 2010, A FURTHER 20% INCREASE IN 2011

Strategic discipline

A disciplined, low risk approach to growing the Company has and will continue to provide shareholder value.

- Dominate our core areas;
- Focus on value growth;
- Most efficient and effective operator in our core areas;
- Maintain a strong balance sheet;
- Short-, mid- and long-term projects in our portfolio;
- Free cash flow generation;
- Disciplined allocation of capital; and
- Return to shareholders.

THE INVESTMENT STRATEGY REMAINS THE SAME – MAINTAIN A STRONG BALANCE SHEET AND A BALANCED PORTFOLIO OF ASSETS WHICH DRIVES THE ABILITY TO ALLOCATE CAPITAL TO THE HIGHEST RETURN PROJECTS REGARDLESS OF THE COMMODITY PRICE CYCLE.

Drivers of Future Growth

Thermal oil growth plan

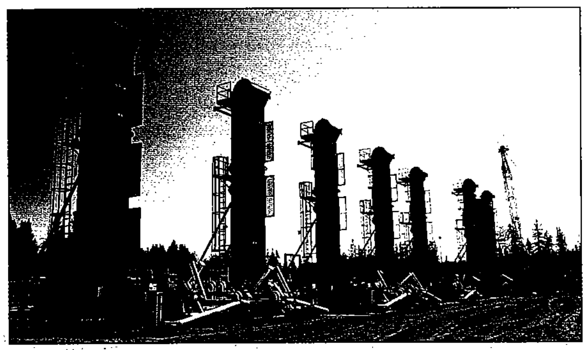
Thermal oil is one of the main drivers of future growth for the Company. We have a large, high quality land base in the Cold Lake and Athabasca regions of the oil sands in Alberta. We target to grow production capacity from the current 120,000 to 445,000 bbl/d by 2024.

	Thermal Oil Facility Target Steam-In		
Phase	**Reservoir**	**Capacity (bbl/d)**	**Timing (year)**
Primrose South/North - CSS	Clearwater	80,000	On Stream
Primrose East - CSS	Clearwater	40,000	On Stream
Kirby Phase 1 - SAGD	McMurray	40,000	2013
Kirby Phase 2 - SAGD	McMurray	30,000 to 60,000	2016
Grouse - SAGD	McMurray	60,000	2018
Birch Mountain Phase 1 - SAGD	McMurray	60,000	2020
Birch Mountain Phase 2 - SAGD	McMurray	60,000	2022
Gregoire Phase 1 - SAGD	McMurray	60,000	2024

445,000 bbl/d of thermal oil facility capacity in the defined growth plan.

30,000 to 60,000 bbl/d addition every 2 to 3 years.

- Systematic approach to developing the assets that will provide value through capital efficiencies.
- Technological experience in Cyclic Steam Stimulation ("CSS") and Steam Assisted Gravity Drainage ("SAGD") through current production.
- Continued focus on effective and efficient operations through safe operations with minimal environmental footprint and cost control.
- Manageable increments allows for better execution.



42%
2010 THERMAL OIL PRODUCTION GROWTH

>98%
WATER RECYCLED AT PRIMROSE

120,000
CURRENT THERMAL OIL PRODUCTION CAPACITY (bbl/d)

Preparation

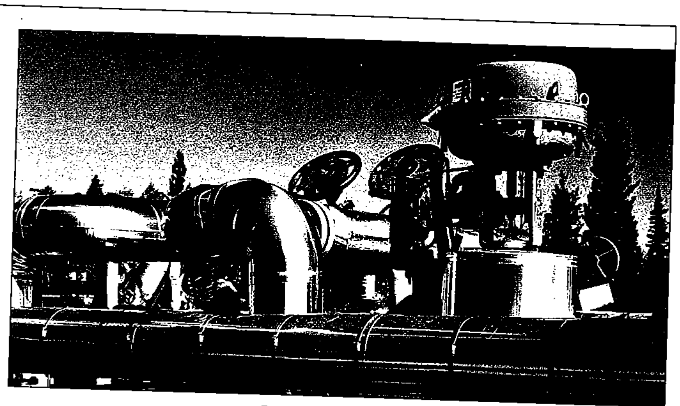
SOLID EXECUTION IS HIGHLY DEPENDENT ON PREPARATION WORK WHICH ENSURES CAPITAL IS SPENT EFFICIENTLY. AT CANADIAN NATURAL WE MAKE EVERY EFFORT TO ENSURE WE ARE PREPARED FOR THE SHORT-, MID- AND LONG-TERM. A GOOD EXAMPLE IS IN THE OIL SANDS WHERE NOT ALL LEASES AND RESERVOIRS ARE CREATED EQUAL. IT IS ESSENTIAL TO UNDERSTAND THE SUB SURFACE IN ORDER TO ENSURE THE BEST EXECUTION.

Thermal Oil

Not all oil sands are created equal and we know the importance of understanding the reservoir to ensure wells are placed correctly. We drill many stratigraphic wells to ensure we delineate the reservoir and build the project in the most efficient manner possible.

Kirby In situ Oil Sands ("Kirby") is the next thermal oil sands project on the list of projects we target to complete over the next decade. Kirby Phase 1 will add 40,000 bbl/d of production capacity with first steam targeted for the end of 2013.

Additional preparation for Kirby Phase 1 included a pilot project to ensure we were prepared before proceeding with the 40,000 bbl/d capacity project.



SUCCESSFUL SAGD AND CSS OPERATIONS

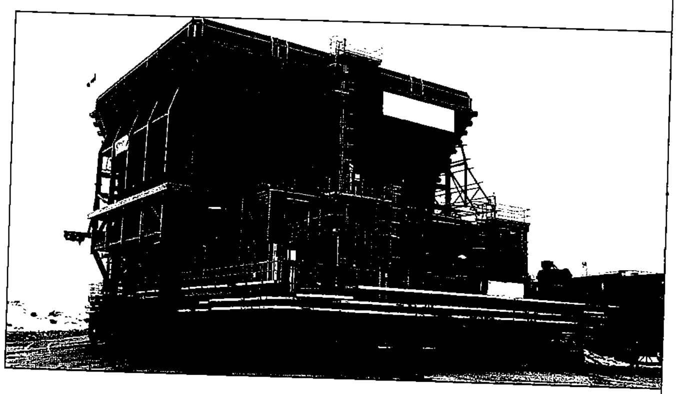
HIGH DEGREE OF UP FRONT ENGINEERING

172 STRAT WELLS FOR RESERVOIR DELINEATION

Horizon Oil Sands

While building Phase 1 we gained valuable experience and have compiled lessons learned which we will apply to future development. Some execution strategies we did well and we have identified improvements to other strategies, as well as new strategies to improve performance going forward. This will increase the cost certainty of future developments and will help us capture the highest return on capital possible.

Future developments at Horizon will be broken into smaller projects. These projects are easier to manage and provide the opportunity for the best execution. We target to limit yearly spending at Horizon to between $2.0 billion and $2.5 billion with fewer than 5,500 construction workers on site. Our lessons learned from Phase 1 have provided us the groundwork for future development.



FLEXIBLE PLAN

HIGH DEGREE OF UP FRONT ENGINEERING

INFRASTRUCTURE FOR FUTURE DEVELOPMENT ALREADY IN PLACE

2010

JAN FEB MAR APR MAY

JANUARY – COMMENCED RECORD HEAVY CRUDE OIL DRILLING PROGRAM

MARCH – 43% INCREASE IN DIVIDEND

APRIL – CLOSED SEVERAL TRANSACTIONS TO PURCHASE CRUDE OIL AND NATURAL GAS PROPERTIES IN WESTERN CANADA

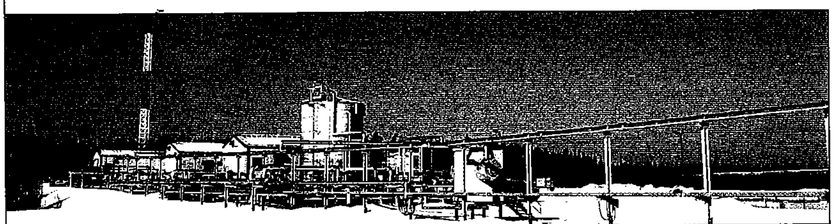
MAY – SHAREHOLDER

Execution

The Future

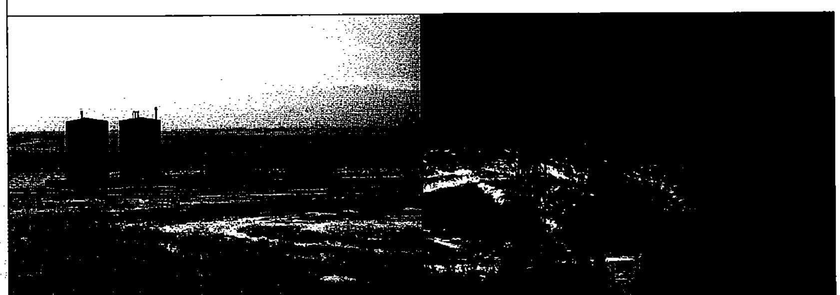
PELICAN LAKE

Pelican Lake is a good example of how implementing technological advancements provides value. Pelican Lake was originally developed using primary recovery techniques, which only yielded about 5% recovery. Waterflooding increased recovery to around 10% of the crude oil initially in place, still leaving behind a vast amount of crude oil. Using our exploitation expertise we discovered the pool was amenable to polymer flooding which could yield over 20% recovery in the best parts of the pool. We ultimately target to have close to 90% of the pool under polymer flood and target production to reach 80,000 bbl/d. We currently have 44% of the pool under polymer flood and have been able to execute and operate this program in an efficient manner by implementing optimization practices and exploiting capital efficiencies.



ORGANIC GROWTH AND STRATEGIC ACQUISITIONS

The Company has deliberately built a well balanced asset base, both organically and through acquisitions. This asset base will provide decades of future growth for the Company as we execute on our defined plan. Additionally, we will continue to opportunistically add, if value adding opportunities exist, to our asset base to provide immediate value and future upside no differently than what we executed in 2010 that provides us with a stronger natural gas foot print and upside in our thermal operations.



THERMAL OIL

We have a proven track record of executing thermal projects and will use those experiences to drive our defined plan forward.

- Successfully ramped up production from 40,000 to 120,000 bbl/d in cost effective steps over the last 8 years.
- Executed successful acquisitions which provide the land base for significant potential upside.
- Technical expertise demonstrated through adaptability of steaming techniques.

HORIZON OIL SANDS

We gained valuable experience in building and operating Phase 1 of Horizon which we will leverage in executing debottlenecking and expansions as we move to develop this world class asset.

- Assembling and maintaining a strong team with technical, financial and managerial expertise is fundamental in successful project execution.
- Being execution focused rather than schedule driven supports flexible decision making.
- Debottlenecking opportunities provide smaller incremental production adds, but allow for successful execution.

JUN JUL AUG SEP OCT NOV DEC

OLDER APPROVAL OF 2 FOR 1 SHARE SPLIT

JUNE – ACHIEVED RECORD MONTHLY PRODUCTION RATES
– HORIZON – OVER 117,000 BBL/D (SCO)
– THERMAL – OVER 116,000 BBL/D (BITUMEN)

OCTOBER – PURCHASED ADDITIONAL LEASES ADJACENT TO KIRBY PHASE 1 LEASES

NOVEMBER – BOARD SANCTION FOR KIRBY PHASE 1 THERMAL PROJECT

DECEMBER – ANNOUNCED EXPANSION STRATEGY AT HORIZON OIL SANDS
– START-UP OF SEPTIMUS MONTNEY SHALE GAS PROJECT

OUR LARGE BALANCED ASSET BASE PROVIDES SUBSTANTIAL OPPORTUNITIES TO APPLY OUR EXPERTISE AS A LOW RISK EXPLOITATION FOCUSED OPERATOR. WE CONTINUE TO OPTIMIZE CURRENT INDUSTRY TECHNIQUES AS WELL AS LOOK TO IMPROVE OUR SKILL SET THROUGH TECHNOLOGICAL ADVANCEMENTS. AS A RESULT OF THE LARGE LAND POSITION WE HAVE BUILT, WE CONTINUE TO BENEFIT FROM IMPROVED TECHNIQUES AND NEW TECHNOLOGIES FOR RECOVERING CRUDE OIL AND NATURAL GAS IN BOTH NEW AND MATURE POOLS.

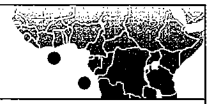
North Sea

Our North Sea operations provide the Company with significant free cash flow and a product balance with high quality light crude oil. Opportunities remain in the North Sea to optimize waterfloods and operating costs.

Low risk development opportunities exist with infill and step out drilling. We have been able to leverage our expertise in the North Sea to our other offshore assets.

- SIGNIFICANT FREE CASH FLOW
- EXPLOITATION OPPORTUNITIES
- OFFSHORE DRILLING EXPERTISE

Offshore West Africa

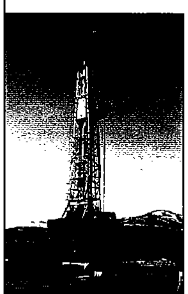


Offshore West Africa further balances our portfolio with light crude oil and provides significant free cash flow to the Company.

We operate the production with a high working interest and continue to gain valuable experience in Floating Production Storage and Offloading vessel operations. The area provides a sizeable resource with opportunities for future exploitation.

- SIGNIFICANT FREE CASH FLOW
- OPTIMIZE OPERATIONS
- OFFSHORE DRILLING EXPERTISE

North America Natural Gas

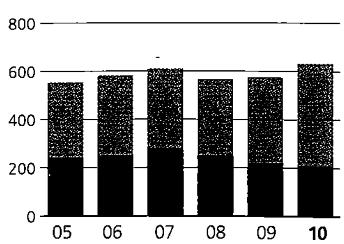


We are one of the largest producers of natural gas in Canada and have amassed an asset base capable of 5% per annum production growth in the right pricing environment. Our dedication to responsible allocation of capital is evident in our decision to curtail current natural gas drilling opportunities and prepare our asset base for the eventual recovery in natural gas pricing. Our natural gas assets provide us exposure to various play-types adding to the diversity of our portfolio.

- SIGNIFICANT LAND POSITION
- LARGE UNCONVENTIONAL EXPOSURE
- HIGH LEVEL OF OPERATORSHIP
- 8,000 POTENTIAL DRILLING LOCATIONS

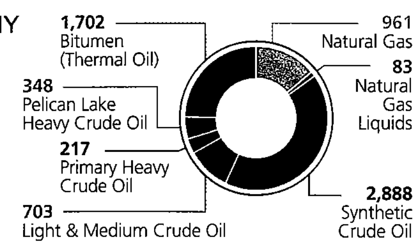
TOTAL PRODUCTION BEFORE ROYALTIES
(THOUSANDS OF BOE/D)

Crude Oil and NGLs
Natural Gas



TOTAL COMPANY GROSS PROVED PLUS PROBABLE RESERVES*
(MMBOE)

*As at Dec. 31, 2010 based on forecast prices and costs.



2010 Performance Highlights

	2010	2009 (1)	2008 (1)
FINANCIAL ($ millions, except per share data)			
Revenue, before royalties	**$ 14,322**	$ 11,078	$ 16,173
Net earnings	**$ 1,697**	$ 1,580	$ 4,985
Per common share – basic and diluted	**$ 1.56**	$ 1.46	$ 4.61
Adjusted net earnings from operations (2)	**$ 2,570**	$ 2,689	$ 3,492
Per common share – basic and diluted	**$ 2.36**	$ 2.48	$ 3.23
Cash flow from operations (3)	**$ 6,321**	$ 6,090	$ 6,969
Per common share – basic and diluted	**$ 5.81**	$ 5.62	$ 6.45
Capital expenditures, net of dispositions	**$ 5,506**	$ 2,997	$ 7,451
Long-term debt (4)	**$ 8,499**	$ 9,658	$ 13,016
Shareholders' equity	**$ 20,985**	$ 19,426	$ 18,374
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (Mbbl/d)			
North America – excluding Oil Sands Mining and Upgrading	**271**	234	244
North America – Oil Sands Mining and Upgrading	**91**	50	–
North Sea	**33**	38	45
Offshore West Africa	**30**	33	27
	425	355	316
Natural gas (MMcf/d)			
North America	**1,217**	1,287	1,472
North Sea	**10**	10	10
Offshore West Africa	**16**	18	13
	1,243	1,315	1,495
Barrels of oil equivalent (MBOE/d)	**632**	575	565

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.
(2) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").
(3) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the MD&A.
(4) Includes the current portion of long-term debt.

Drilling activity (net wells) [1]	**2010**	2009	2008
North America	**1,051**	793	984
North Sea	**1**	1	3
Offshore West Africa	**7**	5	3
	1,059	799	990
Core unproved property (thousands of net acres) [2]			
North America	**12,594**	N/A	N/A
North Sea	**128**	N/A	N/A
Offshore West Africa	**4,193**	N/A	N/A
	16,915		
Company gross proved reserves [3]			
Crude oil and NGLs (MMbbl)			
North America	**3,423**	3,116	3,013
North Sea	**252**	265	256
Offshore West Africa	**120**	136	156
	3,795	3,517	3,425
Natural gas (Bcf)			
North America	**4,092**	3,731	4,077
North Sea	**78**	72	67
Offshore West Africa	**92**	99	107
	4,262	3,902	4,251
Barrels of oil equivalent (MMBOE)	**4,505**	4,167	4,134

(1) Excludes net stratigraphic test and service wells.
(2) Due to the conversion to NI 51-101 disclosure requirements for 2010, the Company is reporting "unproved property" which is property or part of a property to which no reserves have been specifically attributed. As a result of the change, 2009 and 2008 have been excluded as comparisons would not be meaningful.
(3) Year-end 2009 and 2010 proved plus probable reserves were prepared using forecast prices and costs. Prior to 2009, reserves were prepared using constant price and costs.

Dear Shareholders,

OUR YEAR IN REVIEW

IN 2010, WE DEMONSTRATED OUR FINANCIAL STRENGTH AND COMMITMENT TO EFFICIENT AND EFFECTIVE OPERATIONS. OUR 2010 BUDGET FORECASTED A CAPITAL PROGRAM THAT WAS 31% HIGHER THAN 2009 CAPITAL EXPENDITURES AS ECONOMIC STABILITY RETURNED TO THE CRUDE OIL MARKET. WE USED THIS INCREASE IN CAPITAL TO FOCUS OUR ATTENTION ON STRONGER RETURN PROJECTS AND TO STRENGTHEN OUR DIVERSE ASSET BASE. DURING THE YEAR, WE CONCENTRATED ON PROGRESSING OUR PRIMARY HEAVY CRUDE OIL DRILLING PROGRAM, THE CONTINUED DEVELOPMENT AT OUR PRIMROSE THERMAL OIL PROJECT AND THE SUCCESSFUL ROLL OUT OF OUR POLYMER FLOOD AT PELICAN LAKE.

As well, we continued to leverage technology in our large, mature light crude oil assets in Canada and advance subsequent thermal projects in our defined growth plan. Horizon expansion preparation also remained a focus as we moved closer toward sustainable production volumes nearing plant capacity. Additionally, we moved forward with developing the first phase of our Montney shale gas play at Septimus in Northeast British Columbia.

As a result of our increased capital program, overall production growth averaged 10% and entry to exit growth was 24%. We achieved 6.33 BOE per share of proved plus probable reserves and record yearly production of over 632,000 barrels of oil equivalent per day. Our cash flow increased by 4% from 2009 and most importantly, the Company generated significant free cash flow of approximately $2.7 billion, excluding property acquisitions.

In our 2010 budget we identified our top priorities for uses of free cash flow. Our first priority was debt repayment. In 2010 we reduced long-term debt by $1.2 billion which resulted in a debt to book capitalization of 29%. Secondly, we were prepared to allocate free cash flow to asset development opportunities, opportunistic acquisitions, and share buy backs. In 2010 we executed $1.9 billion of opportunistic acquisitions contiguous to our existing land base within Western Canada, enabling operating synergies and significant upside potential. Furthermore, the Company repurchased two million common shares under our Normal Course Issuer Bid which allowed us to reduce the amount of dilution within the outstanding share base. Our third priority for free cash flow use was dividends. In early 2010 our Board of Directors approved a 43% dividend increase, the tenth consecutive increase of the dividend distribution. A further increase of 20% in quarterly dividend payout was then approved in early 2011 demonstrating our Board of Directors' confidence in the Company's growth and sustainability.

In 2010 we clearly proved the strength and depth of our asset base. We took advantage of our balanced and diverse portfolio so we could allocate capital to projects with the highest returns. Moreover, our ability to generate free cash flow and follow through

ALLAN P. MARKIN
Chairman

N. MURRAY EDWARDS
Vice-Chairman

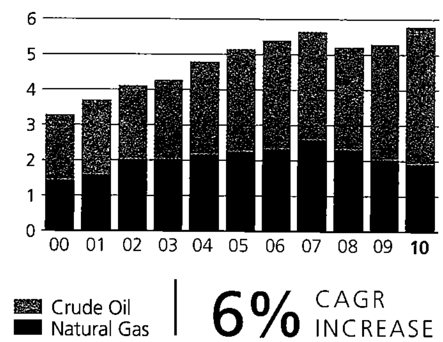
JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President

on our priorities for free cash flow usage reinforced the soundness of our strategy. We showed discipline and the ability of our asset base to deliver on our plans regardless of commodity price cycles.

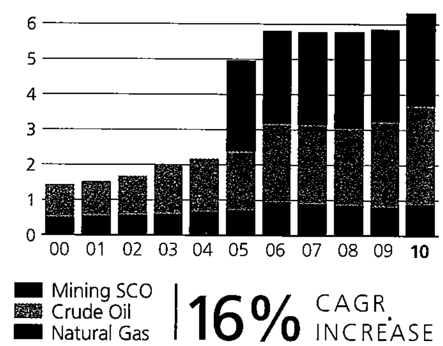
The challenges of 2010 such as low natural gas pricing and interrupted pipeline logistics are beyond the Company's control. But how we approach our business is within our control. Our strategy, which has not changed for over 20 years, continues to withstand changing commodity pricing and business environments. Over our history, we have built a portfolio of assets that provide us with diversity, balance and significant potential upside. Our people have strong operational, technical and financial experience. Our teams strive to operate as efficiently and effectively as possible through a focus on safety and minimal environmental impact which ultimately leads to cost controlled operations. The Company's disciplined approach towards operational and financial strength gives us the ability to maintain a strong balance sheet, generate significant free cash flow, and execute a flexible capital program. These strategic components continually direct our focus to returns on capital and our commitment to shareholder value.

DAILY PRODUCTION PER 10,000 SHARES (BOE/D)



6% CAGR INCREASE

GROSS RESERVES PER SHARE(1) (BOE)



16% CAGR INCREASE

North America Crude Oil and NGLs

Canadian Natural is one of the largest heavy crude oil producers in North America. We continue to grow this position as these assets provide us with strong returns and were allocated the majority of capital in 2010. We achieved 15% production growth over 2009 levels in North America crude oil and NGLs. Essential to this growth was our record drilling program of 654 net primary heavy crude oil wells where we grew production by 8%. Over the next 10 years, we can maintain this program as we have 9,000 net wells in our inventory illustrating that our primary heavy land base is one of the most robust in our portfolio. These assets provide us with quick cash on cash returns and generate significant value for the Company.

Along with completing a record primary heavy crude oil drilling program in 2010, we sanctioned Phase 1 of Kirby, the next step towards developing our long-term thermal growth plan that targets to add 445,000 barrels per day of thermal oil production capacity to our portfolio in the next 10 to 15 years. In the third and fourth quarters of 2010, the Company received regulatory approval and completed project sanction to move forward with Phase 1 of Kirby. Concurrent with this, the Company grew its land position by purchasing lands contiguous to existing leases. This acquisition bolsters our in situ potential and provides us significant upside to our portfolio and will allow Canadian Natural to capture capital and operating synergies at Kirby.

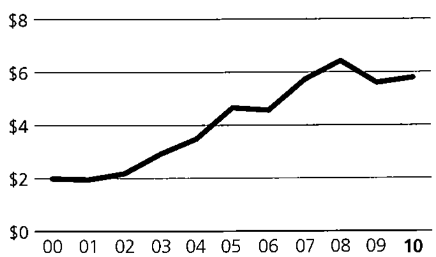
Our thermal operations delivered strong production in 2010. We produced over 90,000 barrels per day during the year and we target to grow production capacity to approximately 150,000 to 160,000 barrels per day by 2014 supported by Kirby Phase 1 production. Primrose East returned to normal operations and we have been able to rework our steaming cycles in order to optimize production volumes. For 2011, we target to grow thermal oil production by 12%. Stratigraphic drilling continues on future thermal leases to move us forward in a methodical manner as we target to add 30,000 to 60,000 barrels per day of bitumen every two to three years over the next 10 to 15 years.

Over our history, we have built a portfolio of assets that provide us with diversity, balance and significant potential upside.

At Pelican Lake, we now have 44% of the field converted to polymer flood and work progresses as we move towards flooding close to 90% of the field. We are still on the steep part of the learning curve in this area and anticipate polymer response to ramp up in 2011. Our growth at Pelican Lake will add meaningful value to the Company as we increase production capacity over the next four years to be between 78,000 and 82,000 barrels per day. This world class pool is targeted to achieve an exceptional 21% compound annual growth rate by 2014, further illustrating the depth of our asset portfolio.

(1) Please refer to page 16 for notes relating to graphs.

CASH FLOW
PER SHARE(2)



11% CAGR INCREASE

North America Natural Gas

We have strategically developed a land base that demonstrates our approach to efficient and effective operations. The Company has, over the years, created a dominant land position and controls most of the infrastructure within our core areas. As a result, we are able to capture operating and capital efficiencies, in all our activities whether they are organic or acquisitions. Today we produce 1.2 billion cubic feet per day of natural gas and we continue to be one of the largest natural gas producers in Western Canada. However in today's environment of low natural gas pricing, only some of our natural gas projects meet our internal hurdle rates for development. The oversupply in the natural gas market with shale production and the possibility of additional Liquid Natural Gas ("LNG") supply remain factors in the depressed pricing environment. As a result, we reduced our natural gas drilling program in 2010 to 92 wells and will reduce even further to 72 wells in 2011. This limited drilling program is only 8% of what our drilling activity was five years ago.

Although our outlook on natural gas pricing is currently unfavorable, we feel that the situation will reverse and it is a matter of time. We have seen the changes in commodity cycles throughout our plus 20 year history as a Company and we are confident that natural gas supply and demand will return to balance. We will prepare for the opportunity when natural gas projects become favorable again and have the assets to add value growth as the economics warrant investment. In 2010, we focused on strategic developments such as Septimus, a liquids rich Montney shale development in Northeast British Columbia. We believe the production and reserves of shale gas are real but we feel it is too early to tell whether there is longevity in the full cycle economics. We will continue to be selective in the development of this unconventional asset but will remain prudent in our approach. Additionally, we will high-grade current natural gas projects to ensure that we remain an efficient and effective operator. Unconventional and tight gas plays constitute approximately 60% of our natural gas drilling portfolio today and we aim to further strengthen this asset base adding further optionality. Finally, we will continue to delineate new and emerging plays and study new and existing technologies to ensure we unlock the value of our vast natural gas land base in the most efficient and effective manner.

International

In 2010, our international assets constituted 10% of total production, but generated over 20% of our total free cash flow. Not only do these assets provide us with significant free cash flow but they boost our light crude oil exposure. We leverage our offshore drilling expertise in the North Sea to our Offshore West Africa operations enabling us to gain additional experience in the international arena.

Canadian Natural's evolution will be anchored by a strong balance sheet and an ability to execute projects in the short-, mid- and long-term while maintaining a disciplined approach.

Our international assets give us the opportunity to leverage our technical and managerial strengths in optimizing operations. We operate the vast majority of our offshore assets and can utilize this expertise to optimize waterflood operations and identify new exploitation drilling opportunities. Our international assets are a core piece of the Company and have provided the free cash flow needed to fund Company growth initiatives. Although our latest development at Olowi in Gabon is below original expectations, we have taken steps to and will continue to look for opportunities to maximize the value of the project.

(2) (3) Please refer to page 16 for notes relating to graphs.

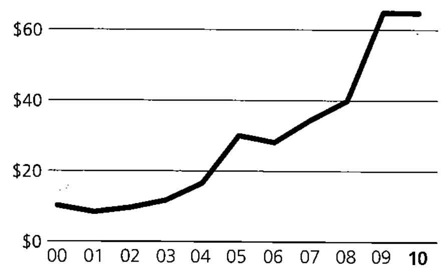
Horizon Oil Sands

Our ramp up in 2009 of SCO continued into 2010, during which we were able to fine-tune our winter operating procedures and preventative maintenance activities. At the same time, production volumes progressed to capacity levels. We are moving toward plant reliability and are targeting to implement additional reliability measures by the end of 2011.

In early 2011, a fire at the coker unit in primary upgrading has resulted in reduced 2011 production. We currently target to have half production capacity back on stream in Q2/11 and full production capacity in Q3/11. We target to fully understand how and why the incident occurred, and will immediately implement all changes or enhancements necessary to maintain the high level of safety and environmental excellence that is expected at all of our operations. Canadian Natural will leverage the learnings from this experience to become an even stronger operator.

Our preparation and planning for debottlenecking and expansions up to 250,000 barrels per day of SCO continues to make headway. With the experience of constructing Phase 1 under our belts, our "Lessons Learned" will guide how we will advance our expansions. We are extremely cognizant of controlling costs and will use our discipline to ensure that we move forward as efficiently as possible. The vast resource on our Horizon leases will provide significant value to shareholders and growth for the Company for decades.

PRETAX NET ASSET VALUE PER SHARE[3]



20% CAGR INCREASE

A Proven Strategy

From 2005 to 2010 the Company experienced many changing environments. However, we worked diligently to keep a disciplined approach and exercised responsible capital deployment. During the last few years the importance of having a balanced asset base and flexibility in capital spending was evident. These traits became extremely important at times as we were able to defer capital spending, focus on maintaining our asset base and remain focused on efficient and effective operations. In 2010, our core business generated over $2.7 billion of free cash flow which allowed us to make discretionary acquisitions of $1.9 billion while at the same time reducing debt by $1.2 billion, demonstrating the strength of our underlying assets. Production and cash flow grew 10% and 4% respectively from 2009 levels. Our ability to grow production and concurrently generate significant free cash flow puts us in a very unique position. Canadian Natural now has the ability to allocate capital to sizeable projects that do not necessarily provide immediate production such as our thermal assets, but provide long-term sustainable value growth. At the same time, due to our strong balance sheet and cash flow generating assets, we have the ability to fund expansions at Horizon and capture opportunistic acquisitions. We will persist in finding ways to increase our recovery rates in our dominant land bases such as heavy crude oil and light crude oil in North America. For 2011, we have dedicated significant capital to technological initiatives that will allow us to unlock significant value going forward.

Canadian Natural's evolution will be anchored by a strong balance sheet and an ability to execute projects in the short-, mid- and long-term while maintaining a disciplined approach. We remain committed to efficient and effective operations as this will be paramount to our success.

ALLAN P. MARKIN	N. MURRAY EDWARDS	JOHN G. LANGILLE	STEVE W. LAUT
Chairman	*Vice-Chairman*	*Vice-Chairman*	*President*

4,671 Strong: Diversity, Talent, Expertise

Duncan Aamot, Lonnie Abadier, John Abbott-Brown, Walday Abeda, Peter Abercrombie, Darren Acheson, Troy Adair, Denis Adam, Wade Adam, Belinda Adams, Mike Adams, Sean Adams, David Adamson, Debra Addinall, Adetokunbo Adebayo, Yemisi Adebayo, Adebukola Adegoroye, Abdinasir Aden, Richald Adzabe Ella, Setayesh Afshordi, James Agate, Anurag Agnihotri, Miguel Aguirre, Sarshar Ahmad, Pervez Ahmed, Salman Ahmed, Shakeel Ahmed, Dong Ai, Terry Aickelin, Richard Aikens, Garrison Ailsby, Travis Ailsby, Jason Airlie, Kristy Aitken, Jeffrey Akeroyd, Sina Akinsanya, Joseph Albano, David Albert, Jose Alcala, Suhaib AlDhabbi, Bruce Alexander, Joseph Alexander, Vincent Alexander, Walter Alexandru, Daniel Alfred, Elena Algazina, Mohieddin Alghazali, Arshad Ali, Haider Ali, Rachel Aliazas, John Allan, Jill Allen, John Allen, John Allen, Trent Allen, Simon Allerton, Devin Allibone, Karen Almadi, Jocelyn Alonso, Ali Al-Saleem, Khaled Alsouqi, Arturo Alvarez, Mathew Alves, Diane Amalaman, Gregory Amalia, Joann Aman, Traore Amara, Clark Ambler, Sharareh Ameripour, Donald Ames, Jan Andersen, Troy Andersen, Troy Andersen, Audrey Anderson, Diane Anderson, Georgina Anderson, Jeremy Anderson, Kelvin Anderson, Kristin Anderson, Leonard Anderson, Marilyn Anderson, Melissa Anderson, Perri Anderson, Sharon Anderson, Steve Anderson, Jadranka Andjelic, Peter Andrekson, Janet Andrew, Cole Andrews, Louise Andrews, Todd Andrews, Evan Angel, Carlo Angeles, Nathaelle Ango Mfene, Carolyn Angus, Muhammad Anis, Emma Annis, Stuart Annis, Greg Anstey, Helen Antle, Jamie Antle, Kathy Antonishyn, Shelley Antonuk, Prince Appiah, Brandon April, Richard April, Jose Araujo Zambrano, Luc Arbour, Murray Ardell, John Argan, Humberto Arias, Mirian Arias, Juan Arizaleta, James Arkley, Anthony Armstrong, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Shonn Arndt, Colin Arnold, Bruce Arscott, Monique Arsenault, Bala Arunachalam, Sudhakar Arunachalam, Arthur Ashley, Bonnie Ashley, Randy Aslin, Steven Aspden, Darrin Assinger, Jacqueline Asso, Victoire Assohou-Ouattara, Francklin Assoko-Mve, Andrew Astafos, John Atkinson, Edwin Au, Gordon Au, Sarah Aube, Dominick Aubut, Jason Auch, Bernard Auger, Richard Augustyn, Carlos Aular, Reinaldo Aular, Ryan Austin, Maria Avila, Carlos Aviles, Ward Ayles, Farooq Azam, Daniel

Babin, Krishnaswamy Babu, William Bachmeier, Adrian Baciulica, Angela Bacon, Iulian Badalan, Michael Baddeley, Vijay Bagde, Babak Baghban, Alex Bagnall, Mirka Baguela, Brian Bahlieda, Dave Baier, Janice Baik, Rod Bailer, Alex Bailey, Andrew Bailey, Brandon Bailey, Judy Bailey, Kimberley Bailey, Roysden Bailey, Leon Bakaas, Alysa Baker, Sharon Baker, Thomas Balakas, Charity Baldwin, Mark Baldwin, Robert Baldwin, Vaughn Baldwin, Irineo Balicanta, Joel Balkam, Darin Balkwill, Michael Ball, Gary Ballas, Ronnie Ballas, Sheldon Ballas, Brenda Balog, Ladji Bamba, Mamadou Bamba, Thomas Ban, Neville Banak, Saiyed Banamia, Darwin Banash, Junet Banawa, Mark Bancroft, Adam Banfield, Lance Banks, Linda Banks, Bennett Bannis, Teresa Banny, Cirilino Bantaya, Inge Bantli, Garry Bardoel, Larry Bardoel, Pamala Bare, Dale Barge, Muhammad Bari, Ross Barker, Sharon Barker, Andrew Barley, Dennis Barnes, Beata Barnett, Deborah Barr, Sean Barr, Eliezer Barreto, Robert Barten, Carrie Barter, Blair Bartlett, Cynthia Bartlett, Eddie Bartlett, Michael Bartlett, Catlin Bartman, Marty Bartman, Jose Basabe, Jason Basilan, Lloyd Basines, Michael Batac, Cheryl Bateman, Kevin Bateman, Lisa Bateman, Mark Batovanja, Brenda Battyanie, Jackie Bauer, Lydell Bauer, Ronnie Bauer, Jerry Bauman, Raymond Bazan, Brett Beach, Andrew Beacon, Colin Beaman, Harold Beamish, Chad Beaton, Aura Beattie, Randall Beatty, Erica Beauchamp, Alexandra Beaudoin, Joshua Beaudoin, Justin Beaudoin, Richard Beaudoin, Guy Beaulieu, Laurier Beaunoyer, Francis Beaver, Brent Beck, Chris Becker, Holly Becker, Bryce Beckner, Gurpreet Bedi, Keith Begg, Walter Behnke, Anhar Belah, Guy Belanger, Kelly Belanger, Lesley Belcourt, Andre Belisle, David Belisle, Calvin Bell, David Bell, Joey Bell, Jon Bell, Nicole Bell, Nigel Bell, Stephen Bell, Reg Bellanger, Matthew Beller, Janet Bembridge, Michael Bembridge, Ahmed Bendahmane, Khalida Bendahmane, Brad Bendick, Kim Benner, Chris Bennett, Erick Bennett, Jonathan Bennett, Murray Bennett, Robert Bennett, Brad Bensmiller, Shelly Bensmiller, Chad Benson, Linda Beresh, Debbie Berg, Kevin Bergen, Jeffrey Bergeson, David Berlinguette, Henry Berlinguette, Daniel Bernardo, Chris Bernath, Lynn Bernhardt, Joanne Berrade, Murray Bertsch, Jeffrey Best, Jonathon Best, Judy Best, Stewart Bettinson, Umeet Bhachu, Sanjeev Bharadwaj, Rupal Bhatt, Pareshkumar Bhavsar, Marc Bickham, Jennifer Bidlake Schroeder, Corey Bieber, Daniel Bieber, Douglas Bielech, Derek Biener, Inge Biener, Judy Billard-Payne, Roger Binkley, Roger Bintz, Warren Birch, John Bird, Katherine Bird, Robert Bischoff, Shane Bischoff, Christopher Bish, Kathy Bishop, Travis Bishop, Craig Bisschop, Alain Bissonnette, Darwin Bittner, Adam Black, Chad Black, Chad Black, Chris Black, David Black, Leah Black, Paul Blackburn, Kenneth Blackhall, Kerri Blackmore, Daniel Blain, Brittnee Blair, Deana Blais, David Blake, Barton Blakney, Alvaro Blanco, Ulises Blanco, William Blanco, Chris Blatchly, Shawn Blaydes, Zoe Bleackley, Juan Carlos Blesa, Parrish Blizard, Judith Blomdal, Rolland Blouin, Gregory Blundon, Carlos Boadas Salazar, Henry Bocalan, Allan Boddy, Rodney Bodell, Dennis Boehmer, Kent Boerrichter, Kyle Boerrichter, Dean Boettcher, Darcy Boettger, Warren Bogelund, Marty Boggust, Tyler Bohach, Juan Bohorquez, Gordon Bohrson, Lauren Boida, Claude Boily, Evan Boire, Jeannine Boire, Michael Boiianatz, Greg Bolin, Gregory Bolton, Shawn Bond, Ariadna Bonilla, Tom Bonwick, Patricia Booklall, Jim Boomgaarden, Charlene Boraas, Barry Borbely, Adriana Borbon, Joshua Borg, Robert Borg, Fernando Borjas, Mark Born, Michael Born, Jon Borstel, Blair Bosch, Dave Bosch, Keith Bottrell, Maurice Bouchard, Ronald Boucher, Suzanne Boudignon, Donald Boudreau, Lance Boulet, Tyler Bouma, Rick Bourassa, Sheldon Bourassa, Derek Bourgoin, Delwood Bourke, Daryl Bourque, Christine Boussougou Mayagui, Kyle Boutilier, Daniel Boutin, Devrey Bowen, Jonathan Bowen, Robert Bowers, Slade Bowers, Jason Bowie, Bruce Bowles, Clinton Bowles, Nadine Bowles, Ernest Bown, Eric Boy, Dale Boychuk, Doug Boyd, Patrick Boyd, Raymond Boyd, Shirley Boyd, Charline Boyer, David Boyko, Lorraine Boyle, Richard Boyle, Neil Bozak, John Brabec, Dave Bracey, Andrea Bradley, Bryan Bradley, Kenneth Bradley, Peggy Bradner, Jan Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Ali Brahim, Jo-Ann Brake, Nicholas Brake, Tyler Branch, Shaela Brandt, Brian Brant, David Brant, Edna Brant, Myron Brataschuk, Colin Brausen, Luis Bravo, Neil Bray, Tess Bray, Gordon Brecht, Debbie Breen, Sharon Breitkreuz, Paul Breland, Stephen Brent, Barry Brenton, Lori Brenton, Ryan Brenton, Roxane Bretzlaff, Olaf Breukel, Anthony Brewer, Lisa Brewer, Butch Briggs, David Briggs, Lynne Brinkworth, Denis Brisebois, Shawn Brockhoff, Kelly Broda, Dwayne Brodziak, John Brogly, Jacobus Bronkhorst, Robert Bronson, Murray Brooker, Andy Brooks, Debbie Brooks, Jeremy Brooks, Tanya Brooks, Kenneth Brosowsky, Christopher Brousseau, Brenda Brown, Carol Brown, Curtis Brown, Eugene Brown, Jason Brown, Jeffery Brown, Jennifer Brown, Jeremy Brown, Leanne Brown, Leroy Brown, Steve Brown, Tyler Brown, Leo Browne, Robert Brownless, Chris Bruce, Shelly Bruce, Kyle Bruggencate, Fred Brugger, John Brule, Marcia Brumec, Russell Brundige, Jason Bryant, Michelle Bryson, Sean Bryson, Richard Buchanan, Gordon Buckshaw, Linda Buczkowski, Bill Budd, Robert Budzen, Raymon Bueckert, Darren Buffett, Wayne Bugiak, Ian Bulloch, Joe Bullock, Don Bumstead, Douglas Bumstead, Alan Bunyan, Clarence Bur, Jeffrey Burchell, Trevor Burchenski, Jeffrey Burdett, David Burdziuk, Keith Bureau, Grant Burgess, Gordon Burhoe, David Burke, Lyle Burke, Ken Burnham, Rob Burns, Barry Burt, Shawn Burt, Gerald Burtch, Robert Busato, Lisa Bush, Colleen Bussey, David Bussey, Robert Butler, Sharjeel Butt, Bob Butterworth, Ronald Butts, Leanne Butz, Peter Buxton, Mike Buytels, Michael Bwalya, David Byrnes, Mike Byrtus, Irina Byvald, Moraima Caceres-Centeno, Krystal Cacka, Mark Cadman, James Cadrain, Ling Cai, Simon Cains, Winnie Calabio, Laura Calder, Leslie Calder, Byron Caldwell, Patrick Caldwell, Tom Callaghan, Natalia Callejas, Patrick Callin, Richard Calliou, Gracell Calonge, Cindy Cameron, Ian Cameron, Ryan Cameron, Shirley Cameron, Lisa Campacci, Catherine Campbell, Clayton Campbell, Darryl Campbell, David Campbell, Dean Campbell, Doug Campbell, Gwen Campbell, Kyle Campbell, Lockhart Campbell, Michael Campbell, Nancy Campbell, Niall Campbell, Andre Campeau, Wayne Campeau, Gregory Cane, Brad Canning, Elaine Cantlon, Kelly Cap, Richard Cap, James Capjack, John Capstick, Barry Carabin, Kathleen Carbury, Angela Cardenas, Fred Cardinal, Jason Cardinal, Lee Cardinal, Sharon Cardinal, Wayne Cardinal, Mark Carew, Justin Carey, Joey Carifelle, Rodger Carifelle, Stephanie Carlson, Wes Carlson, Dean Carnes, Benjamin Carnevali, Albert Caron, Rochelle Caron, Diego Carrera, Michael Carrier, Wayne Carrigan, Greg Carroll, Ian Carroll, Jason Carroll, Shayne Carroll, Melissa Carson, Eduardo 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Brett Chorney, Curtis Chornohos, Eddie Choufi, Rashed Chowdhury, Alphonse Chretien, Marianne Christianson, Shawn Christie, Rob Christopher, Caroline Christopherson, Andy Chu, John Chuiko, Peter Chung, Heather Church, Sharon Church, Gerald Churchill, Natalie Churchill, Roderick Churchill, Kadia Cisse-Banny, Elaine Cissell, Michael Clapham, William Clapperton, Andrew Clare, Andrea Clark, Janice Clark, Kim Clark, Mandy Clark, Bradley Clarke, Ken Clarke, Martha Clarke, Sanja Clarke, Karen Clarkson, Walter Clarkson, Greg Clegg, Reagan Clemmer, Joseph Clevenger, Denise Clifton, Karla Cluett, George Clutton, Brooke Coburn, Dale Coburn, Shirley Cockburn, John Coers, Brenda Coke, Leanne Colborne, Aubrey Colbourne, Rob Coles, Celibeth del Carmen Colina, Lorne Collard, Patrick Colley, Marc Collie, Grant Collier, Garth Collings, Curtis Collins, Jayson Collins, Robert Collins, Rod Collins, Anne Collison, Gordon Collison, Gordon Collison, Adam Collyer, Quinn Conacher, John Condie, Mark Connellan, Deborah Conrad, Spencer Constant, David Conybeare, Chris Cook, Gary Cook, Nicole Cook, Anna Cooke, Kenneth Cooke, Lori Cookson, Rob Coolen, Sean Coolen, Gary Coombe, Kent Cooper, Laura Cooper, David Coppard, Robert Coppard, Nicola Corbett, Mark Corell, Elaine Coreman, Clair Cormier, Rocky Cormier, Rosette Cormier, Ronda Cornell, Grant Corner, Alessandro Corradi, Erin Corrigan, David Corson, Jim Corson, Rhys Corson, Darren Corston, Zaida Cortez, Pierpaolo Corticelli, Harry Costello, Jordan Costley, John Cote, Baba Coulibaly, Sanga Coulibaly, Dougie Coull, Eric Coulombe, Kim Coulter, Jack Courchene, Robert Courchesne, Gerald Courtney, Kathryn Courtney, Dave Cousins, David Cousins, Mark Coutu, Peter Covell, Keith Cowger, Cath Cowie, Craig Cowie, Gemma Cox, Jonathan Cox, Randy Cox, Wade Cox, Jeffrey Coyle, Edward Cozicor, Nigel Crabb, Harry Crabtree, Richard Craft, Cody Craig, Layne Craig, Harlan Craigie, Bruce Crain, Troy Cramm, Marina Crawford, Michael Crawford, Paul Crawford, Paul Crawford, Bernette Crawley, Jessica Crawley, Beverley Creed, Leanne Cressman, Roger Crichton, Kayla Critch, Wendy Crockford, Kevin Croft, Shane Croft, Stefan Croft-Bednarski, Gordon Crooks, David Crosley, Christopher Cross, Ryan Cross, Amber Croswell, Camille Croteau, Barbara Crowley, Linda Cruttenden, Francisco Cruz, Anthony Csabay, Shawn Cudmore, Edgardo Cuello, Darrel Cunningham, Davis Cunningham, Tara Cunningham-Canfield, Ailey Currie, David Currie, Liz Currie, Brent Curtis, Troy Curzon, Dale Cusack, Kenneth Cusack, Pat Cusack, Real Cusson, John Cutler, Daniel Cyr, Bonnie Czaplan, Suzanne Da Costa, Kevin d'Abadie, Victor Dabolin, Andrew Dabrowski, Marivic Dacillo-Basallajes, Fakhri Dadashov, Gary Dahl, Abdelhamid Dahmani, Mark Dailey, Eliane Dakaud, Brittany Dalby, Patrick Dale, Layne Dalgetty-Rouse, Germain Dallaire, Scott Dalrymple, Gary Daly, Noe Damian-Diaz, Stanley Dams, Everett Dana, Rene Dancause, Walter Danchak, Minh Dang, Trevor Daniels, Mike Danis, Gene Danyluk, Peter Danyluk, Daniel Daraban, Babs Daramola, Andrew Darelchuk, Corbin Dargatz, Eric Dargis, Mark Darling, Merl Darragh, Martin Darveau, Altaf Dasurkar, Bruce Davidson, Graham Davidson, Jeffery Davidson, Mike Davidson, Scott Davidson, Thomas Justin Davidson, Todd Davidson, Charlee Davies, Lynne Davies, Frank Davis, Graham Davis, Karen Davis, Randall Davis, Sarah Davis, Peter Davison, Lisa Dawson, David Day, Julia Day, David Daye, Douglas De Avila, Meinrado de Chavez, Eric de Kock, Ryan De Leeuw, Benito De Lorenzo, Robbert de Ruiter, Albert De Sousa, Brian de Winter, David Dean, Harry Dean, Martha Dean, Trevor Debler, Ron Erick DeCastro, Derek Dechaine, James Dechaine, Raymond Dechaine, Roland Dechesne, Neil Deeney, Dave Defoort, Sheldon DeFord, Mervin Degenstien, Barbara Deglow, Karin Delday, Mitchell Dell, Michael Delorme, Michael DeLorme, Charlene DeMone, Whyman Dempster, Chad Denis, Fred Denney, Judy Denney, Brent Dennis, Geoffrey Dennis, Susan Dennis, Kimberley Dennis-Wood, Shirley 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Colleen Wadden, Kyle Waddy, Gene Waller, Valerie Wagar, Todd Waggoner, Trevor Wagil, Joy Wagner, Abdul Waheed, Iris Wahl, Lee Wahl, Donald Wakaruk, Lance Wakefield, Ashley Walchuk, Dave Waldner, Darcy Waldo, David Walker, Dean Wall, Bruce Wallace, Christopher Wallace, Erin Wallace, Greg Wallace, Kevin Wallace, Vince Wallwork, Matthew Walsh, Patrick Walsh, Lorie Walter, Amanda Walters, Michelle Walton, John Wandler, Marilyn Wang, Ping Wang, Qi Wang, Selina Wang, Wenyan Wang, Xiang Wang, Xing Zhu Wang, Blaise Wangler, Kevin Warcimaga, Danny Ward, Kathy Ward, Kirk Ward, Terry Ware, Wayne Warholik, Chris Wark, Wanda Warman, Farooq Warraich, Jason Warren, Rob Warren, Daniel Warrick, Michael Warrick, Dalpreet Warring, Paul Wassell, James Waterfield, Jamie Watkins, Julie Watkins, Brenden Watson, Devon Watson, Kaye Watson, Ken Watson, Debbie Watt, Gordon Watt, Graham Watt, John Watts, Heather Weaver, Alan Webb, Byron Webb, Dustin Webber, Keith Webster, Kim Wee, Eric Weening, Jeff Weibrecht, Derren Weimer, Lionel Weinrauch, Randy Weir, Geoffrey Weisbeck, Brock Weisgerber, Terry Welland, Bonnie Wells, Sheldon Wells, Lisa Welsh, Ryan Welter, Guy Welwood, Mark Wenner, Jeromy Wenzlawe, Dwayne Werle, Craig Werstiuk, Matthew Werstiuk, Barclay Weslake, Ted Wesley, Darrin West, Michael Westad, Kris Westland, Nina Whalen, Troi Whalen, Daniel Wheating, Loyd Wheating, Ceri Wheaton, Joshua Wheaton, Andrew Wheeler, Charmaigne Whelan, Chris Whelan, Judd Whidden, Paul Whitaker, Darcy White, David White, David White, Howard White, Jeffrey White, Nicholas White, Ralph White, Skyler White, Terence White, Dave Whitehouse, Scot Whiteley, Brian Whiting, Michael Whittingham, Heather Whynot, David Wiebe, Malcolm Wiebe, Trevor Wiebe, Troy Wielgus, Darrel Wiens, Debbie Wiens, Cameron Wietzel, Zandra Wigglesworth, Steven Wight, Don Wijesingha, Bob Wilbern, Mason Wilcox, Brandon Wild, Darrell Wilde, Lara Wilde, John Wilding, Daryl Wiles, Chase Wilk, Troy Wilk, Clifton Wilkes, Melanie Wilkie, Pauline Will, Peter Will, Elmer Willard, Stanley Willette, Bill Williams, Brandon Williams, Dorothy Williams, Dustin Williams, Grant Williams, Greg Williams, Julian Williams, Ron Williams, Sherri Williams, Wes Williams, Andrew Williamson, Curtis Williamson, Kelvin Williamson, Malcolm Williamson, Brennon Willick, Jeff Willick, Mark Willis, Robin Willis, David Willms, Christian Willson, Curtis Wilson, Don Wilson, Jeff Wilson, Jim Wilson, Marty Wilson, Patrick Wilson, Tyler Wilson, Woodrow Wilson, Joan Wilton, Betty Winiarz, Jodie Winquist, Ken Winsborrow, Robert Winslow, Craig Winsor, Greg Winters, Garrett Wirachowsky, Morris Wiseman, Paul Wiseman, John Wishart, Michael Witmer, Dale Wittman, Cameron Wlad, Kelly Woidak, Edith Wolfe, Colin Woloshyn, Jennifer Wong, Linda Wong, Lisa Wong, Maggie Wong, Pauline Wong, Julie Woo, Leonard Wood, Lynn Wood, Phil Wood, Roxanne Wood, Timothy Wood, Mark Woodlin, Travis Woods, Marilyn Woodske, Robin Woolner, Sidney Wosnack, Raymond Wourms, Mark Woynarowich, Chris Wright, Richard Wright, Richard Wright, Stephen Wright, Bin Wu, Michael Wu, Kelly Wutzke, Brent Wychopen, George Wyndham, Valerie Wyonzek, Brenda Wyton, Jin Xu, Qiang Xu, James Yakemchuk, Kenneth Yakimowich, Canghu Yang, Daniel Yang, Lin Yang, Zhen Lin Yang, Mike Yanota, Shiquan Yao, Andrew Yaremko, Rick Yarmuch, James Yaroslawsky, Salman Yasin, Noah Yates, Basile Yeboue, Betty Yee, Claire Yeoman, Justin Yeon, Jeffrey Yip, Kitty Yip, Mark Yobb, Yohanna Yohanna, Rockson Yoo, Darrell York, Rachelle Yorke, Daryl Youck, Dale Young, Kevin Young, Loni Young, Lynn Young, Peter Young, Rob Young, Sylvia Young, Eugene Yu, Clement Yuen, Dustin Yuill, Jeff Yuill, William Yuill, Brian Yurchyshyn, Robin Zabek, Armiel Zacharias, Tyler Zachoda, Cam Zackowski, Kent Zahara, Attila Zahorszky, Gabri Zambrano, Doug Zarowny, Kendall Zarowny, Chris Zeebregts, Lynn Zeidler, Tony Zeiser, Aleksandra Zelic, Devon Zell, Warren Zeller, Darcy Zelman, Dennis Zentner, Kathy Zerr, Michelle Zerr, Kendal Zeyha, Rodney Zgierski, Yongxiang Zhai, Jessica Zhang, Yingte Zhang, Adam Zhao, Litong Zhao, Susan Zheng, Zhenkun Zheng, Hong Zhou, Wanli Zhu, Brenda Ziegler, Dwayne Zilinski, Robert Zinselmeyer, Mariola Zisi, Esther Zonderván, Greg Zubiak, Jeremy Zubiak, Aaron Zubot, Adriana Zuniga, Diana Zurabyan.

RESOURCE DISCLOSURE

(1) Bitumen (Thermal Oil)

Discovered Bitumen Initially-in-place	34.5	billion barrels
Proved Company Gross Reserves	0.9	billion barrels of Bitumen
Probable Company Gross Reserves	0.8	billion barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	4.7	billion barrels of Bitumen
Bitumen Produced to Date	0.3	billion barrels
Sub-commercial / Unrecoverable portion of Discovered Bitumen Initially-in-place under current technologies	27.8	billion barrels

(2) Pelican Lake Heavy Crude Oil Pool

Discovered Heavy Crude Oil Initially-in-place	4,100	million barrels
Proved Company Gross Reserves	234	million barrels of heavy crude oil
Probable Company Gross Reserves	104	million barrels of heavy crude oil
Best Estimate Contingent Resources other than Reserves	198	million barrels of heavy crude oil
Heavy Crude Oil Produced to Date	153	million barrels
Sub-commercial / Unrecoverable portion of Discovered Heavy Crude Oil Initially-in-place under current technologies	3,411	million barrels

(3) Horizon Oil Sands Synthetic Crude Oil

Discovered Bitumen Initially-in-place	14.3	billion barrels
Proved Company Gross Reserves	1.9	billion barrels of SCO
Bitumen volume associated with SCO reserves	2.3	billion barrels of Bitumen
Probable Company Gross Reserves	1.0	billion barrels of SCO
Bitumen volume associated with SCO reserves	1.1	billion barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	3.0	billion barrels of Bitumen
Bitumen Produced to Date	0.1	billion barrels of Bitumen
Sub-commercial / Unrecoverable portion of Discovered Bitumen Initially-in-place under current technologies	7.8	billion barrels

Note: All volumes are company gross.

NOTES TO LETTER TO SHAREHOLDERS GRAPHS

(1) Year-end 2009 and 2010 proved plus probable reserves were prepared using forecast prices and costs. Prior to 2009, reserves were prepared using constant prices and costs.

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital investment and repay debt. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(3) Calculated as the net present value of future net revenue of the Company's total proved plus probable reserves prepared using forecast prices and costs discounted at 10%, as reported in the Company's AIF, with $300/acre added for core unproved property ($250/acre for core undeveloped land from 2005 to 2009, $75/acre for core undeveloped land for all years prior to 2005), less net debt and using year end common shares outstanding. Net debt is the Company's long-term debt plus/minus the working capital deficit/surplus. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs have been applied against the future net revenue.

Year-End Reserves

DETERMINATION OF RESERVES

For the year ended December 31, 2010 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated and reviewed the Company's North America and International crude oil, NGL and natural gas reserves. GLJ evaluated the Company's Horizon synthetic crude oil reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the Evaluators as to the Company's reserves.

CORPORATE TOTAL

- Company Gross proved crude oil and NGL reserves increased 8% to 3.80 billion barrels. Company Gross proved natural gas reserves increased 9% to 4.26 Tcf. Total proved BOE increased 8% to 4.51 billion barrels.
- Company Gross proved plus probable crude oil and NGL reserves increased 9% to 5.94 billion barrels. Company Gross proved plus probable natural gas reserves increased 10% to 5.77 Tcf. Total proved plus probable BOE increased 9% to 6.90 billion barrels.
- Company Gross proved reserve additions, including acquisitions, were 433 million barrels of crude oil and NGL and 814 billion cubic feet of natural gas. The total proved reserve replacement ratio on a BOE basis is 246%. Proved undeveloped reserves accounted for 30% of the Corporate total proved reserves.
- On a BOE basis, crude oil and NGLs account for 84% of Company gross proved reserves and 86% of Company gross proved plus probable reserves.

NORTH AMERICA EXPLORATION AND PRODUCTION

- North America company gross proved crude oil and NGL reserves increased 20% to 1.49 billion barrels. Company Gross proved natural gas reserves increased 10% to 4.09 Tcf. Total proved BOE increased 16% to 2.17 billion barrels.
- North America company gross proved plus probable crude oil and NGL reserves increased 22% to 2.50 billion barrels. Company Gross proved plus probable natural gas reserves increased 10% to 5.52 Tcf. Total proved plus probable BOE increased 19% to 3.42 billion barrels.
- North America company gross proved reserve additions, including acquisitions, were 345 million barrels of crude oil and NGL and 805 billion cubic feet of natural gas. The total proved reserve replacement ratio on a BOE basis is 277%. Proved undeveloped reserves accounted for 48% of the North America total proved reserves.

NORTH AMERICA OIL SANDS MINING AND UPGRADING

- Company gross proved synthetic crude oil reserves increased 3% to 1.93 billion barrels.
- Company gross proved plus probable synthetic crude oil reserves increased 2% to 2.89 billion barrels.

INTERNATIONAL EXPLORATION AND PRODUCTION

- North Sea company gross proved reserves decreased 4% to 265 million barrels of oil equivalent due to production and limited reserve adding activity in 2010. North Sea company gross proved plus probable reserves are 394 million barrels of oil equivalent.
- Offshore West Africa company gross proved reserves decreased 11% to 135 million barrels of oil equivalent due to production and technical revisions. Offshore West Africa company gross proved plus probable reserves are 200 million barrels of oil equivalent.

SUMMARY OF COMPANY GROSS OIL AND GAS RESERVES

As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	93	74	153	219	1,804	2,864	44	2,864
Developed Non-Producing	4	20	1	13	–	180	2	70
Undeveloped	13	66	85	687	128	1,048	17	1,171
Total Proved	110	160	239	919	1,932	4,092	63	4,105
Probable	40	57	109	783	956	1,430	20	2,203
Total Proved plus Probable	150	217	348	1,702	2,888	5,522	83	6,308
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	96					87		110
Developed Non-Producing	–					–		–
Undeveloped	24					5		25
Total Proved	120					92		135
Probable	57					46		65
Total Proved plus Probable	177					138		200
Total Company								
Proved								
Developed Producing	267	74	153	219	1,804	2,963	44	3,055
Developed Non-Producing	20	20	1	13	–	217	2	92
Undeveloped	195	66	85	687	128	1,082	17	1,358
Total Proved	482	160	239	919	1,932	4,262	63	4,505
Probable	221	57	109	783	956	1,505	20	2,397
Total Proved plus Probable	703	217	348	1,702	2,888	5,767	83	6,902

SUMMARY OF COMPANY NET OIL AND GAS RESERVES

As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	79	62	120	164	1,483	2,561	30	2,365
Developed Non-Producing	3	16	–	12	–	150	2	58
Undeveloped	11	57	62	535	114	927	13	946
Total Proved	93	135	182	711	1,597	3,638	45	3,369
Probable	33	47	72	600	764	1,232	14	1,735
Total Proved plus Probable	126	182	254	1,311	2,361	4,870	59	5,104
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	82					72		94
Developed Non-Producing	–					–		–
Undeveloped	19					4		20
Total Proved	101					76		114
Probable	48					37		54
Total Proved plus Probable	149					113		168
Total Company								
Proved								
Developed Producing	239	62	120	164	1,483	2,645	30	2,539
Developed Non-Producing	19	16	–	12	–	187	2	80
Undeveloped	188	57	62	535	114	960	13	1,129
Total Proved	446	135	182	711	1,597	3,792	45	3,748
Probable	205	47	72	600	764	1,298	14	1,918
Total Proved plus Probable	651	182	254	1,311	2,361	5,090	59	5,666

NOTES REFERRING TO RESERVES TABLES FROM PAGES 18 TO 22.

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Company Net reserves are working interest share after deduction of royalties and including any royalty interests.
3. Forecast pricing assumptions utilized by the independent qualified reserves evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2011	2012	2013	2014	2015	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	$ 88.40	$ 89.14	$ 88.77	$ 88.88	$ 90.22	1.5%
Western Canada Select (C$/bbl)	$ 80.04	$ 80.71	$ 78.48	$ 76.70	$ 77.86	1.5%
Edmonton Par (C$/bbl)	$ 93.08	$ 93.85	$ 93.43	$ 93.54	$ 94.95	1.5%
Edmonton Pentanes+ (C$/bbl)	$ 95.32	$ 96.11	$ 95.68	$ 95.79	$ 97.24	1.5%
North Sea Brent (US$/bbl)	$ 87.15	$ 87.87	$ 87.48	$ 87.58	$ 88.89	1.5%
Natural gas						
Henry Hub Louisiana (US$/MMBtu)	$ 4.44	$ 5.01	$ 5.32	$ 6.80	$ 6.90	1.5%
AECO (C$/MMBtu)	$ 4.04	$ 4.66	$ 4.99	$ 6.58	$ 6.69	1.5%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.98	$ 4.60	$ 4.93	$ 6.52	$ 6.63	1.5%

A foreign exchange rate of US$0.932/C$1.000 was used in the 2010 evaluation.

4. Reserve additions are comprised of all categories of Company Gross reserve changes, exclusive of production.
5. Reserve replacement ratio is the Company Gross reserve additions divided by the Company Gross production in the same period.
6. Barrels of oil equivalent (BOE) is a conversion ratio of six thousand cubic feet (Mcf) of natural gas to one barrel (bbl) of crude oil.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRODUCT

As of December 31, 2010
Forecast Prices and Costs

PROVED

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2009	100	116	251	732	1,871	3,731	46	3,738
Discoveries	–	1	–	–	–	69	2	15
Extensions	1	20	2	47	–	217	5	111
Infill Drilling	3	25	–	–	–	21	1	33
Improved Recovery	–	–	1	–	–	2	3	4
Acquisitions	12	2	–	109	–	446	7	204
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	–	1	(94)	(1)	(16)
Technical Revisions	6	30	(1)	64	93	144	6	222
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	**110**	**160**	**239**	**919**	**1,932**	**4,092**	**63**	**4,105**
North Sea								
December 31, 2009	265					72		277
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(1)					10		1
Production	(12)					(4)		(13)
December 31, 2010	**252**					**78**		**265**
Offshore West Africa								
December 31, 2009	136					99		152
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(5)					(1)		(5)
Production	(11)					(6)		(12)
December 31, 2010	**120**					**92**		**135**
Total Company								
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	–	1	–	–	–	69	2	15
Extensions	1	20	2	47	–	217	5	111
Infill Drilling	3	25	–	–	–	21	1	33
Improved Recovery	–	–	1	–	–	2	3	4
Acquisitions	12	2	–	109	–	446	7	204
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	–	1	(94)	(1)	(16)
Technical Revisions	–	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**482**	**160**	**239**	**919**	**1,932**	**4,262**	**63**	**4,505**

RECONCILIATION OF COMPANY GROSS RESERVES BY PRODUCT

As of December 31, 2010
Forecast Prices and Costs

PROBABLE

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2009	41	39	106	595	969	1,271	15	1,977
Discoveries	–	–	–	–	–	19	1	4
Extensions	–	8	2	61	–	98	2	89
Infill Drilling	3	10	1	–	–	14	–	16
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	4	1	–	163	–	110	1	187
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	(3)	(26)	–	(7)
Technical Revisions	(8)	(1)	–	(36)	(10)	(55)	1	(63)
Production	–	–	–	–	–	–	–	–
December 31, 2010	**40**	**57**	**109**	**783**	**956**	**1,430**	**20**	**2,203**
North Sea								
December 31, 2009	127					24		131
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(3)					5		(2)
Production	–					–		–
December 31, 2010	**124**					**29**		**129**
Offshore West Africa								
December 31, 2009	63					45		71
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(6)					1		(6)
Production	–					–		–
December 31, 2010	**57**					**46**		**65**
Total Company								
December 31, 2009	231	39	106	595	969	1,340	15	2,179
Discoveries	–	–	–	–	–	19	1	4
Extensions	–	8	2	61	–	98	2	89
Infill Drilling	3	10	1	–	–	14	–	16
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	4	1	–	163	–	110	1	187
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	(3)	(26)	–	(7)
Technical Revisions	(17)	(1)	–	(36)	(10)	(49)	1	(71)
Production	–	–	–	–	–	–	–	–
December 31, 2010	**221**	**57**	**109**	**783**	**956**	**1,505**	**20**	**2,397**

RECONCILIATION OF COMPANY GROSS RESERVES BY PRODUCT

As of December 31, 2010
Forecast Prices and Costs

PROVED PLUS PROBABLE

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2009	141	155	357	1,327	2,840	5,002	61	5,715
Discoveries	–	1	–	–	–	88	3	19
Extensions	1	28	4	108	–	315	7	200
Infill Drilling	6	35	1	–	–	35	1	49
Improved Recovery	–	–	1	–	–	2	3	4
Acquisitions	16	3	–	272	–	556	8	391
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	(2)	(120)	(1)	(23)
Technical Revisions	(2)	29	(1)	28	83	89	7	159
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	**150**	**217**	**348**	**1,702**	**2,888**	**5,522**	**83**	**6,308**
North Sea								
December 31, 2009	392					96		408
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(4)					15		(1)
Production	(12)					(4)		(13)
December 31, 2010	**376**					**107**		**394**
Offshore West Africa								
December 31, 2009	199					144		223
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(11)					–		(11)
Production	(11)					(6)		(12)
December 31, 2010	**177**					**138**		**200**
Total Company								
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	–	1	–	–	–	88	3	19
Extensions	1	28	4	108	–	315	7	200
Infill Drilling	6	35	1	–	–	35	1	49
Improved Recovery	–	–	1	–	–	2	3	4
Acquisitions	16	3	–	272	–	556	8	391
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**703**	**217**	**348**	**1,702**	**2,888**	**5,767**	**83**	**6,902**

Management Discussion and Analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks and Uncertainties" section of this MD&A.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2010. The Company's consolidated financial statements and this MD&A have been prepared in accordance with Canadian GAAP in effect as at and for the year ended December 31, 2010. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in millions of Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2010. The calculation of barrels of oil equivalent ("BOE") is based on a conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead. Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only. The following discussion and analysis refers primarily to the Company's 2010 financial results compared to 2009 and 2008, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2011. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2010, its Annual Information Form for the year ended December 31, 2010, and its audited consolidated financial statements for the year ended December 31, 2010 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 1, 2011.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrels
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	Solid or semi-solid with viscosity greater than 10,000 centipoise
Brent	Dated Brent
C$	Canadian dollars
CAGR	Compound annual growth rate
CAPEX	Capital expenditures
CBM	Coal Bed Methane
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
CSS	Cyclic steam stimulation
EOR	Enhanced oil recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted gravity drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	Generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WCS Heavy Differential	Heavy crude oil differential from WTI
WTI	West Texas Intermediate

OBJECTIVES AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value [(1)] on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil [(2)], primary heavy crude oil, bitumen (thermal oil) and SCO;
- Balance among near-, mid- and long-term projects;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.
(2) Pelican Lake heavy crude oil is 14–17° API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline and cost control are fundamental to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core regions.

Highlights for the year ended December 31, 2010 include the following:

- Achieved net earnings of $1.7 billion, adjusted net earnings from operations of $2.6 billion, and cash flow from operations of $6.3 billion;
- Achieved record yearly production of 632,191 BOE/d;
- Achieved annual crude oil and natural gas production guidance;
- Drilled a record 654 net primary heavy crude oil wells;
- Received Board of Directors sanction and commenced construction of Phase 1 of the Kirby In Situ Oil Sands project;
- Acquired approximately $1.9 billion of crude oil and natural gas properties in the Company's core regions in Western Canada;
- Submitted a joint proposal to the Government of Alberta to construct and operate a bitumen upgrading and refining facility;
- Reduced long-term debt by $1.2 billion to $8.5 billion in 2010 from $9.7 billion in 2009;
- Completed the subdivision of the Company's common shares on a two for one basis;
- Purchased 2,000,000 common shares for a total cost of $68 million under a Normal Course Issuer Bid; and
- Increased annual per share dividend payment to $0.30 from $0.21, our 10th consecutive year of dividend increases.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		**2010**		2009(1)		2008(1)
Revenue, before royalties	**$**	**14,322**	$	11,078	$	16,173
Net earnings	**$**	**1,697**	$	1,580	$	4,985
Per common share – basic and diluted	**$**	**1.56**	$	1.46	$	4.61
Adjusted net earnings from operations (2)	**$**	**2,570**	$	2,689	$	3,492
Per common share – basic and diluted	**$**	**2.36**	$	2.48	$	3.23
Cash flow from operations (3)	**$**	**6,321**	$	6,090	$	6,969
Per common share – basic and diluted	**$**	**5.81**	$	5.62	$	6.45
Dividends declared per common share	**$**	**0.30**	$	0.21	$	0.20
Total assets	**$**	**42,669**	$	41,024	$	42,650
Total long-term liabilities	**$**	**18,528**	$	19,193	$	20,856
Capital expenditures, net of dispositions	**$**	**5,506**	$	2,997	$	7,451

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists the effects of certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)		**2010**		2009		2008
Net earnings as reported	**$**	**1,697**	$	1,580	$	4,985
Stock-based compensation expense (recovery), net of tax (a)(e)		**294**		261		(38)
Unrealized risk management (gain) loss, net of tax (b)		**(16)**		1,437		(2,112)
Unrealized foreign exchange (gain) loss, net of tax (c)		**(160)**		(570)		698
Gabon, Offshore West Africa ceiling test impairment (d)		**672**		–		–
Effect of statutory tax rate and other legislative changes on future income tax liabilities (e)		**83**		(19)		(41)
Adjusted net earnings from operations	**$**	**2,570**	$	2,689	$	3,492

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swap hedges, and are recognized in net earnings.

(d) Performance from the Olowi Field continues to be below expectations. As a result, the Company recognized a pre-tax ceiling test impairment charge of $726 million ($672 million after-tax) at December 31, 2010.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During 2010, the Canadian Federal Government enacted changes to the taxation of stock options surrendered by employees for cash payments. As a result of the changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of future income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense. Income tax rate changes during 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)		**2010**		2009		2008
Net earnings	**$**	**1,697**	$	1,580	$	4,985
Non-cash items:						
Depletion, depreciation and amortization		**4,036**		2,819		2,683
Asset retirement obligation accretion		**107**		90		71
Stock-based compensation expense (recovery)		**294**		355		(52)
Unrealized risk management (gain) loss		**(25)**		1,991		(3,090)
Unrealized foreign exchange (gain) loss		**(180)**		(661)		832
Deferred petroleum revenue tax expense (recovery)		**28**		15		(67)
Future income tax expense (recovery)		**364**		(99)		1,607
Cash flow from operations	**$**	**6,321**	$	6,090	$	6,969

For 2010, the Company reported net earnings of $1,697 million compared to net earnings of $1,580 million for 2009 (2008 – $4,985 million). Net earnings for the year ended December 31, 2010 included net unrealized after-tax expenses of $873 million related to the effects of stock-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a ceiling test impairment charge at Gabon, Offshore West Africa and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2009 – $1,109 million after-tax expenses; 2008 – $1,493 million after-tax income). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2010 decreased to $2,570 million from $2,689 million for 2009 (2008 – $3,492 million).

The decrease in adjusted net earnings from the year ended December 31, 2009 was primarily due to:

- lower realized risk management gains;
- higher depletion, depreciation and amortization expense;
- lower natural gas sales volumes and netbacks; and
- the impact of the stronger Canadian dollar, partially offset by
- the impact of higher crude oil and NGL sales volumes and netbacks.

The impacts of stock-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2010 increased to $6,321 million ($5.81 per common share) from $6,090 million ($5.62 per common share) for 2009 (2008 – $6,969 million; $6.45 per common share). The increase in cash flow from operations from 2009 was primarily due to:

- the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by
- lower realized risk management gains;
- lower natural gas sales volumes and netbacks;
- higher cash taxes; and
- the impact of the stronger Canadian dollar.

For the Company's Exploration and Production activities, the 2010 average sales price per bbl of crude oil and NGLs increased 14% to average $65.81 per bbl from $57.68 per bbl in 2009 (2008 – $82.41 per bbl), and the average natural gas price decreased 10% to average $4.08 per Mcf from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The Company's average sales price of SCO increased 10% to average $77.89 per bbl from $70.83 per bbl in 2009 (2008 – nil).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production was primarily due to higher volumes from the Company's bitumen (thermal oil) and Horizon operations.

Total natural gas production before royalties decreased 5% to average 1,243 MMcf/d from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production primarily reflected natural production declines and the Company's strategic reduction in natural gas drilling activity in North America, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and production volumes from natural gas properties acquired during the year.

Total crude oil and NGLs and natural gas production volumes before royalties increased 10% to average 632,191 BOE/d from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d). Total production for 2010 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2010	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31(1)**
Revenue, before royalties	**$ 14,322**	**$ 3,787**	**$ 3,341**	**$ 3,614**	**$ 3,580**
Net earnings (loss)	**$ 1,697**	**$ (416)**	**$ 580**	**$ 667**	**$ 866**
Net earnings (loss) per common share – basic and diluted	**$ 1.56**	**$ (0.38)**	**$ 0.53**	**$ 0.61**	**$ 0.80**

2009	Total(1)	Dec 31(1)	Sep 30(1)	Jun 30(1)	Mar 31(1)
Revenue, before royalties	$ 11,078	$ 3,319	$ 2,823	$ 2,750	$ 2,186
Net earnings	$ 1,580	$ 455	$ 658	$ 162	$ 305
Net earnings per common share – basic and diluted	$ 1.46	$ 0.42	$ 0.61	$ 0.15	$ 0.28

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

Volatility in quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- Crude oil pricing – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, and the impact of the WCS Heavy Differential from WTI ("WCS Differential") in North America.
- Natural gas pricing – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement and ramp up of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa.
- Natural gas sales volumes – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.
- Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the commencement of operations at Horizon and the Olowi Field and the impact of ceiling test impairments at the Olowi Field.
- Stock-based compensation – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.
- Risk management – Fluctuations due to the recognition of gains and losses from the mark to market and subsequent settlement of the Company's risk management activities.
- Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- Income tax expense – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)		**2010**		2009		2008
WTI benchmark price (US$/bbl)	**$**	**79.55**	$	61.93	$	99.65
Dated Brent benchmark price (US$/bbl)	**$**	**79.50**	$	61.61	$	96.99
WCS blend differential from WTI (US$/bbl)	**$**	**14.26**	$	9.64	$	20.03
WCS blend differential from WTI (%)		**18%**		16%		20%
SCO price (US$/bbl)	**$**	**78.56**	$	61.51	$	102.48
Condensate benchmark price (US$/bbl)	**$**	**81.81**	$	60.60	$	100.10
NYMEX benchmark price (US$/MMBtu)	**$**	**4.42**	$	4.03	$	8.95
AECO benchmark price (C$/GJ)	**$**	**3.91**	$	3.91	$	7.71
US / Canadian dollar average exchange rate	**$**	**0.9709**	$	0.8760	$	0.9381
US / Canadian dollar year end exchange rate	**$**	**1.0054**	$	0.9555	$	0.8166

COMMODITY PRICES

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2010, with a high of approximately $1.01 in December 2010 and a low of approximately $0.93 in May 2010.

WTI pricing was reflective of the slow overall economic recovery in the United States and Europe, with offsetting strong Asian demand mitigating the decline. The relative weakness of the US dollar also contributed to higher WTI pricing. For 2010, WTI averaged US$79.55 per bbl, an increase of 28% compared to US$61.93 per bbl for 2009 (2008 – US$99.65 per bbl).

Brent averaged US$79.50 per bbl for 2010, an increase of 29% compared to US$61.61 per bbl for 2009 (2008 – US$96.99 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which is more reflective of international markets and the overall supply and demand balance. Brent pricing was reflective of continued strong demand from Asian markets. The increase in Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude at Cushing during portions of 2010.

The WCS Differential averaged 18% of WTI for 2010 compared to 16% for 2009 (2008 – 20%). The widening WCS Differential was partially due to pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of the continuing economic recovery. The WCS Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.42 per MMBtu for 2010, an increase of 10% from US$4.03 per MMBtu for 2009 (2008 – US$8.95 per MMBtu). Alberta based AECO natural gas pricing for 2010 averaged $3.91 per GJ and was comparable to average prices in 2009 (2008 – $7.71 per GJ). Natural gas prices continue to be depressed due to strong US shale gas production limiting the upside to natural gas price recovery.

OPERATING, ROYALTY AND CAPITAL COSTS

Strong commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants. In the province of Alberta, GHG regulations came into effect July 1, 2008, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant, face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO_2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO_2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that would likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2008) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2009 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Initial changes to the Alberta royalty regime under the ARF included the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

During 2010, the Government of Alberta modified crude oil and natural gas royalty rates. These changes included:

- Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for coalbed methane and shale gas wells to the first 36 months after start of production, subject to volume limits of 750 MMcfe for coalbed methane and no volume limits for shale gas.
- Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for horizontal natural gas and crude oil wells. The period for horizontal natural gas wells has been extended to the first 18 months after start of production, and volumes of 500 MMcfe. Limits on production months and volumes for crude oil will be set according to the measured depth of the wells.
- Effective January 1, 2011, a reduction in the maximum royalty rate to 5% on new natural gas and crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 MMcfe and 50,000 BOE respectively.
- Effective January 1, 2011, a reduction in the maximum royalty rate for crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Modifications were also made to the natural gas deep drilling program, including changes to depth requirements. The Government of Alberta also announced changes to the price components of oil and gas royalty formulas to reduce the royalty rate at prices higher than $85.00 per bbl and $5.25 per GJ respectively.

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

		Changes due to				**Changes due to**			
($ millions)	2008	Volumes	Prices	Other	2009	**Volumes**	**Prices**	**Other**	**2010**
North America									
Crude oil and NGLs	$ 8,811	$ (424)	$ (2,649)	$ –	$ 5,738	**$ 938**	**$ 1,127**	**$ 2**	**$ 7,805**
Natural Gas	4,685	(598)	(1,852)	–	2,235	**(121)**	**(206)**	**–**	**1,908**
	13,496	(1,022)	(4,501)	–	7,973	**817**	**921**	**2**	**9,713**
North Sea									
Crude oil and NGLs	1,753	(344)	(465)	–	944	**(71)**	**171**	**(1)**	**1,043**
Natural gas	16	–	1	–	17	**–**	**(2)**	**–**	**15**
	1,769	(344)	(464)	–	961	**(71)**	**169**	**(1)**	**1,058**
Offshore West Africa									
Crude oil and NGLs	895	413	(436)	–	872	**(130)**	**104**	**–**	**846**
Natural gas	49	18	(26)	–	41	**(6)**	**3**	**–**	**38**
	944	431	(462)	–	913	**(136)**	**107**	**–**	**884**
Subtotal									
Crude oil and NGLs	11,459	(355)	(3,550)	–	7,554	**737**	**1,402**	**1**	**9,694**
Natural gas	4,750	(580)	(1,877)	–	2,293	**(127)**	**(205)**	**–**	**1,961**
	16,209	(935)	(5,427)	–	9,847	**610**	**1,197**	**1**	**11,655**
Oil Sands Mining and Upgrading	–	1,253	–	–	1,253	**1,175**	**221**	**–**	**2,649**
Midstream	77	–	–	(5)	72	**–**	**–**	**7**	**79**
Intersegment eliminations and other (1)	(113)	–	–	19	(94)	**–**	**–**	**33**	**(61)**
Total	$ 16,173	$ 318	$ (5,427)	$ 14	$ 11,078	**$ 1,785**	**$ 1,418**	**$ 41**	**$ 14,322**

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Revenue increased 29% to $14,322 million for 2010 from $11,078 million for 2009 (2008 – $16,173 million). The increase was primarily due to an increase in realized crude oil and NGL prices and volumes, partially offset by a decrease in realized natural gas prices and volumes.

For 2010, 13% of the Company's crude oil and natural gas revenue was generated outside of North America (2009 – 17%; 2008 – 17%). North Sea accounted for 7% of crude oil and natural gas revenue for 2010 (2009 – 9%; 2008 – 11%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2010 (2009 – 8%; 2008 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**270,562**	234,523	243,826
North America – Oil Sands Mining and Upgrading	**90,867**	50,250	–
North Sea	**33,292**	37,761	45,274
Offshore West Africa	**30,264**	32,929	26,567
	424,985	355,463	315,667
Natural gas (MMcf/d)			
North America	**1,217**	1,287	1,472
North Sea	**10**	10	10
Offshore West Africa	**16**	18	13
	1,243	1,315	1,495
Total barrels of oil equivalent (BOE/d)	**632,191**	574,730	564,845
Product mix			
Light and medium crude oil and NGLs	**18%**	21%	22%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**15%**	15%	16%
Bitumen (thermal oil)	**14%**	11%	12%
Synthetic crude oil	**14%**	9%	–
Natural gas	**33%**	38%	44%
Percentage of gross revenue [(1)] (excluding midstream revenue)			
Crude oil and NGLs	**85%**	78%	68%
Natural gas	**15%**	22%	32%

(1) Net of transportation and blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**219,736**	201,873	207,933
North America – Oil Sands Mining and Upgrading	**87,763**	48,833	–
North Sea	**33,227**	37,683	45,182
Offshore West Africa	**28,288**	29,922	22,641
	369,014	318,311	275,756
Natural gas (MMcf/d)			
North America	**1,168**	1,214	1,225
North Sea	**10**	10	10
Offshore West Africa	**15**	17	11
	1,193	1,241	1,246
Total barrels of oil equivalent (BOE/d)	**567,743**	525,103	483,541

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Total production averaged 632,191 BOE/d for 2010, a 10% increase from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d for 2010 from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production from 2009 was primarily due to higher volumes from the Company's bitumen (thermal oil) and Horizon operations. Crude oil and NGLs production for 2010 was within the Company's previously issued guidance of 423,000 to 430,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 33% of the Company's total production in 2010. Total natural gas production before royalties decreased 5% to 1,243 MMcf/d for 2010 from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production from 2009 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year. Natural gas production for 2010 was within the Company's previously issued guidance of 1,242 to 1,250 MMcf/d.

For 2011, annual production is forecasted to average between 385,000 and 427,000 bbl/d of crude oil and NGLs and between 1,177 and 1,246 MMcf/d of natural gas.

NORTH AMERICA – EXPLORATION AND PRODUCTION

North America crude oil and NGLs production for 2010 increased 15% to average 270,562 bbl/d from 234,523 bbl/d for 2009 (2008 – 243,826 bbl/d). The increase in production from 2009 was primarily due to the cyclic nature of the Company's bitumen (thermal oil) production and the results of the impact of a record heavy oil drilling program.

North America natural gas production for 2010 decreased 5% to average 1,217 MMcf/d from 1,287 MMcf/d for 2009 (2008 – 1,472 MMcf/d). The decrease in natural gas production from 2009 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by results of new production from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year.

NORTH AMERICA – OIL SANDS MINING AND UPGRADING

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 90,867 bbl/d for 2010, an increase of 81% from 50,250 bbl/d for 2009. The increase in production of synthetic crude oil from 2009 reflected the Company's focus on reliability improvements and ramping up of production.

NORTH SEA

North Sea crude oil production for 2010 was 33,292 bbl/d, a decrease of 12% from 37,761 bbl/d for 2009 (2008 – 45,274 bbl/d). The decrease in production volumes from 2009 was due to natural field declines and timing of scheduled maintenance shut downs in 2010.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production for 2010 decreased 8% to 30,264 bbl/d from 32,929 bbl/d for 2009 (2008 – 26,567 bbl/d), due to natural field declines.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels as follows:

(bbl)	**2010**	2009	2008
North America – Exploration and Production	**761,351**	1,131,372	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,172,200**	1,224,481	–
North Sea	**264,995**	713,112	558,904
Offshore West Africa	**404,197**	51,103	1,113,156
	2,602,743	3,120,068	2,433,411

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	2010	2009	2008
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 65.81**	$ 57.68	$ 82.41
Royalties	**10.09**	6.73	10.48
Production expense	**14.16**	15.92	16.26
Netback	**$ 41.56**	$ 35.03	$ 55.67
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 4.08**	$ 4.53	$ 8.39
Royalties (3)	**0.20**	0.32	1.46
Production expense	**1.09**	1.08	1.02
Netback	**$ 2.79**	$ 3.13	$ 5.91
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 49.90**	$ 44.87	$ 68.62
Royalties	**6.72**	4.72	9.78
Production expense	**11.25**	11.98	11.79
Netback	**$ 31.93**	$ 28.17	$ 47.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1) (2)						
North America	**$**	**62.28**	$	54.70	$	77.42
North Sea	**$**	**82.49**	$	68.84	$	100.31
Offshore West Africa	**$**	**78.93**	$	65.27	$	97.96
Company average	**$**	**65.81**	$	57.68	$	82.41
Natural gas ($/Mcf) (1) (2)						
North America	**$**	**4.05**	$	4.51	$	8.41
North Sea	**$**	**3.83**	$	4.66	$	4.09
Offshore West Africa	**$**	**6.63**	$	6.11	$	10.03
Company average	**$**	**4.08**	$	4.53	$	8.39
Company average ($/BOE) (1) (2)	**$**	**49.90**	$	44.87	$	68.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

Realized crude oil and NGLs prices increased 14% to average $65.81 per bbl for 2010 from $57.68 per bbl for 2009 (2008 – $82.41 per bbl). The increase in 2010 was primarily a result of higher WTI and Brent benchmark crude oil prices during the year, partially offset by the impact of a widening WCS Differential and the stronger Canadian dollar relative to the US dollar during 2010.

The Company's realized natural gas price decreased 10% to average $4.08 per Mcf for 2010 from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The decrease in 2010 was primarily due to higher benchmark prices resulting from lower demand and high storage levels, strong incremental production from shale gas plays, the widening NYMEX and AECO differential and the impact of a stronger Canadian dollar relative to the US dollar.

NORTH AMERICA

North America realized crude oil prices increased 14% to average $62.28 per bbl for 2010 from $54.70 per bbl for 2009 (2008 – $77.42 per bbl). The increase in 2010 was primarily due to higher WTI benchmark pricing, partially offset by the impact of the widening WCS Differential and the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2010, the Company contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil blend on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2013 upon completion of the pipeline expansion and are subject to receipt of regulatory approval of the pipeline expansion.

Subsequent to December 31, 2010, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of this detailed engineering and final project sanction by the respective parties.

North America realized natural gas prices decreased 10% to average $4.05 per Mcf for 2010 from $4.51 per Mcf for 2009 (2008 – $8.41 per Mcf), primarily related to lower benchmark prices due to lower demand and high storage levels, the widening NYMEX and AECO differential, strong incremental production from shale gas plays, the impact of natural gas physical sales contracts in 2009 and the impact of a stronger Canadian dollar relative to the US dollar.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		2010		2009		2008
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**68.02**	$	57.02	$	89.04
Pelican Lake heavy crude oil (C$/bbl)	**$**	**61.69**	$	55.52	$	76.91
Primary heavy crude oil (C$/bbl)	**$**	**62.04**	$	55.66	$	74.91
Bitumen (thermal oil) (C$/bbl)	**$**	**59.55**	$	51.18	$	71.89
Natural gas (C$/Mcf)	**$**	**4.05**	$	4.51	$	8.41

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

NORTH SEA

North Sea realized crude oil prices increased 20% to average $82.49 per bbl for 2010 from $68.84 per bbl for 2009 (2008 – $100.31 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in the North Sea from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 21% to average $78.93 per bbl for 2010 from $65.27 per bbl for 2009 (2008 – $97.96 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in Offshore West Africa from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**11.85**	$	7.93	$	11.99
North Sea	**$**	**0.16**	$	0.14	$	0.21
Offshore West Africa	**$**	**5.54**	$	5.79	$	14.81
Company average	**$**	**10.09**	$	6.73	$	10.48
Natural gas ($/Mcf) (1)						
North America (2)	**$**	**0.20**	$	0.32	$	1.47
Offshore West Africa	**$**	**0.53**	$	0.53	$	1.52
Company average	**$**	**0.20**	$	0.32	$	1.46
Company average ($/BOE) (1)	**$**	**6.72**	$	4.72	$	9.78
Percentage of revenue (3)						
Crude oil and NGLs		**15%**		12%		13%
Natural gas (2)		**5%**		7%		17%
BOE		**13%**		11%		14%

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.
(3) Net of transportation and blending costs and excluding risk management activities.

NORTH AMERICA

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the ARF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

Crude oil and NGLs royalties for 2010 compared to 2009 reflected higher realized crude oil prices and averaged approximately 19% of gross revenues for 2010 compared to 14% for 2009 (2008 – 15%). North America crude oil and NGLs royalties per bbl are anticipated to average 16% to 20% of gross revenue for 2011.

Natural gas royalties averaged approximately 5% of gross revenues for 2010 compared to 7% for 2009 (2008 – 18%), primarily due to lower benchmark natural gas prices. North America natural gas royalties per Mcf are anticipated to average 4% to 6% of gross revenue for 2011.

NORTH SEA

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

OFFSHORE WEST AFRICA

Under the terms of the Production Sharing Contracts ("PSCs"), royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 7% for 2010 compared to 9% for 2009 (2008 – 15%). Offshore West Africa royalty rates are anticipated to average 13% to 15% of gross revenue for 2011, as a result of the expected payout of the Baobab Field.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**12.14**	$	14.63	$	14.96
North Sea	**$**	**29.73**	$	26.98	$	26.29
Offshore West Africa	**$**	**14.64**	$	12.83	$	10.29
Company average	**$**	**14.16**	$	15.92	$	16.26
Natural gas ($/Mcf) (1)						
North America	**$**	**1.06**	$	1.07	$	1.00
North Sea	**$**	**2.91**	$	2.16	$	2.51
Offshore West Africa	**$**	**1.76**	$	1.23	$	1.61
Company average	**$**	**1.09**	$	1.08	$	1.02
Company average ($/BOE) (1)	**$**	**11.25**	$	11.98	$	11.79

(1) Amounts expressed on a per unit basis are based on sales volumes.

NORTH AMERICA

North America crude oil and NGLs production expense for 2010 decreased 17% to $12.14 per bbl from $14.63 per bbl for 2009 (2008 – $14.96 per bbl). The decrease in production expense per bbl from 2009 was primarily a result of higher production volumes and lower cost of natural gas for fuel for the Company's bitumen (thermal oil) operations.

North America natural gas production expense for 2010 was $1.06 per Mcf, comparable to 2009 production expense at $1.07 per Mcf (2008 – $1.00 per Mcf), as lower service costs offset the effects of lower production volumes.

NORTH SEA

North Sea crude oil production expense for 2010 increased 10% to $29.73 per bbl from $26.98 per bbl for 2009 (2008 - $26.29 per bbl). Production expense increased on a per barrel basis due to lower volumes on relatively fixed costs.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expense for 2010 increased 14% to $14.64 per bbl from $12.83 per bbl for 2009 (2008 - $10.29 per bbl). Production expense increased on a per barrel basis due to the timing of liftings for each field, including the impact of costs associated with the Olowi Field which has higher production expenses than the Espoir and Baobab fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	**$**	**2,336**	$	2,060	$	2,236
North Sea		**303**		261		317
Offshore West Africa		**1,023**		335		132
Expense	**$**	**3,662**	$	2,656	$	2,685
$/BOE	**$**	**18.49**	$	13.82	$	12.97

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") expense for 2010 increased to $3,662 million from $2,656 million for 2009 (2008 – $2,685 million), primarily due to higher production in North America, an increase in the estimated future costs to develop the Company's proved undeveloped reserves in the North Sea and the impact of a ceiling test impairment related to Gabon, Offshore West Africa at December 31, 2010.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	**$**	**46**	$	41	$	42
North Sea		**33**		24		27
Offshore West Africa		**6**		4		2
Expense	**$**	**85**	$	69	$	71
$/BOE	**$**	**0.43**	$	0.36	$	0.34

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for 2010 increased from 2009 primarily due to higher asset retirement obligations recognized in the North Sea in 2009.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

($/bbl) [1]		**2010**		2009		2008
SCO sales price [2]	**$**	**77.89**	$	70.83	$	–
Bitumen value for royalty purposes [3]	**$**	**56.14**	$	56.57	$	–
Bitumen royalties [4]	**$**	**2.72**	$	2.15	$	–

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation.
(3) Calculated as the simple average of the monthly bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices increased 10% to average $77.89 per bbl for the year ended December 31, 2010 from $70.83 per bbl for the year ended December 31, 2009. The increase in SCO prices from 2009 was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar. There is an active market for SCO throughout North America.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 15 to the Company's consolidated financial statements.

($ millions)		**2010**		2009		2008
Cash costs, excluding natural gas costs	**$**	**1,082**	$	599	$	–
Natural gas costs		**126**		84		–
Total cash production costs	**$**	**1,208**	$	683	$	–

($/bbl) [1]		**2010**		2009		2008
Cash costs, excluding natural gas costs	**$**	**32.58**	$	34.97	$	–
Natural gas costs		**3.78**		4.92		–
Total cash production costs	**$**	**36.36**	$	39.89	$	–
Sales (bbl/d)		**91,010**		46,896		–

(1) Amounts expressed on a per unit basis are based on sales volumes.

First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $36.36 per bbl for 2010 compared to $39.89 per bbl for 2009. The decrease in cash production costs was primarily due to the Company's ongoing focus on planned maintenance, reliability improvements and the stabilization of production volumes at levels approaching plant capacity.

($ millions)		**2010**		2009		2008
Depreciation, depletion and amortization	**$**	**366**	$	187	$	–
Asset retirement obligation accretion		**22**		21		–
Total	**$**	**388**	$	208	$	–

($/bbl) [1]		**2010**		2009		2008
Depreciation, depletion and amortization	**$**	**11.02**	$	10.95	$	–
Asset retirement obligation accretion		**0.67**		1.22		–
Total	**$**	**11.69**	$	12.17	$	–

(1) Amounts expressed on a per unit basis are based on sales volumes.

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced. Depletion, depreciation and amortization increased in 2010 compared to 2009 primarily due to higher sales volumes and the impact of certain assets depreciated on a straight-line basis.

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

MIDSTREAM

($ millions)		2010		2009		2008
Revenue	$	**79**	$	72	$	77
Production expense		**22**		19		25
Midstream cash flow		**57**		53		52
Depreciation		**8**		9		8
Segment earnings before taxes	$	**49**	$	44	$	44

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts) (1)		2010		2009		2008
Expense	$	**210**	$	181	$	180
$/BOE	$	**0.91**	$	0.87	$	0.87

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2010 increased from 2009 due to higher staffing and general corporate costs.

STOCK-BASED COMPENSATION

($ millions)		2010		2009		2008
Expense (recovery)	$	**294**	$	355	$	(52)

The Company's Stock Option Plan (the "Option Plan") was designed to provide current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. As a result of enacted changes to Canadian income tax legislation in 2010 related to the cash surrender of options, the Company anticipates that Canadian based employees will now choose to exercise their options to receive newly issued common shares rather than surrender their options for cash payment.

The Company recorded a $294 million stock-based compensation expense during 2010 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the year, and the 17% increase in the Company's share price for the year ended December 31, 2010 (December 31, 2010 – $44.35; December 31, 2009 – $38.00; December 31, 2008 – $24.38; December 31, 2007 – $36.29). The Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. For the year ended December 31, 2010, the Company capitalized $24 million in stock-based compensation to Oil Sands Mining and Upgrading (2009 – $2 million capitalized; 2008 – $23 million recovery).

The stock-based compensation liability at December 31, 2010, reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price. In periods when substantial stock price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2010, the Company paid $45 million for stock options surrendered for cash settlement (2009 – $94 million; 2008 – $207 million).

INTEREST EXPENSE

($ millions, except per BOE amounts and interest rates) (1)		2010		2009		2008
Expense, gross	$	**477**	$	516	$	609
Less: capitalized interest, Oil Sands Mining and Upgrading		**28**		106		481
Expense, net	$	**449**	$	410	$	128
$/BOE	$	**1.94**	$	1.96	$	0.62
Average effective interest rate		**5.0%**		4.3%		5.1%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense for 2010 decreased from 2009 due to lower debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by the impact of higher variable interest rates. The Company's average effective interest rate increased from 2009 primarily due to an increased weighting of fixed versus floating rate debt and higher variable interest rates.

During 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		2010		2009		2008
Crude oil and NGLs financial instruments	$	**84**	$	(1,330)	$	2,020
Natural gas financial instruments		**(234)**		(33)		(21)
Foreign currency contracts and interest rate swaps		**54**		110		(139)
Realized (gain) loss	$	**(96)**	$	(1,253)	$	1,860
Crude oil and NGLs financial instruments	$	**(108)**	$	2,039	$	(3,104)
Natural gas financial instruments		**71**		(58)		16
Foreign currency contracts and interest rate swaps		**12**		10		(2)
Unrealized (gain) loss	$	**(25)**	$	1,991	$	(3,090)
Net (gain) loss	$	**(121)**	$	738	$	(1,230)

Complete details related to outstanding derivative financial instruments at December 31, 2010 are disclosed in note 12 to the Company's consolidated financial statements.

The cash settlement amount of commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2010.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $25 million ($16 million after-tax) on its risk management activities for the year ended December 31, 2010 (2009 – $1,991 million unrealized loss, $1,437 million after-tax; 2008 – $3,090 million unrealized gain, $2,112 million after-tax).

FOREIGN EXCHANGE

($ millions)		2010		2009		2008
Net realized (gain) loss	$	**(2)**	$	30	$	(114)
Net unrealized (gain) loss (1)		**(180)**		(661)		832
Net (gain) loss	$	**(182)**	$	(631)	$	718

(1) Amounts are reported net of the hedging effect of cross currency swap hedges.

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. The majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange gain in 2010 was primarily related to the strengthening Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. Included in the net unrealized gain for the year ended December 31, 2010 was an unrealized loss of $101 million (2009 – $338 million unrealized loss, 2008 – $449 million unrealized gain) related to the impact of cross currency swap hedges. The net realized foreign exchange gain for 2010 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$1.0054 compared to US$0.9555 at December 31, 2009 (December 31, 2008 – US$0.8166).

TAXES

($ millions, except income tax rates)	2010	2009	2008
Current	$ 91	$ 91	$ 245
Deferred	28	15	(67)
Taxes other than income tax	**$ 119**	$ 106	$ 178
North America (1)	$ 432	$ 28	$ 33
North Sea	203	278	340
Offshore West Africa	63	82	128
Current income tax	**698**	388	501
Future income tax	**364**	(99)	1,607
	1,062	289	2,108
Income tax rate and other legislative changes (2) (3) (4)	**(83)**	19	41
	$ 979	$ 308	$ 2,149
Effective income tax rate before income tax rate and other legislative changes	**28.1%**	24.3%	27.8%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) During 2010, future income tax expense included a charge of $83 million related to enacted changes to the taxation of stock options surrendered by employees in Canada for cash.
(3) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions enacted during 2009.
(4) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions enacted during 2008.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that may ultimately arise from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $350 million to $450 million in Canada and $280 million to $320 million in the North Sea and Offshore West Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	2010	2009	2008
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 1,904**	$ 6	$ 336
Land acquisition and retention	**141**	77	86
Seismic evaluations	**100**	73	107
Well drilling, completion and equipping	**1,500**	1,244	1,664
Production and related facilities	**1,122**	977	1,282
Total net reserve replacement expenditures	**4,767**	2,377	3,475
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	**–**	69	2,732
Horizon Phase 1 commissioning costs and other	**–**	202	364
Horizon Phases 2/3 construction costs	**319**	104	336
Capitalized interest, stock-based compensation and other	**88**	98	480
Sustaining capital	**128**	80	–
Total Oil Sands Mining and Upgrading [2]	**535**	553	3,912
Midstream	**7**	6	9
Abandonments [3]	**179**	48	38
Head office	**18**	13	17
Total net capital expenditures	**$ 5,506**	$ 2,997	$ 7,451
By segment			
North America	**$ 4,369**	$ 1,663	$ 2,344
North Sea	**149**	168	319
Offshore West Africa	**246**	544	811
Other	**3**	2	1
Oil Sands Mining and Upgrading	**535**	553	3,912
Midstream	**7**	6	9
Abandonments [3]	**179**	48	38
Head office	**18**	13	17
Total	**$ 5,506**	$ 2,997	$ 7,451

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(3) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's operating strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2010 were $5,506 million compared to $2,997 million for 2009 (2008 – $7,451 million). The increase in capital expenditures from the prior year was primarily due to the purchase of crude oil and natural gas producing properties and unproved land in the Company's core regions in Western Canada and the increase in the Company's abandonment program.

Drilling Activity (number of wells)	2010	2009	2008
Net successful natural gas wells	**92**	109	269
Net successful crude oil wells	**934**	644	682
Dry wells	**33**	46	39
Stratigraphic test / service wells	**491**	329	131
Total	**1,550**	1,128	1,121
Success rate (excluding stratigraphic test / service wells)	**97%**	94%	96%

NORTH AMERICA

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2010 compared to approximately 58% for 2009 (2008 – 32%).

During 2010, the Company targeted 98 net natural gas wells, including 26 wells in Northeast British Columbia, 21 wells in the Northern Plains region, 46 wells in Northwest Alberta, and 5 wells in the Southern Plains region. The Company also targeted 953 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 654 primary heavy crude oil wells, 175 Pelican Lake heavy crude oil wells, 17 bitumen (thermal oil) wells and 15 light crude oil wells were drilled. Another 92 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2010, the Company drilled 17 thermal oil wells, and 58 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2010 was approximately 90,000 bbl/d (2009 – 64,000 bbl/d; 2008 – 65,000 bbl/d). The Primrose East Expansion was completed and first steaming commenced in September 2008, with first production achieved in the first quarter of 2009. During 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. The Company received approval from regulators to commence steaming on the next cycle in the third quarter of 2010.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter, the Company's Board of Directors sanctioned Kirby Phase 1. Construction commenced in the fourth quarter of 2010, with first steam targeted in 2013.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout 2010. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 38,000 bbl/d in 2010 (2009 – 37,000 bbl/d; 2008 – 37,000 bbl/d).

For 2011, the Company's overall drilling activity in North America is expected to comprise approximately 72 natural gas wells and 1,186 crude oil wells, excluding stratigraphic and service wells.

OIL SANDS MINING AND UPGRADING

Phase 2/3 spending during 2010 continued to be focused on construction of the third Ore Preparation Plant, additional product tankage, the butane treatment unit, the sulphur recovery unit, and hydro-transport.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to one of the coke drums. Production capacity at Horizon has been suspended during the investigation and repair/rebuild to plant equipment damaged by the fire.

A preliminary assessment of the extent of damage and timelines to repair/rebuild indicate that the coke drums are serviceable. The procurement process for all necessary replacement components and parts for the damage caused by the fire has been initiated. Based on preliminary estimates, the first set of coke drums is targeted to resume production in the second quarter of 2011 with production rates of approximately 55,000 bbl/d. The second set of coke drums is currently targeted to be on production in the third quarter of 2011.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

NORTH SEA

During 2010, the Company drilled 0.9 net oil wells and 0.9 net injection wells at Ninian following commencement of drilling in the second quarter of the year. The Company also successfully completed planned maintenance shutdowns at all of its production facilities in the year.

The Company plans to continue drilling at Ninian during 2011 and commence drilling at Murchison in the second quarter of 2011. The Company also continues to focus on developing and high grading its inventory of drilling locations for future execution.

OFFSHORE WEST AFRICA

The Company drilled 7.1 wells during 2010. First crude oil was achieved on the Olowi Field on Platform B in the second quarter of the year, and on Platform A in the fourth quarter of the year. At Espoir, facilities upgrades were completed and incremental production volumes delivered during 2010.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**2010**	2009	2008
Working capital (deficit) (1)	**$ (984)**	$ (514)	$ 392
Long-term debt (2) (3)	**$ 8,499**	$ 9,658	$ 13,016
Shareholders' equity			
Share capital	**$ 3,147**	$ 2,834	$ 2,768
Retained earnings	**18,005**	16,696	15,344
Accumulated other comprehensive (loss) income	**(167)**	(104)	262
Total	**$ 20,985**	$ 19,426	$ 18,374
Debt to book capitalization (3) (4)	**29%**	33%	41%
Debt to market capitalization (3) (5)	**15%**	19%	33%
After-tax return on average common shareholders' equity (6)	**8%**	8%	33%
After-tax return on average capital employed (3) (7)	**7%**	6%	19%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2010 – $nil; 2009 – $nil; 2008 – $420 million).
(3) Long-term debt at December 31, 2010, 2009 and 2008 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed.

At December 31, 2010, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

The Company believes that its capital resources are sufficient to compensate for any short term cash flow reductions arising from Horizon, and accordingly, the Company's targeted capital program currently remains unchanged for 2011. At December 31, 2010, the Company had $2,444 million of available credit under its bank credit facilities. During 2010, the Company repaid $400 million of the medium term notes bearing interest at 5.50%. Long-term debt was $8,499 million at December 31, 2010, resulting in a debt to book capitalization ratio of 29% (December 31, 2009 – 33%; December 31, 2008 – 41%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. Further details related to the Company's long-term debt at December 31, 2010 are discussed in note 5 to the Company's consolidated financial statements.

During 2009, the Company filed new base shelf prospectuses that allowed for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at December 31, 2010, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2010 are discussed in note 12 to the Company's consolidated financial statements.

SHARE CAPITAL

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010, with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

As at December 31, 2010, there were 1,090,848,000 common shares outstanding and 66,844,000 stock options outstanding. As at March 1, 2011, the Company had 1,093,711,000 common shares outstanding and 63,029,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend declared by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from the prior year, recognizing the stability of the Company's cash flow and providing a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2010, an increase in the annual dividend paid by the Company to $0.30 per common share was approved for 2010. The increase represented a 43% increase from 2009.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12-month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at March 1, 2011, 2,000,000 common shares had been purchased for cancellation at an average price of $33.77 per common share, for a total cost of $68 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at December 31, 2010, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating lease	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2010.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

RESERVES

For the year ended December 31, 2010, the Company retained Qualified Independent Reserves Evaluators to evaluate and review all of the Company's proved, as well as proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

In previous years, the Company had been granted an exemption order from the securities regulators in Canada that allowed substitution of United States SEC requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the Company's gross proved and proved plus probable reserves as at December 31, 2010, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1	(94)	(1)	(16)
Technical Revisions	-	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**482**	**160**	**239**	**919**	**1,932**	**4,262**	**63**	**4,505**

Proved plus Probable Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**703**	**217**	**348**	**1,702**	**2,888**	**5,767**	**83**	**6,902**

At December 31, 2010, the Company's gross proved crude oil and NGLs reserves totaled 3,795 MMbbl, and gross proved plus probable crude oil and NGLs reserves totaled 5,941 MMbbl. Proved reserve additions and revisions replaced 279% of 2010 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 241 MMbbl, and additions to proved plus probable reserves amounted to 498 MMbbl. Net positive revisions amounted to 192 MMbbl for proved reserves and 126 MMbbl for proved plus probable reserves. The net gains were primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

At December 31, 2010, the Company's gross proved natural gas reserves totaled 4,262 Bcf, and gross proved plus probable natural gas reserves totaled 5,767 Bcf. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 755 Bcf, and additions to proved plus probable reserves amounted to 996 Bcf. Net positive revisions for proved reserves amounted to 59 Bcf primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance partially offset by economic factors. Net negative revisions for proved plus probable reserves amounted to 16 Bcf primarily due to lower benchmark natural gas pricing.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining reserves.

Information with respect to estimated benchmark future pricing is included in note 4 to the Company's consolidated financial statements. The crude oil, NGL and natural gas reference pricing and inflation and exchange rates used in the preparation of reserves are as per the Sproule price forecast dated December 31, 2010. Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following items:

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserve estimates;
- Prevailing prices of crude oil and NGLs, and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
- Success of exploration and development activities;
- Timing and success of integrating the business and operations of acquired companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as the majority of sales are based in US dollars;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Mechanical or equipment failure of facilities and infrastructure;
- Risk of catastrophic loss due to fire, explosion or acts of nature;
- Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk to an acceptable level. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional detail regarding the Company's risks and uncertainties, refer to the Company's AIF.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

- An internal environmental compliance audit and inspection program of the Company's operating facilities;
- A suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A due diligence program related to groundwater monitoring;
- An active program related to preventing and reclaiming spill sites;
- A solution gas conservation program;
- A program to replace the majority of fresh water for steaming with brackish water;
- Water programs to improve efficiency of use, recycle rates and water storage;
- Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
- Reporting for environmental liabilities;
- A program to optimize efficiencies at the Company's operated facilities;
- Continued evaluation of new technologies to reduce environmental impacts;
- Implementation of a tailings management plan; and
- CO_2 reduction programs including the injection of CO_2 into tailings and for use in enhanced oil recovery.

For 2010, the Company's capital expenditures included $179 million for abandonment expenditures (2009 – $48 million; 2008 – $38 million).

The Company's estimated undiscounted ARO at December 31, 2010 was as follows:

Estimated ARO, undiscounted ($ millions)	2010	2009
North America, Exploration and Production	$ **4,125**	$ 3,346
North America, Oil Sands Mining and Upgrading	**1,479**	1,485
North Sea	**1,396**	1,522
Offshore West Africa	**232**	253
	7,232	6,606
North Sea PRT recovery	**(423)**	(568)
	$ **6,809**	$ 6,038

The estimate of ARO was based on estimates of future costs to abandon and restore wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $423 million (2009 – $568 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $6,809 million (2009 – $6,038 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants.

In the province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO_2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO_2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that may likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery, and participation in an industry initiative to promote an integrated CO_2 capture and storage network.

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

EXPLORATION AND PRODUCTION PROPERTY, PLANT AND EQUIPMENT / DEPLETION, DEPRECIATION AND AMORTIZATION

Under Canadian GAAP, the Company follows the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by CICA Accounting Guideline 16 ("AcG 16"). Accordingly, all costs relating to the exploration for and development of crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than constant prices and costs as required by the SEC for US GAAP purposes.

Under Canadian GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved plus probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. At December 31, 2010, a pre-tax ceiling test impairment of $726 million (2009 – $115 million) was recognized under Canadian GAAP related to the Olowi Field in Offshore Gabon. As net revenues exceeded capitalized costs for all other cost centres, no other impairments were required under Canadian GAAP. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs using the average first-day-of-the-month price during the previous 12-month period and costs as at the balance sheet date and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test in the current year would not have resulted in the recognition of any incremental after-tax ceiling test impairment (2009 – incremental ceiling test impairment of $815 million) under US GAAP.

The alternate acceptable method of accounting for Exploration and Production properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method, cost centres are defined based on reserve pools rather than by country. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

CRUDE OIL AND NATURAL GAS RESERVES

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

ASSET RETIREMENT OBLIGATIONS

Under CICA Handbook Section 3110, "Asset Retirement Obligations", the Company is required to recognize a liability for the future retirement obligations associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.6%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the retirement cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. changing income tax rates) and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

PURCHASE PRICE ALLOCATIONS

The purchase prices of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgments associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2010, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2010, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2010 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems 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.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt IFRS as promulgated by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project was broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS;
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline;
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS;
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education; and
- Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has substantially completed its IFRS conversion project. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. A summary of the significant differences identified is included below. As certain IFRS standards may change during 2011, the Company may be required to adopt additional new and/or amended accounting standards in the preparation of its December 31, 2011 consolidated financial statements prepared in accordance with IFRS.

The Company has identified, developed and tested accounting and reporting systems and processes to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are complete and implemented.

SUMMARY OF IDENTIFIED IFRS ACCOUNTING POLICY DIFFERENCES

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company followed the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by AcG16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre;
- Exploration and evaluation costs are initially capitalized as exploration and evaluation assets. In areas where the Company has existing operations, costs associated with reserves that are found to be technically feasible and commercially viable will be transferred to PP&E. If technically feasible and commercially viable reserves are not established in an area and if no further activity is planned in that area, the costs are expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired;
- PP&E for producing properties is depleted at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis;
- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is not required; and
- Impairment of PP&E is tested at a cash generating unit level (the lowest level at which cash inflows can be separately identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company has adopted this transition exemption. After initial adoption, future impairment charges may be reversed.

Asset Retirement Obligations
Canadian GAAP accounting requirements for asset retirement obligations ("ARO") are discussed in the "Critical Accounting Estimates" section of this MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the increase in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the increase is adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation
Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company has utilized the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated. On transition to IFRS, the increase in stock-based compensation liability must be recorded in retained earnings.

Petroleum Revenue Tax
Under Canadian GAAP, the liability for the UK PRT is estimated using proved plus probable reserves and future prices and costs, and apportioned to accounting periods over the life of the field on the basis of total estimated future operating income. Under IFRS, the PRT liability is estimated using the balance sheet method in accordance with IAS 12 "Income Taxes", where the liability is based on temporary differences in balance sheet assets and liabilities versus their tax basis. On transition to IFRS, the increase in PRT liability must be recorded in retained earnings.

Income Taxes
Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas. On transition to IFRS, the decrease in the net future income tax liability must be recorded in retained earnings.

Other IFRS 1 Exemptions
The Company has adopted the following IFRS 1 transition exemptions:

- The Company has elected to reset the foreign currency translation adjustment to $nil by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.
- The Company has adopted the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

IFRS Transitional Impacts
Giving effect to the above-noted transitional impacts, the Company estimates that on adoption of IFRS, total Shareholders' Equity as at January 1, 2010 decreased by less than 4% compared to the balance previously determined under Canadian GAAP, resulting in a marginal increase in the Company's reported debt to book capitalization to 34% from 33%. After the adoption of IFRS, the Company expects that 2010 net earnings decreased by an amount estimated to be between $100 million to $200 million, primarily due to higher depletion, depreciation and amortization, offset by lower UK PRT expense. Further, on adoption of IFRS, the Company does not anticipate any significant differences in cash flow from operations as would have been previously reported. Readers are cautioned that these estimates are subject to change, should underlying IFRS standards and/or the interpretations thereof be revised, prior to the final release of the Company's December 31, 2011 annual consolidated financial statements.

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas. The Company expects production levels in 2011 to average between 385,000 bbl/d and 427,000 bbl/d of crude oil and NGLs and between 1,177 MMcf/d and 1,246 MMcf/d of natural gas.

Capital expenditures in 2011 are currently expected to be as follows:

($ millions)		2011 Guidance
Exploration and Production		
North America natural gas	$	600
North America crude oil and NGLs		1,895
North America bitumen (thermal oil)		
Primrose and future		830
Kirby Phase 1		515
Redwater Upgrading and Refining		340
North Sea		370
Offshore West Africa		135
Property acquisitions, dispositions and midstream		350
	$	5,035
Oils Sands Mining and Upgrading		
Sustaining and reclamation capital	$	220
Project capital		
Reliability – Tranche 2		370
Directive 74 and Technology		130
Phase 2A		200 – 230
Phase 2B		10 – 295
Phase 3		90 – 150
Phase 4		0 – 25
Total capital projects	$	800 – 1,200
Capitalized interest and other costs	$	100
	$	1,120 – 1,520
Total	$	6,155 – 6,555

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2011 Guidance
Targeting natural gas	72
Targeting crude oil	1,190
Stratigraphic test / service wells – Exploration and Production	520
Stratigraphic test wells – Oil Sands Mining and Upgrading	280
Total	2,062

NORTH AMERICA NATURAL GAS

The 2011 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2011 Guidance
Coal bed methane and shallow natural gas	4
Conventional natural gas	24
Cardium natural gas	4
Deep natural gas	39
Foothills natural gas	1
Total	72

NORTH AMERICA CRUDE OIL AND NGLS

The 2011 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2011 Guidance
Primary heavy crude oil	791
Bitumen (thermal oil)	217
Light and medium crude oil	138
Pelican Lake heavy crude oil	40
Total	1,186

OIL SANDS MINING AND UPGRADING

Construction and commissioning of the third Ore Preparation Plant, along with the associated hydro-transport pipeline is on schedule for 2011. Engineering work as originally targeted for 2011 also continues on schedule. The Company is targeting additional cost estimate information for the Horizon expansion to be complete in the second quarter of 2011.

NORTH SEA

During 2011, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

OFFSHORE WEST AFRICA

During 2011, the majority of capital expenditures will be incurred on drilling and completions.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2010, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	**Cash flow from operations** (per common share, basic)	**Net earnings** ($ millions)	**Net earnings** (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Including financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 34	$ 0.03	$ 25	$ 0.02
Including financial derivatives	$ 38	$ 0.04	$ 29	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 175	$ 0.16	$ 104	$ 0.10
Natural gas – 10 MMcf/d	$ 9	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 101 – 103	$ 0.09	$ 40 – 41	$ 0.04
Interest rate change – 1%	$ 9	$ 0.01	$ 9	$ 0.01

(1) For details of financial instruments in place, refer to note 12 to the Company's consolidated financial statements as at December 31, 2010.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**252,450**	**275,584**	**267,177**	**286,698**	**270,562**	234,523	243,826
North America – Oil Sands Mining and Upgrading	**86,995**	**99,950**	**83,809**	**92,730**	**90,867**	50,250	–
North Sea	**36,879**	**37,669**	**27,045**	**31,701**	**33,292**	37,761	45,274
Offshore West Africa	**29,942**	**29,842**	**33,554**	**27,706**	**30,264**	32,929	26,567
Total	**406,266**	**443,045**	**411,585**	**438,835**	**424,985**	355,463	315,667
Natural gas (MMcf/d)							
North America	**1,193**	**1,219**	**1,234**	**1,223**	**1,217**	1,287	1,472
North Sea	**15**	**9**	**8**	**9**	**10**	10	10
Offshore West Africa	**18**	**9**	**16**	**20**	**16**	18	13
Total	**1,226**	**1,237**	**1,258**	**1,252**	**1,243**	1,315	1,495
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**451,269**	**478,770**	**472,850**	**490,470**	**473,447**	449,054	489,081
North America – Oil Sands Mining and Upgrading	**86,995**	**99,950**	**83,809**	**92,730**	**90,867**	50,250	–
North Sea	**39,352**	**39,175**	**28,321**	**33,186**	**34,973**	39,444	46,956
Offshore West Africa	**32,940**	**31,300**	**36,304**	**31,055**	**32,904**	35,982	28,808
Total	**610,556**	**649,195**	**621,284**	**647,441**	**632,191**	574,730	564,845

PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
Sales price (2)	**$ 68.76**	**$ 63.62**	**$ 63.21**	**$ 67.74**	**$ 65.81**	$ 57.68	$ 82.41
Royalties	**10.08**	**8.95**	**9.05**	**12.14**	**10.09**	6.73	10.48
Production expense	**14.56**	**13.19**	**15.37**	**13.59**	**14.16**	15.92	16.26
Netback	**$ 44.12**	**$ 41.48**	**$ 38.79**	**$ 42.01**	**$ 41.56**	$ 35.03	$ 55.67
Natural gas ($/Mcf)							
Sales price (2)	**$ 5.19**	**$ 3.86**	**$ 3.75**	**$ 3.56**	**$ 4.08**	$ 4.53	$ 8.39
Royalties (3)	**0.41**	**0.25**	**0.11**	**0.07**	**0.20**	0.32	1.46
Production expense	**1.20**	**1.05**	**1.05**	**1.05**	**1.09**	1.08	1.02
Netback	**$ 3.58**	**$ 2.56**	**$ 2.59**	**$ 2.44**	**$ 2.79**	$ 3.13	$ 5.91
Barrels of oil equivalent ($/BOE)							
Sales price (2)	**$ 53.88**	**$ 47.97**	**$ 47.44**	**$ 50.41**	**$ 49.90**	$ 44.87	$ 68.62
Royalties	**7.07**	**6.10**	**5.83**	**7.83**	**6.72**	4.72	9.78
Production expense	**11.67**	**10.55**	**11.89**	**10.91**	**11.25**	11.98	11.79
Netback	**$ 35.14**	**$ 31.32**	**$ 29.72**	**$ 31.67**	**$ 31.93**	$ 28.17	$ 47.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
SCO sales price (2)	**$ 78.76**	**$ 75.97**	**$ 75.31**	**$ 81.51**	**$ 77.89**	$ 70.83	$ –
Bitumen royalties (3)	**2.83**	**2.69**	**2.57**	**2.77**	**2.72**	2.15	–
Production expense	**43.12**	**32.27**	**34.35**	**36.13**	**36.36**	39.89	–
Netback	**$ 32.81**	**$ 41.01**	**$ 38.39**	**$ 42.61**	**$ 38.81**	$ 28.79	$ –

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2010	2009(1)
TSX – C$						
Trading volume (thousands)					**661,832**	1,040,320
Share Price ($/share)						
High	**$ 38.70**	**$ 40.08**	**$ 37.35**	**$ 45.00**	**$ 45.00**	$ 39.50
Low	**$ 33.81**	**$ 33.09**	**$ 31.97**	**$ 35.80**	**$ 31.97**	$ 17.93
Close	**$ 37.59**	**$ 35.33**	**$ 35.59**	**$ 44.35**	**$ 44.35**	$ 38.00
Market capitalization as at December 31 ($ millions)					**$ 48,379**	$ 41,217
Shares outstanding (thousands)					**1,090,848**	1,084,654
NYSE – US$						
Trading volume (thousands)					**759,327**	1,514,614
Share Price ($/share)						
High	**$ 37.33**	**$ 40.12**	**$ 36.47**	**$ 44.77**	**$ 44.77**	$ 38.26
Low	**$ 31.42**	**$ 30.51**	**$ 30.00**	**$ 34.64**	**$ 30.00**	$ 13.85
Close	**$ 37.02**	**$ 33.23**	**$ 34.60**	**$ 44.42**	**$ 44.42**	$ 35.98
Market capitalization as at December 31 ($ millions)					**$ 48,455**	$ 39,020
Shares outstanding (thousands)					**1,090,848**	1,084,654

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

Management's Report

The accompanying consolidated financial statements and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2010; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2010.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

STEVE W. LAUT
President

DOUGLAS A. PROLL, CA
Chief Financial Officer &
Senior Vice-President, Finance

RANDALL S. DAVIS, CA
Vice-President, Finance &
Accounting

Calgary, Alberta, Canada
March 1, 2011

Management's Assessment of Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13(a)–15(f) and 15d–15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2010. Management recognizes that all internal control systems have 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.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2010, as stated in their Auditor's Report.

STEVE W. LAUT
President

DOUGLAS A. PROLL, CA
Chief Financial Officer &
Senior Vice-President, Finance

Calgary, Alberta, Canada
March 1, 2011

Independent Auditor's Report

TO THE SHAREHOLDERS OF CANADIAN NATURAL RESOURCES LIMITED

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

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009, and the related consolidated statements of earnings, changes in shareholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2010 and the related notes.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

AUDITOR'S RESPONSIBILITY

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

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

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

OPINION

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

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

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

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

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

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

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

INHERENT LIMITATIONS

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

OPINION

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

PricewaterhouseCoopers LLP

CHARTERED ACCOUNTANTS

Calgary, Alberta, Canada
March 1, 2011

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)		2010		2009
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**22**	$	13
Accounts receivable		**1,481**		1,148
Inventory, prepaids and other		**610**		584
Future income tax (note 7)		**59**		146
		2,172		1,891
Property, plant and equipment (note 4)		**40,472**		39,115
Other long-term assets (note 3)		**25**		18
	$	**42,669**	$	41,024
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**274**	$	240
Accrued liabilities		**2,163**		1,522
Current portion of other long-term liabilities (note 6)		**719**		643
		3,156		2,405
Long-term debt (note 5)		**8,499**		9,658
Other long-term liabilities (note 6)		**2,130**		1,848
Future income tax (note 7)		**7,899**		7,687
		21,684		21,598
SHAREHOLDERS' EQUITY				
Share capital (note 8)		**3,147**		2,834
Retained earnings		**18,005**		16,696
Accumulated other comprehensive loss (note 9)		**(167)**		(104)
		20,985		19,426
	$	**42,669**	$	41,024

Commitments and contingencies (note 13)

Approved by the Board of Directors:

CATHERINE M. BEST
Chair of the Audit Committee and Director

N. MURRAY EDWARDS
Vice-Chairman of the Board of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2010	2009	2008
Revenue	$ **14,322**	$ 11,078	$ 16,173
Less: royalties	**(1,421)**	(936)	(2,017)
Revenue, net of royalties	**12,901**	10,142	14,156
Expenses			
Production	**3,447**	2,987	2,451
Transportation and blending	**1,783**	1,218	1,936
Depletion, depreciation and amortization	**4,036**	2,819	2,683
Asset retirement obligation accretion (note 6)	**107**	90	71
Administration	**210**	181	180
Stock-based compensation expense (recovery) (note 6)	**294**	355	(52)
Interest, net	**449**	410	128
Risk management activities (note 12)	**(121)**	738	(1,230)
Foreign exchange (gain) loss	**(182)**	(631)	718
	10,023	8,167	6,885
Earnings before taxes	**2,878**	1,975	7,271
Taxes other than income tax (note 7)	**119**	106	178
Current income tax expense (note 7)	**698**	388	501
Future income tax expense (recovery) (note 7)	**364**	(99)	1,607
Net earnings	$ **1,697**	$ 1,580	$ 4,985
Net earnings per common share (note 11)			
Basic and diluted	$ **1.56**	$ 1.46	$ 4.61

Consolidated Statements of Shareholders' Equity

For the years ended December 31 (millions of Canadian dollars)	2010	2009	2008
Share capital (note 8)			
Balance – beginning of year	**$ 2,834**	$ 2,768	$ 2,674
Issued upon exercise of stock options	**170**	24	18
Previously recognized liability on stock options exercised for common shares	**149**	42	76
Purchase of common shares under Normal Course Issuer Bid	**(6)**	–	–
Balance – end of year	**3,147**	2,834	2,768
Retained earnings			
Balance – beginning of year	**16,696**	15,344	10,575
Net earnings	**1,697**	1,580	4,985
Purchase of common shares under Normal Course Issuer Bid	**(62)**	–	–
Dividends on common shares (note 8)	**(326)**	(228)	(216)
Balance – end of year	**18,005**	16,696	15,344
Accumulated other comprehensive (loss) income (note 9)			
Balance – beginning of year	**(104)**	262	72
Other comprehensive (loss) income, net of taxes	**(63)**	(366)	190
Balance – end of year	**(167)**	(104)	262
Shareholders' equity	**$ 20,985**	$ 19,426	$ 18,374

Consolidated Statements of Comprehensive Income

For the years ended December 31 (millions of Canadian dollars)	2010	2009	2008
Net earnings	**$ 1,697**	$ 1,580	$ 4,985
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income during the year, net of taxes of $11 million (2009 – $5 million, 2008 – $1 million)	**(24)**	(33)	30
Reclassification to net earnings, net of taxes of $1 million (2009 – $1 million, 2008 – $6 million)	**(4)**	(10)	(12)
	(28)	(43)	18
Foreign currency translation adjustment			
Translation of net investment	**(35)**	(323)	172
Other comprehensive (loss) income, net of taxes	**(63)**	(366)	190
Comprehensive income	**$ 1,634**	$ 1,214	$ 5,175

(D) INVENTORIES

Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Inventories are primarily comprised of crude oil production held for sale.

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

The Company follows the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by Accounting Guideline 16 ("AcG 16") issued by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Directly attributable administrative overhead incurred during the development of certain large capital projects is capitalized until the projects are available for their intended use. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are accounted for separately from the Company's Canadian Exploration and Production costs. Capitalized mining activity costs include property acquisition, construction and development costs. Construction and development costs are capitalized separately to each Phase of Horizon. The construction and development of a particular Phase of Horizon is considered complete once the Phase is available for its intended use. Costs related to major maintenance turnaround activities are capitalized as incurred and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased and depletion, depreciation and amortization of these assets commenced.

Midstream and Other

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets.

(F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during development of the Horizon mine are capitalized to property, plant and equipment. Overburden removal costs incurred during production of the Horizon mine are included in the cost of inventory, unless the overburden removal activity has resulted in a betterment of the mineral property, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(G) CAPITALIZED INTEREST

The Company capitalizes construction period interest based on major qualifying costs incurred and the Company's cost of borrowing. Interest capitalization on a particular project ceases once this project is available for its intended use.

(H) LEASES

Leases that transfer substantially all of the benefits and risks of ownership to the Company are accounted for as capital leases and are recorded as property, plant and equipment with an offsetting liability. All other leases are accounted for as operating leases whereby lease costs are expensed as incurred. Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate.

(I) DEPLETION, DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Exploration and Production

Substantially all costs related to each country-by-country cost centre are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties and major development projects. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended use. Unproved properties and major development projects are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of an unproved property or major development project is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its Exploration and Production properties ("the properties") relative to their recoverable amount ("the ceiling test") for each cost centre at each annual balance sheet date, or more frequently if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, an impairment loss is recognized in depletion and depreciation expense equal to the amount by which the carrying amount of the properties exceeds their fair value. Fair value is calculated as the cash flow from those properties using proved plus probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Oil Sands Mining and Upgrading

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on the estimated proved reserves of Horizon or productive capacity, respectively. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

The Company reviews the carrying amount of Horizon relative to its recoverable amount if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from Horizon assets using proved plus probable reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the assets exceeds fair value. Fair value is calculated as the discounted cash flow from Horizon using proved plus probable reserves and expected future prices and costs.

Midstream and Other

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets when events or circumstances indicate that the carrying amount might not be recoverable. If the carrying amount of the midstream assets exceeds their recoverable amount, an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation. Other capital assets are amortized on a declining balance basis.

(J) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms, gathering systems, and oil sands mining operations and tailings ponds based on current legislation and industry operating practices. The fair values of asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated property, plant and equipment and are amortized to expense through depletion and depreciation over the lives of the respective assets. The fair value of an asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's average credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for changes in the amount or timing of the underlying future cash flows. Actual expenditures are charged against the accumulated asset retirement obligation as incurred.

(K) FOREIGN CURRENCY TRANSLATION

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in accumulated other comprehensive income (loss) in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related assets. Gains or losses on translation of integrated foreign operations and foreign currency balances are included in the consolidated statements of earnings.

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue as reported represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Revenue, net of royalties represents the Company's share after royalty payments to governments and other mineral interest owners.

Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(M) PRODUCTION SHARING CONTRACTS

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

(N) PETROLEUM REVENUE TAX

The Company accounts for the UK petroleum revenue tax ("PRT") over the life of the field. The total future liability or recovery of PRT is estimated using proved plus probable reserves and anticipated future sales prices and costs. The estimated future PRT is then apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Taxable income arising from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. Accordingly, North America current and future income taxes have been provided on the basis of this corporate structure.

(P) STOCK-BASED COMPENSATION PLANS

The Company accounts for stock-based compensation using the intrinsic value method as the Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. A liability for potential cash settlements under the Option Plan is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares, after consideration of an estimated forfeiture rate. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and actual forfeitures, with the net change recognized in net earnings, or capitalized during the construction period in the case of Horizon. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees and any previously recognized liability associated with the stock options are recorded as share capital.

The Company has an employee stock savings plan and a stock bonus plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution. Contributions to the stock bonus plan are recognized as compensation expense over the related vesting period.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: held-for-trading financial assets and financial liabilities; held-to-maturity investments; loans and receivables; available-for-sale financial assets; and other financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Held-for-trading financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. Available-for-sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income, net of tax. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents are classified as held-for-trading and are measured at fair value. Accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities. Although the Company does not intend to trade its derivative financial instruments, risk management assets and liabilities are classified as held-for-trading for accounting purposes.

Financial assets and liabilities are categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized on the consolidated balance sheet at estimated fair value at each balance sheet date. The estimated fair value of derivative financial instruments is determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production and purchases of natural gas in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the commodity is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is de-recognized on the balance sheet and the related long-term debt hedged is no longer revalued for changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash management requirements.The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange loss (gain) when realized. Changes in the fair value of foreign currency forward contracts not designated as hedges are included in risk management activities in consolidated net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not accounted for as a liability are used to purchase common shares at the average market price during the year. The Company's Option Plan described in note 8 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in the calculation of diluted earnings per share. The dilutive effect of other convertible securities is calculated by applying the "if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

(U) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2010. Common share, per common share, and stock option data has been restated to reflect the two-for-one share split in May 2010.

2. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the Canadian Institute of Chartered Accountants' Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of Canadian GAAP effective January 1, 2011.

3. OTHER LONG-TERM ASSETS

	2010	2009
Other	**$ 25**	$ 18

4. PROPERTY, PLANT AND EQUIPMENT

	2010			2009		
	Cost	**Accumulated depletion and depreciation**	**Net**	Cost	Accumulated depletion and depreciation	Net
Exploration and Production						
North America	**$ 43,014**	**$ 18,740**	**$ 24,274**	$ 38,259	$ 16,425	$ 21,834
North Sea	**3,757**	**2,232**	**1,525**	3,879	2,067	1,812
Offshore West Africa	**2,943**	**1,965**	**978**	2,861	978	1,883
Other	**45**	**14**	**31**	42	14	28
Oil Sands Mining and Upgrading	**13,957**	**556**	**13,401**	13,481	186	13,295
Midstream	**291**	**89**	**202**	284	81	203
Head office	**213**	**152**	**61**	200	140	60
	$ 64,220	**$ 23,748**	**$ 40,472**	$ 59,006	$ 19,891	$ 39,115

During the year ended December 31, 2010, the Company capitalized directly attributable administrative costs of $43 million (2009 – $41 million, 2008 – $55 million) in the North Sea and Offshore West Africa, related to exploration and development and $33 million (2009 – $79 million, 2008 – $404 million) in North America, related to Oil Sands Mining and Upgrading.

During the year ended December 31, 2010, the Company capitalized $28 million (2009 – $106 million, 2008 – $481 million) in construction period interest costs related to Oil Sands Mining and Upgrading.

Included in property, plant and equipment are unproved land and major development projects that are not currently subject to depletion or depreciation:

	2010	2009
Exploration and Production		
North America	**$ 2,362**	$ 2,102
North Sea	**–**	4
Offshore West Africa	**–**	666
Other	**31**	28
Oil Sands Mining and Upgrading	**915**	752
	$ 3,308	$ 3,552

The Company has used the following estimated benchmark future prices ("escalated pricing") in its full cost ceiling tests for Exploration and Production properties prepared in accordance with Canadian GAAP, as at December 31, 2010:

	2011	2012	2013	2014	2015	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 88.40	$ 89.14	$ 88.77	$ 88.88	$ 90.22	1.5%
Western Canada Select (C$/bbl)	$ 80.04	$ 80.71	$ 78.48	$ 76.70	$ 77.86	1.5%
Edmonton Par (C$/bbl)	$ 93.08	$ 93.85	$ 93.43	$ 93.54	$ 94.95	1.5%
Edmonton C5+ (C$/bbl)	$ 95.32	$ 96.11	$ 95.68	$ 95.79	$ 97.24	1.5%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 87.15	$ 87.87	$ 87.48	$ 87.58	$ 88.89	1.5%
Natural gas						
North America						
Henry Hub Louisiana (US$/MMBtu)	$ 4.44	$ 5.01	$ 5.32	$ 6.80	$ 6.90	1.5%
AECO (C$/MMBtu)	$ 4.04	$ 4.66	$ 4.99	$ 6.58	$ 6.69	1.5%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.98	$ 4.60	$ 4.93	$ 6.52	$ 6.63	1.5%

At December 31, 2010, Offshore West Africa property, plant and equipment was reduced by a pre-tax ceiling test impairment charge of $726 million (2009 – $115 million). The impairment charge was included in depletion, depreciation and amortization expense.

5. LONG-TERM DEBT

	2010	2009
Canadian dollar denominated debt		
Bank credit facilities		
Bankers' acceptances	**$ 1,436**	$ 1,897
Medium-term notes		
5.50% unsecured debentures due December 17, 2010	**–**	400
4.50% unsecured debentures due January 23, 2013	**400**	400
4.95% unsecured debentures due June 1, 2015	**400**	400
	2,236	3,097
US dollar denominated debt		
US dollar debt securities		
6.70% due July 15, 2011 (US$400 million)	**398**	419
5.45% due October 1, 2012 (US$350 million)	**348**	366
5.15% due February 1, 2013 (US$400 million)	**398**	419
4.90% due December 1, 2014 (US$350 million)	**348**	366
6.00% due August 15, 2016 (US$250 million)	**249**	262
5.70% due May 15, 2017 (US$1,100 million)	**1,094**	1,151
5.90% due February 1, 2018 (US$400 million)	**398**	419
7.20% due January 15, 2032 (US$400 million)	**398**	419
6.45% due June 30, 2033 (US$350 million)	**348**	366
5.85% due February 1, 2035 (US$350 million)	**348**	366
6.50% due February 15, 2037 (US$450 million)	**447**	471
6.25% due March 15, 2038 (US$1,100 million)	**1,094**	1,151
6.75% due February 1, 2039 (US$400 million)	**398**	419
Less – original issue discount (1)	**(20)**	(22)
	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	**61**	38
	6,307	6,610
Long-term debt before transaction costs	**8,543**	9,707
Less: transaction costs (1)(3)	**(44)**	(49)
	$ 8,499	$ 9,658

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.
(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.
(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

BANK CREDIT FACILITIES

As at December 31, 2010, the Company had in place unsecured bank credit facilities of $3,953 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

During 2009, the Company repaid the remaining $2,350 million outstanding on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility.

During 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2010, was 1.5% (2009 – 0.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $283 million, including $205 million related to Horizon, were outstanding at December 31, 2010. Subsequent to December 31, 2010 the financial guarantee related to Horizon was reduced to $190 million.

MEDIUM-TERM NOTES

During 2010, the Company repaid $400 million of medium-term notes bearing interest at 5.50%.

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

US DOLLAR DEBT SECURITIES

During 2010, the Company unwound the interest rate swaps previously designated as a fair value hedge of US$350 million of 4.90% unsecured notes due December 2014. Accordingly, the Company ceased revaluing the related debt for subsequent changes in fair value from the date of unwind. The fair value adjustment of $55 million at the date of unwind is being amortized to interest expense over the remaining term of the debt.

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2011	$ 398
2012	$ 348
2013	$ 798
2014	$ 348
2015	$ 400
Thereafter	$ 4,774

No debt repayments are reflected in the above table for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities. Should the bank credit facilities not be extended by mutual agreement of the Company and the lenders, the amounts outstanding under these facilities would be due in 2012.

6. OTHER LONG-TERM LIABILITIES

		2010		2009
Asset retirement obligations	$	**1,779**	$	1,610
Stock-based compensation		**516**		392
Risk management (note 12)		**451**		309
Other		**103**		180
		2,849		2,491
Less: current portion		**719**		643
	$	**2,130**	$	1,848

ASSET RETIREMENT OBLIGATIONS

At December 31, 2010, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $7,232 million (2009 – $6,606 million; 2008 – $4,474 million). Payments to settle these asset retirement obligations will occur on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average credit-adjusted risk-free interest rate of 6.6% (2009 – 6.9%; 2008 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

		2010		2009		2008
Balance – beginning of year	$	**1,610**	$	1,064	$	1,074
Liabilities incurred [(1)]		**12**		299		18
Liabilities acquired		**22**		–		3
Liabilities settled		**(179)**		(48)		(38)
Asset retirement obligation accretion		**107**		90		71
Revision of estimates		**240**		276		(156)
Foreign exchange		**(33)**		(71)		92
Balance – end of year	$	**1,779**	$	1,610	$	1,064

(1) During 2009, the Company recognized additional asset retirement obligations related to Oil Sands Mining and Upgrading and Gabon, Offshore West Africa.

STOCK-BASED COMPENSATION

The Company recognizes a liability for potential cash settlements under its Option Plan. The current portion represents the maximum amount of the liability payable within the next 12–month period if all vested options are surrendered for cash settlement.

		2010		2009		2008
Balance – beginning of year	$	**392**	$	171	$	529
Stock-based compensation expense (recovery)		**294**		355		(52)
Cash payment for options surrendered		**(45)**		(94)		(207)
Transferred to common shares		**(149)**		(42)		(76)
Capitalized (recovery) to Oil Sands Mining and Upgrading		**24**		2		(23)
Balance – end of year		**516**		392		171
Less: current portion		**472**		365		159
	$	**44**	$	27	$	12

7. TAXES

TAXES OTHER THAN INCOME TAX

		2010		2009		2008
Current PRT expense	**$**	**69**	$	70	$	210
Deferred PRT expense (recovery)		**28**		15		(67)
Provincial capital taxes and surcharges		**22**		21		35
	$	**119**	$	106	$	178

INCOME TAX

The provision for income tax is as follows:

		2010		2009		2008
Current income tax – North America	**$**	**432**	$	28	$	33
Current income tax – North Sea		**203**		278		340
Current income tax – Offshore West Africa		**63**		82		128
Current income tax expense		**698**		388		501
Future income tax expense (recovery)		**364**		(99)		1,607
Income tax expense	**$**	**1,062**	$	289	$	2,108

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

		2010		2009		2008
Canadian statutory income tax rate		**28.1%**		29.1%		29.8%
Income tax provision at statutory rate	**$**	**809**	$	576	$	2,166
Effect on income taxes of:						
Deductible UK PRT		**(49)**		(43)		(72)
Foreign and domestic tax rate differentials		**1**		(127)		(5)
North America income tax rate and other legislative changes		**–**		(19)		(19)
Côte d'Ivoire income tax rate changes		**–**		–		(22)
Non-taxable portion of foreign exchange (gain) loss		**(17)**		(92)		127
Stock options exercised in shares		**168**		27		6
Non-deductible Offshore West Africa impairment charge		**129**		14		–
Other		**21**		(47)		(73)
Income tax expense	**$**	**1,062**	$	289	$	2,108

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

		2010		2009
Future income tax liabilities				
Property, plant and equipment	**$**	**7,525**	$	6,992
Timing of partnership items		**988**		1,127
Unrealized foreign exchange gain on long-term debt		**194**		152
Other		**–**		31
Future income tax assets				
Asset retirement obligations		**(525)**		(499)
Loss carryforwards for income tax		**(148)**		(84)
Stock-based compensation		**–**		(83)
Unrealized risk management activities		**(92)**		(69)
Other		**(105)**		–
Deferred PRT		**3**		(26)
Net future income tax liability		**7,840**		7,541
Less: current portion of future income tax asset		**(59)**		(146)
Future income tax liability	**$**	**7,899**	$	7,687

During 2010, future income tax expense included a charge of $83 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

During 2009, enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

During 2008, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and approximately $22 million in Côte d'Ivoire.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that might ultimately arise from these reassessments will be material.

8. SHARE CAPITAL

AUTHORIZED

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

ISSUED

	2010			2009		
Common shares	**Number of shares** (thousands) (1)		**Amount**	Number of shares (thousands) (1)		Amount
Balance – beginning of year	**1,084,654**	**$**	**2,834**	1,081,982	$	2,768
Issued upon exercise of stock options	**8,208**		**170**	2,672		24
Previously recognized liability on stock options exercised for common shares	**–**		**149**	–		42
Cancellation of common shares	**(14)**		**–**	–		–
Purchase of common shares under Normal Course Issuer Bid	**(2,000)**		**(6)**	–		–
Balance – end of year	**1,090,848**	**$**	**3,147**	1,084,654	$	2,834

(1) Restated to reflect two-for-one common share split in May 2010.

DIVIDEND POLICY

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 1, 2011, the Board of Directors set the Company's regular quarterly dividend at $0.09 per common share (2010 – $0.075 per common share, 2009 – $0.053 per common share).

NORMAL COURSE ISSUER BID

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. During 2010, the Company purchased 2,000,000 common shares for cancellation at an average price of $33.77 per common share, for a total cost of $68 million. Retained earnings was reduced by $62 million, representing the excess of the purchase price of the common shares over their average carrying value. The Company did not purchase any common shares for cancellation in 2009 and 2008.

SHARE SPLIT

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010 with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

STOCK OPTIONS

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or 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 of surrender of the option.

The following table summarizes information relating to stock options outstanding at December 31, 2010 and 2009:

	2010			2009		
	Stock options (thousands) (1)		**Weighted average exercise price** (1)	Stock options (thousands) (1)		Weighted average exercise price (1)
Outstanding – beginning of year	**64,211**	**$**	**29.27**	61,924	$	25.97
Granted	**16,168**	**$**	**40.68**	13,472	$	33.96
Surrendered for cash settlement	**(2,741)**	**$**	**21.00**	(5,666)	$	13.66
Exercised for common shares	**(8,208)**	**$**	**20.66**	(2,672)	$	9.00
Forfeited	**(2,586)**	**$**	**32.30**	(2,847)	$	29.78
Outstanding – end of year	**66,844**	**$**	**33.31**	64,211	$	29.27
Exercisable – end of year	**23,668**	**$**	**30.64**	21,937	$	26.95

(1) Restated to reflect two-for-one common share split in May 2010.

The range of exercise prices of stock options outstanding and exercisable at December 31, 2010 was as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$12.34 – $14.99	69	0.05	$	12.69	69	$	12.69
$15.00 – $19.99	249	0.31	$	16.54	244	$	16.54
$20.00 – $24.99	11,599	3.09	$	23.19	4,171	$	23.10
$25.00 – $29.99	6,589	0.99	$	28.94	4,546	$	28.85
$30.00 – $34.99	21,055	3.10	$	33.00	7,979	$	31.70
$35.00 – $39.99	14,615	3.00	$	36.02	6,267	$	35.36
$40.00 – $44.99	11,287	5.05	$	42.24	–	$	–
$45.00 – $46.25	1,381	3.53	$	46.25	392	$	46.25
	66,844	3.20	$	33.31	23,668	$	30.64

9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss, net of taxes, were as follows:

		2010		2009
Derivative financial instruments designated as cash flow hedges	**$**	**48**	$	76
Foreign currency translation adjustment		**(215)**		(180)
	$	**(167)**	$	(104)

During the next 12 months, $40 million is expected to be reclassified from accumulated other comprehensive loss, reducing net earnings.

10. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2010, the ratio is below the target range at 29%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	2010	2009
Long-term debt	**$ 8,499**	$ 9,658
Total shareholders' equity	**$ 20,985**	$ 19,426
Debt to book capitalization	**29%**	33%

11. NET EARNINGS PER COMMON SHARE

	2010	2009	2008
Weighted average common shares outstanding – basic and diluted (thousands of shares) [1]	**1,088,096**	1,083,850	1,081,294
Net earnings – basic and diluted	**$ 1,697**	$ 1,580	$ 4,985
Net earnings per common share – basic and diluted [1]	**$ 1.56**	$ 1.46	$ 4.61

(1) Restated to reflect two-for-one common share split in May 2010.

12. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	2010		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 22**	**$ –**
Accounts receivable	**1,481**	**–**	**–**
Accounts payable	**–**	**–**	**(274)**
Accrued liabilities	**–**	**–**	**(2,163)**
Other long-term liabilities	**–**	**(451)**	**(91)**
Long-term debt	**–**	**–**	**(8,499)**
	$ 1,481	**$ (429)**	**$ (11,027)**

	2009		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 13	$ –
Accounts receivable	1,148	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$ 1,148	$ (296)	$ (11,587)

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	2010		
	Carrying value	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (451)**	**$ –**	**$ (451)**
Fixed-rate long-term debt(2) (3)	**(7,063)**	**(7,835)**	**–**
	$ (7,514)	**$ (7,835)**	**$ (451)**

	2009		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (309)	$ –	$ (309)
Fixed-rate long-term debt(2) (3)	(7,761)	(8,212)	–
	$ (8,070)	$ (8,212)	$ (309)

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).
(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.
(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

RISK MANAGEMENT

The changes in estimated fair values of derivative financial instruments included in the net risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	**2010 Risk management mark-to-market**	2009 Risk management mark-to-market
Balance – beginning of year	**$ (309)**	$ 2,119
Net cost of outstanding put options	**106**	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**25**	(1,991)
Interest expense	**30**	(25)
Foreign exchange	**(101)**	(338)
Other comprehensive income	**(41)**	(78)
Settlement of interest rate swaps and other	**(55)**	4
	(345)	(309)
Add: put premium financing obligations (1)	**(106)**	–
Balance – end of year	**(451)**	(309)
Less: current portion	**(222)**	(182)
	$ (229)	$ (127)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net (gains) losses from risk management activities for the years ended December 31 were as follows:

	2010	2009	2008
Net realized risk management (gain) loss	**$ (96)**	$ (1,253)	$ 1,860
Net unrealized risk management (gain) loss	**(25)**	1,991	(3,090)
	$ (121)	$ 738	$ (1,230)

FINANCIAL RISK FACTORS

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2010, the Company had the following derivative financial instruments outstanding to manage its commodity price exposures:

i) Sales Contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars	Jan 2011 – Dec 2011	50,000 bbl/d	US$70.00 – US$102.23	WTI
Crude oil puts[1]	Jan 2011 – Dec 2011	100,000 bbl/d	US$70.00	WTI

(1) Crude oil put options have a cost of US$106 million.

ii) Purchase Contracts

	Remaining term	Volume	Weighted average fixed rate	Floating index
Natural gas				
Swaps – floating to fixed	Jan 2011 – Dec 2011	125,000 GJ/d	C$4.87	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designed as hedges as at December 31, 2010 were classified as cash flow hedges.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate [1][2]				
Swaps – floating to fixed	Jan 2011 – Feb 2012	C$200	1.4475%	3 month CDOR [3]

(1) During 2010, the Company unwound US$350 million of 4.9% interest rate swaps for proceeds of US$54 million.
(2) During 2010, the Company unwound C$300 million of 1.0680% interest rate swaps for nominal consideration.
(3) Canadian Dealer Offered Rate.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2010, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps [1]	Jan 2011 – Jul 2011	US$150	0.999	6.70%	7.70%
	Jan 2011 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2011 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2011 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to December 31, 2010, the Company entered into cross currency swap contracts for US$50 million with an exchange rate of $0.994 (US$/C$) and average interest rates of 6.70% (US$) and 7.88% (C$) for the period January to July 2011.

All cross currency swap derivative financial instruments designated as hedges at December 31, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2010, the Company had US$1,162 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2010, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2010	
	Impact on net earnings	**Impact on other comprehensive income**
Commodity price risk		
Increase WTI US$1.00/bbl	$ (7)	$ –
Decrease WTI US$1.00/bbl	$ 7	$ –
Increase AECO C$0.10/Mcf	$ –	$ 3
Decrease AECO C$0.10/Mcf	$ –	$ (3)
Interest rate risk		
Increase interest rate 1%	$ (8)	$ 22
Decrease interest rate 1%	$ 8	$ (31)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (27)	$ –
Decrease exchange rate by US$0.01	$ 27	$ –

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2010, substantially all of the Company's accounts receivables were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2010, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2009 – $7 million).

c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 274	$ –	$ –	$ –
Accrued liabilities	$ 2,163	$ –	$ –	$ –
Risk management	$ 222	$ 32	$ 96	$ 101
Other long-term liabilities	$ 25	$ 25	$ 41	$ –
Long-term debt [1]	$ 398	$ 348	$ 1,546	$ 4,774

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating leases	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations [1]	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2010	2009	2008
Changes in non-cash working capital			
Accounts receivable, inventory, prepaids and other	**$ (340)**	$ (276)	$ 111
Accounts payable	**37**	(151)	(4)
Accrued liabilities	**576**	(429)	(15)
Net changes in non-cash working capital	**$ 273**	$ (856)	$ 92
Relating to:			
Operating activities	**$ 149**	$ (235)	$ (189)
Financing activities	**(5)**	(12)	46
Investing activities	**129**	(609)	235
	$ 273	$ (856)	$ 92

Other cash flow information:	**2010**	2009	2008
Interest paid	**$ 471**	$ 516	$ 574
Taxes other than income tax paid	**$ 102**	$ 52	$ 300
Current income tax paid	**$ 111**	$ 216	$ 258

15. SEGMENTED INFORMATION

The Company's Exploration and Production activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

The Company's Oil Sands Mining and Upgrading is a separate segment from Exploration and Production activities as the bitumen is recovered through mining operations.

	Exploration and Production											
	North America			North Sea			Offshore West Africa			Total		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Segmented revenue	**$ 9,713**	$ 7,973	$13,496	**$ 1,058**	$ 961	$ 1,769	**$ 884**	$ 913	$ 944	**$11,655**	$ 9,847	$16,209
Less: royalties	**(1,267)**	(825)	(1,876)	**(2)**	(2)	(4)	**(62)**	(81)	(143)	**(1,331)**	(908)	(2,023)
Segmented Revenue, net of royalties	**8,446**	7,148	11,620	**1,056**	959	1,765	**822**	832	801	**10,324**	8,939	14,186
Segmented expenses												
Production	**1,675**	1,748	1,881	**385**	376	457	**167**	179	102	**2,227**	2,303	2,440
Transportation and blending	**1,761**	1,213	1,975	**8**	8	10	**1**	1	1	**1,770**	1,222	1,986
Depletion, depreciation and amortization	**2,336**	2,060	2,236	**303**	261	317	**1,023**	335	132	**3,662**	2,656	2,685
Asset retirement obligation accretion	**46**	41	42	**33**	24	27	**6**	4	2	**85**	69	71
Realized risk management activities	**(96)**	(880)	1,861	**–**	(373)	(1)	**–**	–	–	**(96)**	(1,253)	1,860
Total segmented expenses	**5,722**	4,182	7,995	**729**	296	810	**1,197**	519	237	**7,648**	4,997	9,042
Segmented earnings (loss) before the following	**$ 2,724**	$ 2,966	$ 3,625	**$ 327**	$ 663	$ 955	**$ (375)**	$ 313	$ 564	**$ 2,676**	$ 3,942	$ 5,144
Non–segmented expenses												
Administration												
Stock-based compensation expense (recovery)												
Interest, net												
Unrealized risk management activities												
Foreign exchange (gain) loss												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax expense (recovery)												
Net earnings												

Midstream activities include the Company's pipeline operations and an electricity co-generation system. Activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation, electricity charges and natural gas sales.

Oil Sands Mining and Upgrading			**Midstream**			**Inter–segment elimination and other**			**Total**		
2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
$ 2,649	$ 1,253	$ –	**$ 79**	$ 72	$ 77	**$ (61)**	$ (94)	$ (113)	**$14,322**	$11,078	$16,173
(90)	(36)	–	**–**	–	–	**–**	8	6	**(1,421)**	(936)	(2,017)
2,559	1,217	–	**79**	72	77	**(61)**	(86)	(107)	**12,901**	10,142	14,156
1,208	683	–	**22**	19	25	**(10)**	(18)	(14)	**3,447**	2,987	2,451
61	41	–	**–**	–	–	**(48)**	(45)	(50)	**1,783**	1,218	1,936
366	187	–	**8**	9	8	**–**	(33)	(10)	**4,036**	2,819	2,683
22	21	–	**–**	–	–	**–**	–	–	**107**	90	71
–	–	–	**–**	–	–	**–**	–	–	**(96)**	(1,253)	1,860
1,657	932	–	**30**	28	33	**(58)**	(96)	(74)	**9,277**	5,861	9,001
$ 902	$ 285	$ –	**$ 49**	$ 44	$ 44	**$ (3)**	$ 10	$ (33)	**3,624**	4,281	5,155
									210	181	180
									294	355	(52)
									449	410	128
									(25)	1,991	(3,090)
									(182)	(631)	718
									746	2,306	(2,116)
									2,878	1,975	7,271
									119	106	178
									698	388	501
									364	(99)	1,607
									$ 1,697	$ 1,580	$ 4,985

CAPITAL EXPENDITURES

	2010			2009		
	Net expenditures	**Non cash and fair value changes (1)**	**Capitalized costs**	Net expenditures	Non cash and fair value changes (1)	Capitalized costs
Exploration and Production						
North America	**$ 4,369**	**$ 386**	**$ 4,755**	$ 1,663	$ 65	$ 1,728
North Sea	**149**	**(41)**	**108**	168	146	314
Offshore West Africa	**246**	**(10)**	**236**	544	111	655
Other	**3**	**–**	**3**	2	–	2
	4,767	**335**	**5,102**	2,377	322	2,699
Oil Sands Mining and Upgrading (2)	**535**	**(59)**	**476**	553	355	908
Midstream	**7**	**–**	**7**	6	–	6
Head office	**18**	**–**	**18**	13	–	13
	$ 5,327	**$ 276**	**$ 5,603**	$ 2,949	$ 677	$ 3,626

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

SEGMENTED ASSETS

	2010	2009
Exploration and Production		
North America	**$ 25,499**	$ 22,994
North Sea	**1,674**	1,968
Offshore West Africa	**1,186**	2,033
Other	**46**	42
Oil Sands Mining and Upgrading	**13,865**	13,621
Midstream	**338**	306
Head office	**61**	60
	$ 42,669	$ 41,024

16. SUBSEQUENT EVENTS

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except as noted below. Certain differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2010	2009	2008
Net earnings – Canadian GAAP		$ 1,697	$ 1,580	$ 4,985
Adjustments				
Depletion, net of taxes of $365 million (2009 – $7 million, 2008 – $2,503 million)	(A,B,C,D)	1,128	(273)	(6,169)
Stock-based compensation, net of taxes of $107 million (2009 – $51 million, 2008 – $32 million)	(B)	(41)	(154)	(76)
Future income taxes	(F)	–	–	234
Net earnings (loss) – US GAAP		$ 2,784	$ 1,153	$ (1,026)
Net earnings (loss) – US GAAP per common share [1]				
Basic		$ 2.56	$ 1.06	$ (0.95)
Diluted	(E)	$ 2.54	$ 1.06	$ (0.95)

(1) Restated to reflect two-for-one common share split in May 2010.

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)	2010	2009	2008
Comprehensive income – Canadian GAAP	$ 1,634	$ 1,214	$ 5,175
US GAAP earnings adjustments	1,087	(427)	(6,011)
Comprehensive income (loss) – US GAAP	$ 2,721	$ 787	$ (836)

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

		2010		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$ 2,172	$ –	$ 2,172
Property, plant and equipment	(A,B,C,D)	40,472	(7,324)	33,148
Other long-term assets	(G)	25	44	69
		$ 42,669	$ (7,280)	$ 35,389
Current liabilities	(B)	$ 3,156	$ 354	$ 3,510
Long-term debt	(G)	8,499	44	8,543
Other long-term liabilities	(B)	2,130	9	2,139
Future income tax	(A,B,C,D)	7,899	(2,105)	5,794
Share capital		3,147	–	3,147
Retained earnings		18,005	(5,582)	12,423
Accumulated other comprehensive income		(167)	–	(167)
		$ 42,669	$ (7,280)	$ 35,389

		2009		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$ 1,891	$ 103	$ 1,994
Property, plant and equipment	(A,B,C,D)	39,115	(8,824)	30,291
Other long-term assets	(G)	18	49	67
		$ 41,024	$ (8,672)	$ 32,352
Current liabilities	(B)	$ 2,405	$ 387	$ 2,792
Long-term debt	(G)	9,658	49	9,707
Other long-term liabilities	(B)	1,848	35	1,883
Future income tax	(A,B,C,D)	7,687	(2,474)	5,213
Share capital		2,834	–	2,834
Retained earnings		16,696	(6,669)	10,027
Accumulated other comprehensive income		(104)	–	(104)
		$ 41,024	$ (8,672)	$ 32,352

Notes:

(A) Under Canadian full cost accounting guidance, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved plus probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(I). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date, and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. In addition, beginning in 2009, the Company's Oil Sands Mining and Upgrading activities would have been included in the Company's US GAAP full cost oil and gas cost centre for Canada for ceiling test purposes. These differences in applying the ceiling test to current and prior years would have resulted in the recognition of ceiling test impairments under US GAAP, which would have reduced property, plant and equipment by $8,396 million in 2010 (2009 – $8,951 million, 2008 – $8,697 million).

For the year ended December 31, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $815 million, 2008 – decreased by $6,164 million), net of income taxes of $24 million (2009 – $178 million, 2008 – $2,501 million) to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $359 million (2009 – $551 million, 2008 – $3 million), net of income taxes of $154 million (2009 – $188 million, 2008 – $1 million) to reflect the impact of lower depletion charges.

During 2009, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Topic 932 "Extractive Activities – Oil and Gas" (a summary of the requirements included in Regulation S-X). These revisions impacted the reserves used in the Company's calculation of the ceiling test under US GAAP at December 31, 2009 and 2010 and the calculation of depletion in 2010. In addition, oil and gas activities were determined based on the end product, rather than the method of extraction. As a result, the Company's Oil Sands Mining and Upgrading operations were included in its full cost oil and gas cost center for Canada. These revisions were effective for filings made on or after January 1, 2010, and were applied prospectively with no retroactive restatement. For the year ended December 31, 2010, US GAAP net earnings would have increased by $708 million, net of income taxes of $237 million, to reflect the impact of lower depletion charges.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement (FASB) Topic 718 "Compensation – Stock Compensation" (previously FAS 123(R)), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $154 million, 2008 – decreased by $76 million), net of income taxes of $nil (2009 – $51 million, 2008 – $32 million) related to the different valuation methodologies. In addition, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil) related to the impact of the change in capitalized stock-based compensation on depletion, depreciation and amortization expenses.

Future income tax expense would have included a charge of $107 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

(C) Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging. The impact of prior year adjustments would have decreased US GAAP net earnings by $3 million for the year ended December 31, 2010 (2009 – $7 million, 2008 – $8 million), net of income taxes of $2 million (2009 and 2008 – $3 million), to reflect the impact of higher depletion charges.

(D) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest ceased and depletion, depreciation and amortization of these assets commenced. For the year ended December 31, 2010, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil).

(E) Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP Topic 260 "Earnings Per Share" (previously FAS 128 "Earnings Per Share"), the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2010, 8 million additional shares would have been included in the calculation of diluted earnings per share for US GAAP (2009 and 2008 – nil additional shares).

(F) Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the year ended December 31, 2008, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(G) Under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $44 million of debt issue costs from long-term debt to deferred charges in 2010 (2009 – $49 million, 2008 – $55 million).

(H) In December 2007, the FASB issued Topic 805 "Business Combinations" (previously FAS 141(R) "Business Combinations"), which replaced FAS 141 effective for fiscal years beginning after December 15, 2009. Topic 805 retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations. The adoption of this standard did not result in a US GAAP reconciling item.

(I) Effective January 1, 2011 the Company will be preparing consolidated financial statements in accordance with IFRS and a reconciliation to US GAAP will not be required. As a result, SAB Topic 11M, "Disclosure of the Impact that Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period" was not provided for 2010.

Supplementary Oil & Gas Information (unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas", and where applicable is reconciled to the financial information prepared in accordance with generally accepted accounting principles in the United States ("US GAAP").

For the year ended December 31, 2010, the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. For years prior to 2010, the Company was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the SEC requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, and future net revenue under forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2010 and 2009, the Company used the 12-month average price, as defined by the SEC as the unweighted average price of the first day of the month within the 12-month period prior to the end of the reporting period. Prior to December 31, 2009, year end prices and costs were used in the reserves estimates. The company has used the following 12-month average benchmark prices to determine its 2010 reserves for SEC requirements.

Crude Oil and NGLs					Natural Gas		
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMbtu)	AECO (C$/MMbtu)	BC Westcoast Station 2 (C$/MMbtu)
79.43	67.40	77.98	79.02	84.43	4.38	4.06	3.92

A foreign exchange rate of US$0.967/C$1.00 was used in the 2010 evaluation.

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains Independent Qualified Reserves Evaluators to evaluate the Company's proved crude oil and natural gas reserves.

- For the years ended December 31, 2010 and 2009, the reports by GLJ Petroleum Consultants Ltd. ("GLJ") covered 100% of the Company's synthetic crude oil reserves. With the inclusion of the non-traditional resources within the definition of "oil and gas producing activities" within the SEC's modernization of oil and gas reporting rules ("Final Rule"), effective January 1, 2010 these reserves volumes are now included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2010, 2009, and 2008, the reports by Sproule Associates Limited and Sproule International Limited (together as "Sproule") covered 100% of the Company's bitumen, crude oil and natural gas liquids and natural gas reserves.
- For the year ended December 31, 2007, the reports by Sproule and Ryder Scott Company covered 100% of the Company's bitumen, crude oil and natural gas liquids and natural gas reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, under the Final Rule, are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, under known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate is the extraction by means not involving a well.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2010, 2009, 2008, and 2007:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil**[(1)]	**Bitumen**[(2)]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore West Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2007				920	310	128	1,358
Extensions and discoveries				51	–	–	51
Improved recovery				17	6	4	27
Purchases of reserves in place				–	–	–	–
Sales of reserves in place				–	–	–	–
Production				(76)	(17)	(8)	(101)
Economic revisions due to prices				28	(81)	8	(45)
Revisions of prior estimates				8	38	10	56
Reserves, December 31, 2008	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Improved recovery	–	8	75	83	–	–	83
SEC reliable technology[(3)]	–	7	–	7	–	–	7
SEC rule transition[(4)]	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027
Extensions and discoveries	**–**	**55**	**9**	**64**	**–**	**–**	**64**
Improved recovery	**–**	**22**	**6**	**28**	**–**	**–**	**28**
Purchases of reserves in place	**–**	**92**	**15**	**107**	**–**	**–**	**107**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**(32)**	**(54)**	**(26)**	**(112)**	**(12)**	**(10)**	**(134)**
Economic revisions due to prices	**(41)**	**(25)**	**–**	**(66)**	**28**	**–**	**(38)**
Revisions of prior estimates	**86**	**93**	**5**	**184**	**1**	**(11)**	**174**
Reserves, December 31, 2010	**1,663**	**878**	**328**	**2,869**	**257**	**102**	**3,228**
Net proved developed reserves							
December 31, 2007				426	240	70	736
December 31, 2008				428	97	107	632
December 31, 2009	1,589	268	204	2,061	94	106	2,261
December 31, 2010	**1,546**	**262**	**240**	**2,048**	**94**	**83**	**2,225**

(1) Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with the SEC's Industry Guide 7. With the SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserves totals.

(2) Bitumen as defined by the SEC, under the Final Rule, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy oil reserves have been classified as bitumen. Prior to December 31, 2009, these reserves would have been classified within the Company's conventional crude oil and NGL totals.

(3) SEC reliable technology accounts for reserves volumes added due to the reserves rule changes.

(4) For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following SCO table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO Reserves	Net proved (MMbbl)
Reserves, December 31, 2008	1,946
Production	(18)
Economic revisions due to prices	(307)
Revisions of prior estimates	29
Reserves, December 31, 2009	1,650

Natural Gas (Bcf)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2007	3,521	81	64	3,666
Extensions and discoveries	140	–	–	140
Improved recovery	52	(1)	6	57
Purchases of reserves in place	77	–	–	77
Sales of reserves in place	(1)	–	–	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008	3,523	67	94	3,684
Extensions and discoveries	92	–	–	92
Improved recovery	11	–	–	11
Purchases of reserves in place	15	–	–	15
Sales of reserves in place	(6)	–	–	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	3,027	67	85	3,179
Extensions and discoveries	**249**	**–**	**–**	**249**
Improved recovery	**19**	**–**	**–**	**19**
Purchases of reserves in place	**364**	**–**	**–**	**364**
Sales of reserves in place	**–**	**–**	**–**	**–**
Production	**(426)**	**(4)**	**(5)**	**(435)**
Economic revisions due to prices	**105**	**6**	**–**	**111**
Revisions of prior estimates	**83**	**9**	**(4)**	**88**
Reserves, December 31, 2010	**3,421**	**78**	**76**	**3,575**
Net proved developed reserves				
December 31, 2007	2,731	58	53	2,842
December 31, 2008	2,690	45	89	2,824
December 31, 2009	2,333	45	81	2,459
December 31, 2010	**2,557**	**49**	**72**	**2,678**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2010				
(millions of Canadian dollars)	**North America[(1)]**	**North Sea**	**Offshore West Africa**	**Other**	**Total**
Proved properties	**$ 53,859**	**$ 3,757**	**$ 2,943**	**$ 14**	**$ 60,573**
Unproved properties	**3,284**	**–**	**–**	**31**	**3,315**
	57,143	**3,757**	**2,943**	**45**	**63,888**
Less: accumulated depletion and depreciation	**(25,547)**	**(3,371)**	**(2,071)**	**(14)**	**(31,003)**
Net capitalized costs	**$ 31,596**	**$ 386**	**$ 872**	**$ 31**	**$ 32,885**

(1) As at December 31, 2010, the Company's Oil Sands Mining and Upgrading segment has been included in North America capitalized costs in accordance with revisions to SEC oil and gas disclosures in Regulations S–K and S–X and FASB Topic 932 – "Extractive Activities – Oil and Gas".

	2009				
(millions of Canadian dollars)	North America[(1)]	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 49,052	$ 3,875	$ 2,195	$ 14	$ 55,136
Unproved properties	2,854	4	666	28	3,552
	51,906	3,879	2,861	42	58,688
Less: accumulated depletion and depreciation	(24,216)	(3,260)	(1,170)	(14)	(28,660)
Net capitalized costs	$ 27,690	$ 619	$ 1,691	$ 28	$ 30,028

(1) As at December 31, 2009, the Company's Oil Sands Mining and Upgrading segment has been included in North America capitalized costs in accordance with revisions to SEC oil and gas disclosures in Regulations S–K and S–X and FASB Topic 932 – "Extractive Activities – Oil and Gas".

	2008				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 34,386	$ 4,155	$ 2,076	$ 14	$ 40,631
Unproved properties	2,271	12	595	26	2,904
	36,657	4,167	2,671	40	43,535
Less: accumulated depletion and depreciation	(21,857)	(3,366)	(777)	(14)	(26,014)
Net capitalized costs	$ 14,800	$ 801	$ 1,894	$ 26	$ 17,521

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

(millions of Canadian dollars)	2010 North America(1)	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	**$ 1,904**	**$ –**	**$ –**	**$ –**	**$ 1,904**
Unproved	**141**	**–**	**–**	**–**	**141**
Exploration	**267**	**12**	**1**	**–**	**280**
Development	**2,926**	**96**	**235**	**3**	**3,260**
Costs incurred	**$ 5,238**	**$ 108**	**$ 236**	**$ 3**	**$ 5,585**

(1) As at December 31, 2010, the Company's Oil Sands Mining and Upgrading segment has been included in North America costs incurred in crude oil and natural gas activities in accordance with SEC oil and gas disclosures in Regulations S-K and S-X and FASB Topic 932 – "Extractive Activities – Oil and Gas".

(millions of Canadian dollars)	2009 North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 6	$ –	$ –	$ –	$ 6
Unproved	69	–	–	–	69
Exploration	173	36	1	–	210
Development	1,480	278	654	2	2,414
Costs incurred	$ 1,728	$ 314	$ 655	$ 2	$ 2,699

(1) Excludes additions related to the Company's Oil Sands Mining and Upgrading Segment.

(millions of Canadian dollars)	2008 North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 299	$ (7)	$ 44	$ –	$ 336
Unproved	84	1	1	–	86
Exploration	144	3	–	1	148
Development	1,810	195	772	–	2,777
Costs incurred	$ 2,337	$ 192	$ 817	$ 1	$ 3,347

RESULTS OF OPERATIONS FROM CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2010, 2009, and 2008 are summarized in the following tables:

	2010			
(millions of Canadian dollars)	**North America**[(1)]	**North Sea**	**Offshore West Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 9,673**	**$ 1,059**	**$ 821**	**$ 11,553**
Production	**(2,883)**	**(385)**	**(167)**	**(3,435)**
Transportation	**(365)**	**(8)**	**(1)**	**(374)**
Depletion, depreciation and amortization[(2)]	**(1,349)**	**(249)**	**(937)**	**(2,535)**
Asset retirement obligation accretion	**(68)**	**(33)**	**(6)**	**(107)**
Petroleum revenue tax	**–**	**(97)**	**–**	**(97)**
Income tax	**(1,407)**	**(144)**	**141**	**(1,410)**
Results of operations	**$ 3,601**	**$ 143**	**$ (149)**	**$ 3,595**

(1) For the year ended December 31, 2010, the Company's Oil Sands Mining and Upgrading segment has been included in North America results of operations from crude oil and natural gas producing activities in accordance with revisions to SEC oil and gas disclosures in Regulations S-K and S-X and FASB Topic 932 – "Extractive Activities – Oil and Gas".
(2) Includes the impact of a ceiling test impairment at December 31, 2010 of $684 million, pre-tax.

	2009			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 7,121	$ 1,334	$ 832	$ 9,287
Production	(1,748)	(376)	(179)	(2,303)
Transportation	(284)	(8)	(1)	(293)
Depletion, depreciation and amortization[(1)]	(2,186)	(207)	(527)	(2,920)
Asset retirement obligation accretion	(41)	(24)	(4)	(69)
Petroleum revenue tax	–	(85)	–	(85)
Income tax	(833)	(317)	(30)	(1,180)
Results of operations	$ 2,029	$ 317	$ 91	$ 2,437

(1) Includes the impact of ceiling test impairments at December 31, 2009 of $1,108 million, pre-tax.

	2008			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 8,126	$ 1,731	$ 801	$ 10,658
Production	(1,881)	(457)	(102)	(2,440)
Transportation	(327)	(10)	(1)	(338)
Depletion, depreciation and amortization[(1)]	(9,661)	(1,564)	(132)	(11,357)
Asset retirement obligation accretion	(42)	(27)	(2)	(71)
Petroleum revenue tax	–	(143)	–	(143)
Income tax	1,128	235	(141)	1,222
Results of operations	$ (2,657)	$ (235)	$ 423	$ (2,469)

(1) Includes the impact of ceiling test impairments at December 31, 2008 of $8,665 million, pre-tax.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED CRUDE OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the average first-day-of-the-month price during the previous 12-month period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than average first-day-of-the-month prices during the previous 12-month period and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 – "Extractive Activities – Oil and Gas":

		2010		
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	**$ 221,337**	**$ 21,117**	**$ 8,268**	**$ 250,722**
Future production costs	**(96,899)**	**(8,596)**	**(1,884)**	**(107,379)**
Future development and asset retirement obligations	**(35,424)**	**(5,448)**	**(688)**	**(41,560)**
Future income taxes	**(17,249)**	**(5,572)**	**(1,760)**	**(24,581)**
Future net cash flows	**71,765**	**1,501**	**3,936**	**77,202**
10% annual discount for timing of future cash flows	**(47,687)**	**(722)**	**(1,906)**	**(50,315)**
Standardized measure of future net cash flows	**$ 24,078**	**$ 779**	**$ 2,030**	**$ 26,887**

		2009		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 176,866	$ 16,304	$ 8,305	$ 201,475
Future production costs	(88,134)	(6,929)	(3,255)	(98,318)
Future development and asset retirement obligations	(22,767)	(5,271)	(975)	(29,013)
Future income taxes	(11,237)	(3,487)	(1,229)	(15,953)
Future net cash flows	54,728	617	2,846	58,191
10% annual discount for timing of future cash flows	(35,526)	(275)	(1,345)	(37,146)
Standardized measure of future net cash flows	$ 19,202	$ 342	$ 1,501	$ 21,045

(millions of Canadian dollars)	2008 North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 51,913	$ 13,681	$ 6,789	$ 72,383
Future production costs	(23,747)	(6,845)	(3,000)	(33,592)
Future development and asset retirement obligations	(9,238)	(4,674)	(364)	(14,276)
Future income taxes	(3,097)	(2,011)	(1,061)	(6,169)
Future net cash flows	15,831	151	2,364	18,346
10% annual discount for timing of future cash flows	(6,872)	(76)	(1,011)	(7,959)
Standardized measure of future net cash flows	$ 8,959	$ 75	$ 1,353	$ 10,387

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2010**	2009	2008
Sales of crude oil and natural gas produced, net of production costs	**$ (7,641)**	$ (5,437)	$ (9,679)
Net changes in sales prices and production costs	**14,748**	16,808	(14,680)
Extensions, discoveries and improved recovery	**1,636**	4,222	820
Changes in estimated future development costs	**(5,208)**	(2,752)	(715)
Purchases of proved reserves in place	**1,894**	53	113
Sales of proved reserves in place	**–**	(7)	(1)
Revisions of previous reserve estimates	**2,567**	220	112
Accretion of discount	**2,757**	1,375	3,468
SEC reliable technology	**–**	254	–
SEC rule transition	**–**	7,332	–
Changes in production timing and other	**(895)**	(2,788)	767
Net change in income taxes	**(4,016)**	(8,622)	8,462
Net change	**5,842**	10,658	(11,333)
Balance – beginning of year	**21,045**	10,387	21,720
Balance – end of year	**$ 26,887**	$ 21,045	$ 10,387

Ten-Year Review

Years ended December 31	**2010**	2009	2008	2007	2006	2005	2004	2003	2002	2001
FINANCIAL INFORMATION (1) (C$ millions, except per share amounts)										
Net earnings	**1,697**	1,580	4,985	2,608	2,524	1,050	1,405	1,403	539	639
Per share - basic	**$ 1.56**	$ 1.46	$ 4.61	$ 2.42	$ 2.35	$ 0.98	$ 1.31	$ 1.31	$ 0.53	$ 0.66
Cash flow from operations (2)	**6,321**	6,090	6,969	6,198	4,932	5,021	3,769	3,160	2,254	1,920
Per share - basic	**$ 5.81**	$ 5.62	$ 6.45	$ 5.75	$ 4.59	$ 4.68	$ 3.52	$ 2.94	$ 2.21	$ 1.98
Capital expenditures, net of dispositions (including business combinations)	**5,506**	2,997	7,451	6,425	12,025	4,932	4,633	2,506	4,069	1,885
Balance sheet information										
Working capital surplus (deficiency)	**(984)**	(514)	(28)	(1,382)	(832)	(1,774)	(652)	(505)	(14)	(6)
Property, plant and equipment, net	**40,472**	39,115	38,966	33,902	30,767	19,694	17,064	13,714	12,934	8,766
Total assets	**42,669**	41,024	42,650	36,114	33,160	21,852	18,372	14,643	13,793	9,290
Long-term debt	**8,499**	9,658	12,596	10,940	11,043	3,321	3,538	2,748	4,200	2,788
Shareholders' equity	**20,985**	19,426	18,374	13,321	10,690	8,237	7,324	6,006	4,754	3,928
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**1,090,848**	1,084,654	1,081,982	1,079,458	1,075,806	1,072,696	1,072,722	1,069,852	1,070,208	969,608
Weighted average shares outstanding (thousands)	**1,088,096**	1,083,850	1,081,294	1,078,672	1,074,678	1,073,300	1,072,446	1,073,880	1,023,064	970,400
Dividends declared per common share	**$ 0.30**	$ 0.21	$ 0.20	$ 0.17	$ 0.15	$ 0.12	$ 0.10	$ 0.08	$ 0.07	$ 0.05
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**661,832**	1,040,320	1,359,476	858,068	1,017,870	1,275,984	1,212,048	1,181,404	1,238,632	1,069,952
Share price ($/share)										
High	**$ 45.00**	$ 39.50	$ 55.65	$ 40.01	$ 36.96	$ 31.00	$ 13.79	$ 8.41	$ 6.82	$ 6.55
Low	**$ 31.97**	$ 17.93	$ 17.10	$ 26.23	$ 22.75	$ 12.14	$ 7.98	$ 5.65	$ 4.70	$ 4.49
Close	**$ 44.35**	$ 38.00	$ 24.38	$ 36.29	$ 31.08	$ 28.82	$ 12.82	$ 8.17	$ 5.85	$ 4.79
NYSE – US$										
Trading volume (thousands)	**759,327**	1,514,614	1,934,456	972,532	803,818	503,108	250,936	93,832	63,728	41,528
Share price ($/share)										
High	**$ 44.77**	$ 38.26	$ 54.66	$ 43.59	$ 32.19	$ 27.03	$ 11.19	$ 6.43	$ 4.36	$ 4.32
Low	**$ 30.00**	$ 13.85	$ 13.22	$ 22.28	$ 20.15	$ 9.87	$ 5.97	$ 3.66	$ 2.95	$ 2.85
Close	**$ 44.42**	$ 35.98	$ 19.99	$ 36.57	$ 26.62	$ 24.81	$ 10.70	$ 6.31	$ 3.71	$ 3.05
RATIOS										
Debt to book capitalization (3)	**29%**	33%	41%	45%	51%	29%	34%	33%	47%	42%
Return on average common shareholders' equity, after tax (3)	**8%**	8%	33%	22%	27%	14%	21%	26%	13%	18%
Daily production before royalties per ten thousand common shares (BOE/d) (1)	**5.8**	5.3	5.2	5.7	5.4	5.2	4.8	4.3	4.1	3.7
Total proved plus probable reserves per common share (BOE) (1)(4)	**6.3**	5.8	3.1	3.2	3.2	2.4	2.2	2.0	1.7	1.6
Net asset value per common share (1)(5)	**$ 64.76**	$ 64.92	$ 39.89	$ 34.47	$ 28.21	$ 30.22	$ 16.57	$ 11.68	$ 9.79	$ 8.44

(1) Restated to reflect two-for-one share splits in May 2010, May 2005 and May 2004.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. Cash flow from operations may not be comparable to similar measures used by other companies.

(3) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.

(4) Based upon company gross reserves (forecast prices and costs, before royalties), using year-end common shares outstanding. Excludes Horizon SCO reserves prior to 2009. Prior to 2010, company gross reserves were prepared using constant prices and costs.

(5) Calculated as the net present value of future net revenue of the Company's total proved plus probable reserves prepared using forecast prices and costs discounted at 10%, as reported in the Company's AIF, with $300/acre added for core unproved property ($250/acre for core undeveloped land from 2005 to 2009, $75/acre for core undeveloped land for all years prior to 2005), less net debt and using year end common shares outstanding. Net debt is the Company's long-term debt plus/minus the working capital deficit/surplus. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs have been applied against the future net revenue.

Years ended December 31	**2010**	2009	2008	2007	2006	2005	2004	2003	2002	2001
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) (6)										
Company net proved reserves (after royalties)										
North America	**2,763**	2,664	948	920	887	694	648	588	571	583
North Sea	**252**	240	256	310	299	290	303	222	202	78
Offshore West Africa	**101**	123	142	128	130	134	115	85	75	60
	3,116	3,027	1,346	1,358	1,316	1,118	1,066	895	848	721
Horizon SCO	–	–	1,946	1,761	1,596	1,626	–	–	–	–
Company net proved plus probable reserves (after royalties)										
North America	**4,293**	4,172	1,599	1,545	1,502	1,035	926	857	636	670
North Sea	**376**	387	399	405	422	417	415	317	277	100
Offshore West Africa	**149**	179	191	186	195	206	196	133	121	103
	4,818	4,738	2,189	2,136	2,119	1,658	1,537	1,307	1,034	873
Horizon SCO	–	–	2,944	2,680	2,542	2,566	–	–	–	–
Natural gas (Bcf) (6)										
Company net proved reserves (after royalties)										
North America	**3,638**	3,027	3,523	3,521	3,705	2,741	2,591	2,426	2,446	2,064
North Sea	**78**	67	67	81	37	29	27	62	71	94
Offshore West Africa	**76**	85	94	64	56	72	72	64	71	67
	3,792	3,179	3,684	3,666	3,798	2,842	2,690	2,552	2,588	2,225
Company net proved plus probable reserves (after royalties)										
North America	**4,870**	3,992	4,619	4,602	4,857	3,548	3,319	2,919	2,765	2,344
North Sea	**107**	94	94	113	93	69	57	102	89	118
Offshore West Africa	**113**	124	131	88	99	110	90	72	90	88
	5,090	4,210	4,844	4,803	5,049	3,727	3,466	3,093	2,944	2,550
Total proved reserves (after royalties) (MMBOE)	**3,748**	3,557	1,960	1,969	1,949	1,592	1,514	1,320	1,279	1,092
Total proved plus probable reserves (after royalties) (MMBOE)	**5,666**	5,440	2,996	2,937	2,961	2,279	2,115	1,823	1,525	1,298
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America - Exploration and Production	**271**	234	244	247	235	222	206	175	169	167
North America - Oil Sands Mining and Upgrading	**91**	50	–	–	–	–	–	–	–	–
North Sea	**33**	38	45	56	60	68	65	57	39	36
Offshore West Africa	**30**	33	27	28	37	23	12	10	7	3
	425	355	316	331	332	313	283	242	215	206
Natural gas (MMcf/d)										
North America	**1,217**	1,287	1,472	1,643	1,468	1,416	1,330	1,245	1,204	906
North Sea	**10**	10	10	13	15	19	50	46	27	12
Offshore West Africa	**16**	18	13	12	9	4	8	8	1	–
	1,243	1,315	1,495	1,668	1,492	1,439	1,388	1,299	1,232	918
Total production (before royalties) (MBOE/d)	**632**	575	565	609	581	553	514	459	421	359
Product pricing										
Average crude oil and NGLs price ($/bbl)	**65.81**	57.68	82.41	55.45	53.65	46.86	37.99	32.66	31.22	23.45
Average natural gas price ($/Mcf)	**4.08**	4.53	8.39	6.85	6.72	8.57	6.50	6.21	3.77	5.45
Average SCO price ($/bbl)	**77.89**	70.83	–	–	–	–	–	–	–	–

(6) 2010 company net reserves were prepared using forecast prices and costs; prior to 2010, company net reserves were prepared using constant price and costs. Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with the SEC's Industry Guide 7. With the SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserves totals.

Corporate Information

BOARD OF DIRECTORS

***Catherine M. Best,** FCA, ICD.D (1)(2)
Corporate Director
Calgary, Alberta

N. Murray Edwards (5)
President, Edco Financial Holdings Ltd.
Calgary, Alberta

***Timothy W. Faithfull** (1)(3)
Corporate Director
Calgary, Alberta

***Honourable Gary A. Filmon,** P.C., OC., O.M. (1)(4)
Consultant, The Exchange Consulting Group
Winnipeg, Manitoba

***Christopher L. Fong** (3)(5)
Corporate Director
Calgary, Alberta

***Ambassador Gordon D. Giffin** (1)(4)
Senior Partner, McKenna Long & Aldridge LLP
Atlanta, Georgia

***Wilfred A. Gobert** (2)(4)
Corporate Director
Calgary, Alberta

Steve W. Laut
President, Canadian Natural Resources Limited
Calgary, Alberta

Keith A. J. MacPhail (3)(5)
Chairman & Chief Executive Officer, Bonavista Energy Corporation
Calgary, Alberta

Allan P. Markin, OC., A.O.E. (3)
Chairman of the Board, Canadian Natural Resources Limited
Calgary, Alberta

***Honourable Frank J. McKenna,** P.C., OC., O.N.B., Q.C. (2)(4)
Deputy Chair, TD Bank Financial Group
Cap Pelé, New Brunswick

***James S. Palmer,** C.M., A.O.E., Q.C. (2)(5)
Chairman & Partner, Burnet, Duckworth & Palmer LLP
Calgary, Alberta

***Dr. Eldon R. Smith,** OC., M.D. (2)(3)
President of Eldon R. Smith & Associates Ltd.
Professor Emeritus and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

***David A. Tuer** (1)(5)
Vice-Chairman & Chief Executive Officer, Teine Energy Ltd.
Calgary, Alberta

MANAGEMENT COMMITTEE

Allan P. Markin
Chairman of the Board

N. Murray Edwards
Vice-Chairman

John G. Langille
Vice-Chairman

Steve W. Laut
President

Tim S. McKay
Chief Operating Officer

Douglas A. Proll
Chief Financial Officer & Senior Vice-President, Finance

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Horizon Projects

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, Thermal & International

Allen M. Knight
Senior Vice-President, International & Corporate Development

Cameron S. Kramer
Senior Vice-President, North American Operations

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Corey B. Bieber
Vice-President, Finance & Investor Relations

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

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(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety and Environmental Committee member
(4) Nominating and Corporate Governance Committee member
(5) Reserves Committee member

* Determined to be independent by the Nominating and Corporate Governance Committee and the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

General Information

CORPORATE GOVERNANCE

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a share bonus plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the share bonus plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2010 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting.

CORPORATE OFFICES

HEAD OFFICE

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REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Sproule International Limited
Calgary, Alberta

COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

Abbreviations can be found on page 24.

METRIC CONVERSION CHART

To convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid on the first day of every January, April, July and October. The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31 and is restated for the two-for-one subdivision of the common shares which occurred in May 2010.

	2010	2009	2008
Cash dividends declared per common share	$ 0.30	$ 0.21	$ 0.20

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of the Shareholders will be held on Thursday, May 5, 2011 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

STOCK LISTING - CNQ

Toronto Stock Exchange
The New York Stock Exchange

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