The Premium Value,
Defined Growth, Independent.

Canadian Natural

2005 Annual Report

General information

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

AECO	Alberta natural gas reference location
AIF	Annual Information Form
bbl	barrel
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
C$	Canadian dollars
CBM	Coal Bed Methane
CNUG	Canadian Natural Upgrader
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse Gas
Horizon Project	Horizon Oil Sands Project
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/d	million cubic feet per day
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OOIP	Original Oil In Place
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic light crude oil
SEC	Securities and Exchange Commission
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCS	Western Canadian Select crude oil blend
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

CAUTIONARY STATEMENTS

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. Please refer to page 45 for the complete special note regarding forward-looking statements.

All production and sales statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Methodologies for determining annual reserves are described on pages 40 to 44.

This report also includes references to financial measures commonly used in the oil and gas industry that are not defined by Generally Accepted Accounting Principles ("GAAP"). The Company uses these measures to evaluate its performance, however they should not be considered an alternative to or more meaningful than net earnings.

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1st, 2001. Since then, dividends have been paid on the first day of every January, April, July and October.

The following table, restated for the two-for-one subdivisions of the common shares that occurred in May 2004 and May 2005, shows the aggregate amount of the cash dividends declared per common share in each of its last three years ended December 31.

	2005	2004	2003
Cash dividends declared per common share	$ 0.24	$ 0.20	$ 0.15

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of Shareholders will be held on Thursday, May 4, 2006 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

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

The People

Our people are motivated and competent. Our technical skills are compounding, allowing us to maintain our core competencies and pursue larger and more complex projects.

The Plan

Our exploitation based strategy allocates capital in a balanced manner, providing near-, mid- and long-term growth initiatives. This plan provides significant transparency to investors.

The Assets

Our strong asset base is comprised of a deep portfolio of conventional oil and gas opportunities in North America, the North Sea and Offshore West Africa. This is bolstered by a vast oil sands resource base in Alberta capable of supporting over 675,000 barrels per day of light sweet SCO production for years to come.

Capitalizing on opportunities.

Relying on our People and applying their expanding technical skills to our vast Asset portfolio has allowed us to extend our Plan for oil sands development. This includes targeting further expansions at the Horizon Project as well as the development of our in-situ lands together with the construction of the Canadian Natural Upgrader which will be capable of upgrading this product to light, sweet Synthetic Crude Oil.

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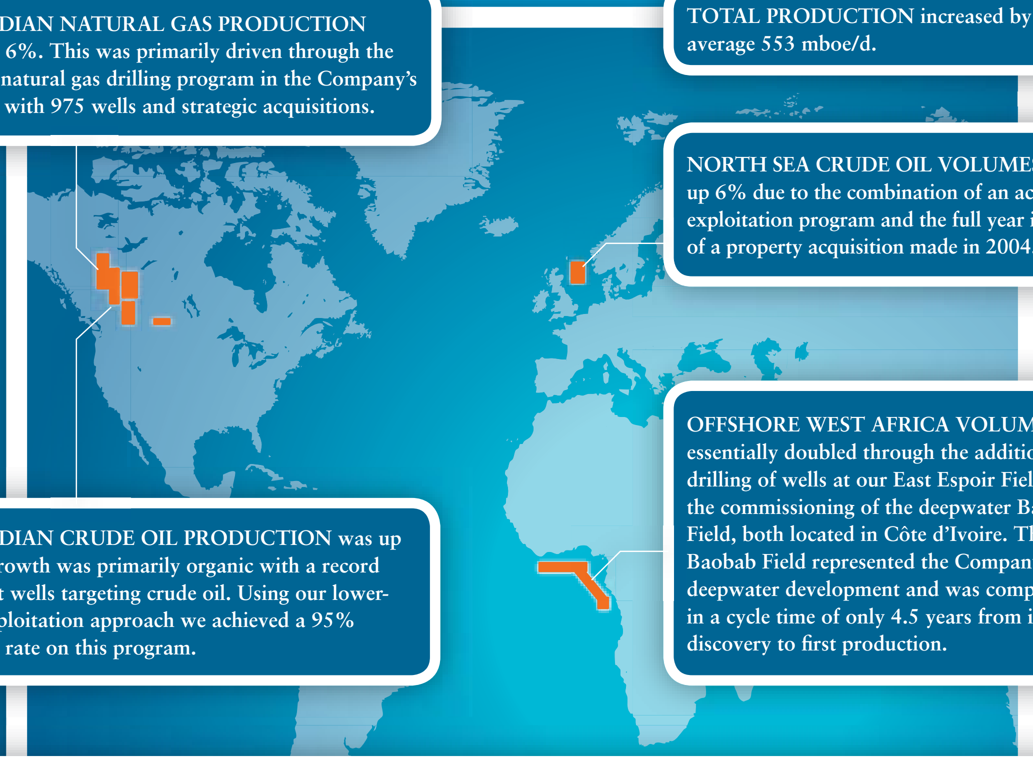
Conventional Operations Year in Review

COST CONTROL remains strong, reflecting the benefits of leveraging a large infrastructure to create economies of scale. This ability also lends itself to capital efficiencies.

NET CONVENTIONAL PROVED RESERVES additions were 145% of net production at a finding and onstream cost of $13.41/boe (3-year average $12.55/boe). Using net proved and probable reserves we replaced 195% of net production at a finding and onstream cost of $9.97/boe (3-year average $8.05/boe). In addition, we booked 2.2 billion barrels of gross proved (3.4 billion barrels of gross proved and probable) mineable bitumen reserves at our Horizon Project.

CANADIAN NATURAL GAS PRODUCTION was up 6%. This was primarily driven through the largest natural gas drilling program in the Company's history with 975 wells and strategic acquisitions.

TOTAL PRODUCTION increased by 8% to average 553 mboe/d.



NORTH SEA CRUDE OIL VOLUMES were up 6% due to the combination of an active exploitation program and the full year impact of a property acquisition made in 2004.

OFFSHORE WEST AFRICA VOLUMES essentially doubled through the additional drilling of wells at our East Espoir Field and the commissioning of the deepwater Baobab Field, both located in Côte d'Ivoire. The Baobab Field represented the Company's first deepwater development and was completed in a cycle time of only 4.5 years from initial discovery to first production.

CANADIAN CRUDE OIL PRODUCTION was up 7%. Growth was primarily organic with a record 642 net wells targeting crude oil. Using our lower-risk exploitation approach we achieved a 95% success rate on this program.

OUR PROJECT INVENTORY WAS STRENGTHENED DURING 2005 AS FOLLOWS:

- Total landholdings, the input to sustainable conventional growth, increased during the year. As the second largest landholder in the WCSB, it provides us with leverage in most play types found in the basin.
- Secondary and enhanced recovery schemes are working at Pelican Lake in Alberta, increasing the potential of this large prolific field.
- Additional phases of development were announced for the Horizon Project targeting up to 500 mbbl/d of production from our oil sands mining leases.
- The success of our heavy crude oil marketing plan provided the confidence to announce the planned, stepwise, development of 300 mbbl/d of new in-situ production over the next several years.
- We are reviewing a second bitumen upgrader, in addition to the one integrated with the Horizon Project was announced in tandem with our in-situ developments. Implementation of cost control schemes such as gasification technologies in our oil sands developments is planned.
- We captured a new exploitation development of a proved light crude oil field located offshore Gabon.

Our disciplined approach continues to deliver strong production volumes at a low cost.

The Horizon Oil Sands Project

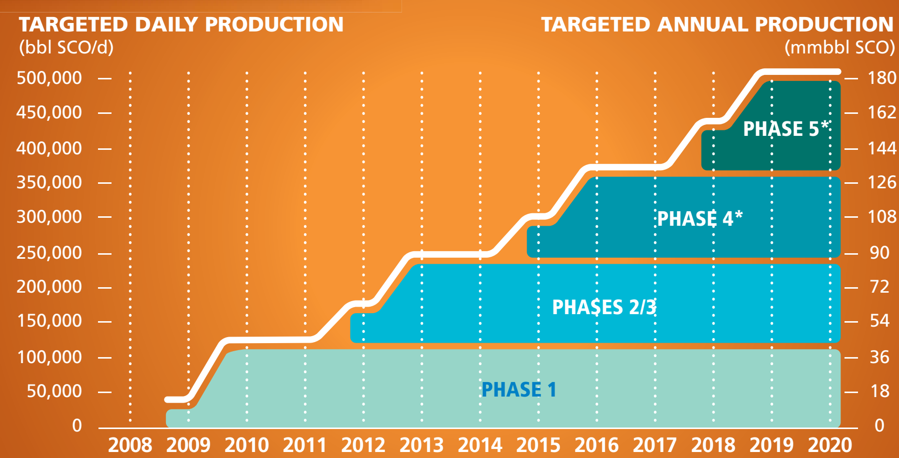
THE HORIZON OIL SANDS PROJECT ("Horizon Project") represents a world class crude oil development with the following characteristics:

- Low geological risk as it is delineated by several hundred stratigraphic wells. We know the resource base and its characteristics.
- Bitumen is upgraded on-site to a light sweet synthetic crude oil that is sold at a premium to WTI during 2005.
- No production declines normally associated with conventional crude oil and natural gas operations. Production is sustainable; literally, for decades to come.
- Only reliable, proven technologies have been utilized.

Due to minimal capital reinvestment requirements, this translates into consistent high free cash flow generation capability for decades to come.

OUR DISCIPLINED APPROACH to this development is being leveraged to its utmost. Prior to sanctioning, we spent 4 years and over $400 million to understand what we wanted to build and how we wanted to build it. This investment was well worth the effort. It helped us to achieve cost certainty in the form of targeting 68% of construction costs under fixed price bids, a first in the oil sands industry.

DURING 2005 we made significant headway on construction activities, accomplishing about 19% of Phase 1 construction by year end. It is still early, but we remain on-time and on-schedule. Many of the foundations were completed and all winter-critical path items remained on track. We target to be approximately 55% completed by the end of 2006.



* includes in-situ production for Birch Mountain

OUR CREATIVE LABOUR strategy was a further outcome from this preplanning. The addition of an on-site 737–capable airstrip has enabled workers from all across Canada to participate in our managed open site. This expanded access to labour is a critical success factor as the construction effort continues. Our first class camp facilities augment this plan.

WE ARE REVIEWING the option of combining Phases 2 and 3 into one phase bringing total production to approximately 232 mbbl/d by approximately 2011. Doing so may enable us to keep more trained workers remaining on site in a competitive market. Financially we are capable of accomplishing it. We will fully investigate the merits of this and will decide by early 2007.

WE ANNOUNCED ADDITIONAL FUTURE PHASES 4 AND 5 late in 2005 which will seek to optimize the development of this vast asset base. These phases, augmented by bitumen feedstock from in-situ operations, will result in total production capacity of about 500 mbbl/d of light sweet synthetic crude oil from the leases by 2017.

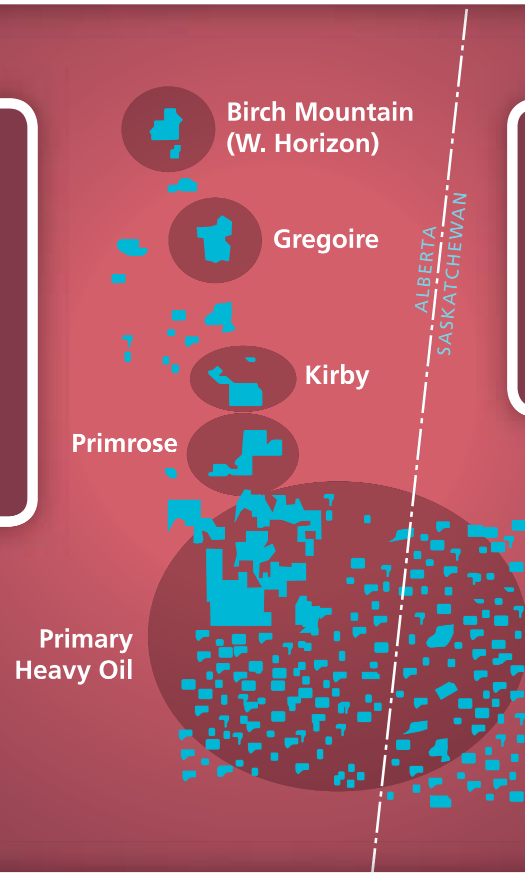
Horizon will add significant shareholder value for decades to come.

Canadian Natural Upgrader and In-situ Developments

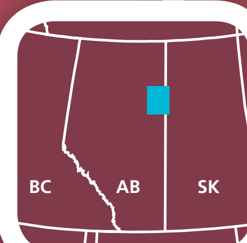
CANADIAN NATURAL OWNS A TREMENDOUS ASSET BASE in the heavy crude oil and oil sands regions of Canada. The challenge has been to develop these assets in a methodical and disciplined manner due to the limitations imposed by refiner conversion capacity.

OUR HEAVY CRUDE OIL MARKETING STRATEGY seeks to overcome this challenge. We have been aggressive in the execution of this strategy over the last two years. We are now the largest blender of heavy crude oil in Canada at about 140 mbbl/d during 2005, creating products that are usable by more refiners within our traditional geographic market. We support various pipeline initiatives to expand the geographic reach of our marketing efforts, and in 2005 we committed 25 mbbl/d to the Coriscana Pipeline delivering our heavy crude oil directly into the US Gulf Coast where significant conversion capacity exists. The final leg of the strategy is to encourage the creation of more conversion capacity in our markets.

THE PROPOSED CANADIAN NATURAL UPGRADER represents the logical extension of this third effort and leverages the upgrading and project management technical expertise from our Horizon Project. We will complete a Scoping Study to determine the optimal technology, location, size and product output of this heavy oil upgrader in 2006. If approved, we will utilize the same disciplined approach that is making the Horizon Project so successful – front end engineering and design.



THE ECONOMICS OF THE UPGRADER ARE ROBUST; in a US$35/bbl WTI price world we would expect to increase per barrel net backs by approximately US$9.50 over selling bitumen alone. Additionally, since we will be selling a light crude oil capable of feeding most refineries we reduce the impacts of existing heavy crude oil conversion capacity limits.



OUR PRIMROSE, KIRBY, GREGOIRE AND BIRCH MOUNTAIN in-situ opportunities headline a vast oil sands opportunity for our shareholders. We will develop these and other properties to provide feedstock for our upgraders. We target to bring on about 300 mbbl/d of new in-situ production in manageable, stepwise increments of 30 mbbl/d over the next several years.

Lightening the mix reduces marketing risks and increases netbacks.

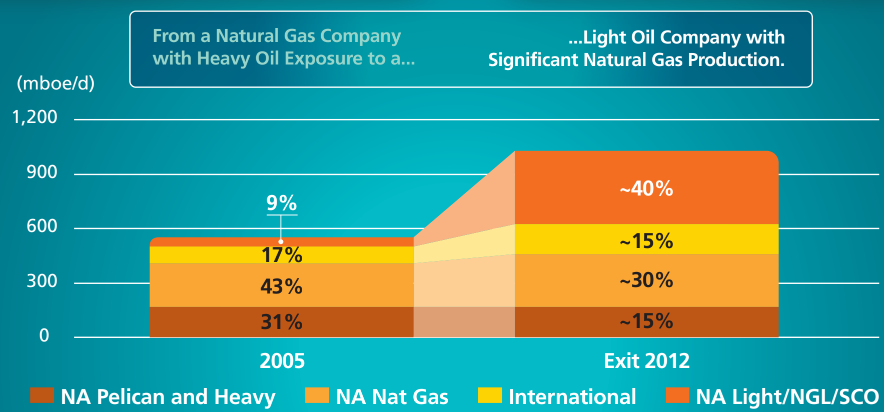
The Defined Plan for Profitable Future Growth

OUR PROJECT INVENTORY HAS NEVER BEEN STRONGER and this affords us the ability to add significant transparency to our defined growth plan. We articulate the optimal 5-year organic development strategy for every product and every basin in which we operate. Our knowledge of our basins, historic track records and lower-risk exploitation focus facilitate a realistic determination of base production declines, and results of the planned drill program. Major new project development expenditures and a conservative price deck of flat US$35/bbl WTI are then applied to obtain a financial view of the Company.

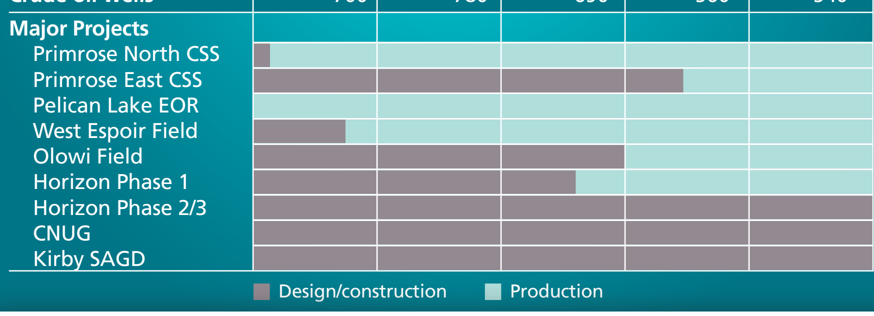
EVEN WITH CONSERVATIVE PRICING we remain well within our targeted financial ratios. Opportunistic acquisitions have always been a key element of our strategy, and we have diligently altered our organic plans to accommodate them. That is the strength of owning and operating your project portfolio – you have the flexibility to alter plans on short notice. While current pricing of assets remain outside of our parameters, we maintain financial flexibility in our plan to accommodate such acquisitions should they become available.

OUR SKILL SET CONTINUES TO EVOLVE enabling us to take on larger and more complex projects. We have developed deep water development proficiency, upgrading expertise and mega project management skills. Our team has evolved to maximize the value of our asset base.

OUR FINANCIAL STRENGTH will allow us to continue to add to this expertise and to our project portfolio.



	2006	2007	2008	2009	2010
Natural gas wells	1,140	1,140	1,180	1,180	1,078
Crude oil wells	700	780	690	560	540



BY 2013, WE EXPECT OUR PRODUCTION LEVELS TO SIGNIFICANTLY INCREASE. Further given the nature of the additions we are making, our production mix will provide higher realizations and stronger cash flows. This will make Canadian Natural a larger more sustainable company throughout the resource price cycle.

Building an even stronger, more sustainable Canadian Natural.

Maintaining discipline.

We do not compromise on our values and do not chase commodity prices. Recent high commodity prices have shifted our short-term emphasis solely into organic growth as acquisitions are expensive. Every well we drill must still pass hurdle rates similar to prior years. Our major developments are still subject to extensive front end design prior to construction. Maintaining discipline is a core competency.

Financial Highlights

	2005	2004	2003
FINANCIAL ($ millions, except per share data)			
Revenue, before royalties	$ 10,107	$ 7,547	$ 6,155
Net earnings	$ 1,050	$ 1,405	$ 1,403
Per common share – basic [1]	$ 1.96	$ 2.62	$ 2.62
– diluted [1]	$ 1.95	$ 2.60	$ 2.53
Adjusted net earnings from operations [2]	$ 2,034	$ 1,405	$ 987
Per common share – basic [1]	$ 3.79	$ 2.62	$ 1.84
– diluted [1]	$ 3.78	$ 2.60	$ 1.80
Cash flow from operations [2]	$ 5,021	$ 3,769	$ 3,160
Per common share – basic [1]	$ 9.36	$ 7.03	$ 5.88
– diluted [1]	$ 9.33	$ 6.98	$ 5.76
Capital expenditures, net of dispositions	$ 4,932	$ 4,633	$ 2,506
Long-term debt	$ 3,321	$ 3,538	$ 2,748
Shareholders' equity	$ 8,237	$ 7,324	$ 6,006
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (mbbl/d)			
North America	222	206	175
North Sea	68	65	57
Offshore West Africa	23	12	10
	313	283	242
Natural gas (mmcf/d)			
North America	1,416	1,330	1,245
North Sea	19	50	46
Offshore West Africa	4	8	8
	1,439	1,388	1,299
Barrel of oil equivalent (mboe/d)	553	514	459
Average prices before royalties [3]			
Crude oil and NGLs ($/bbl)			
North America	$ 39.62	$ 33.16	$ 29.40
North Sea	$ 66.57	$ 51.37	$ 42.00
Offshore West Africa	$ 59.91	$ 49.05	$ 36.47
Company average	$ 46.86	$ 37.99	$ 32.66
Natural gas ($/mcf)			
North America	$ 8.65	$ 6.61	$ 6.34
North Sea	$ 3.17	$ 3.73	$ 3.03
Offshore West Africa	$ 5.91	$ 5.25	$ 4.37
Company average	$ 8.57	$ 6.50	$ 6.21

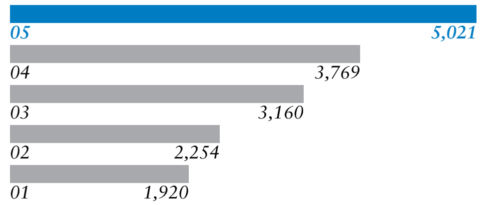
(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.

(2) Adjusted net earnings from operations and cash flow from operations are non-GAAP terms that represent net earnings adjusted for certain items of a non-operational and non-cash nature. The Company evaluates its performance based on these measures. Adjusted net earnings from operations and cash flow from operations may not be comparable to similar measures presented by other companies.

(3) Including transportation costs and excluding risk management activities.

2005 represented a record year in terms of production, reserves and cash flow. We remain poised for continued delivery.

Cash flow from operations
(C$ millions)



	2005	2004	2003
Drilling activity (net wells, excluding stratigraphic test/service wells)			
North America	1,617	1,099	1,338
North Sea	13	11	13
Offshore West Africa	4	3	2
	1,634	1,113	1,353
Core undeveloped landholdings (thousands of net acres)			
North America	10,947	11,523	9,811
North Sea	352	565	573
Offshore West Africa	426	886	943
Company gross proved reserves (before royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	785	695	672
North Sea	290	303	222
Offshore West Africa	148	125	106
	1,223	1,123	1,000
Conventional natural gas (bcf)			
North America	3,378	3,202	3,006
North Sea	29	27	62
Offshore West Africa	83	81	86
	3,490	3,310	3,154
Barrels of oil equivalent (mmboe)	1,804	1,674	1,526
Net proved reserves (after royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	694	648	588
North Sea	290	303	222
Offshore West Africa	134	115	85
	1,118	1,066	895
Conventional natural gas (bcf)			
North America	2,741	2,591	2,426
North Sea	29	27	62
Offshore West Africa	72	72	64
	2,842	2,690	2,552
Barrels of oil equivalent (mmboe)	1,592	1,514	1,320
Net oil sands proved mineable reserves (after royalties)			
Bitumen (mmbbl)	1,848	–	–
Synthetic Crude Oil* (mmbbl)	1,626	–	–

* SCO reserves are based upon upgrading of the bitumen reserves.
The reserves shown for bitumen and SCO are not additive.

THE PEOPLE

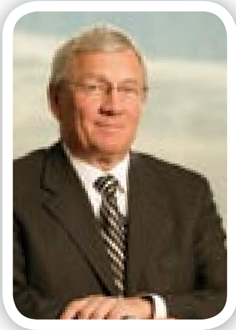
Our multi disciplinary teams leverage the skills of all members to deliver the Plan.

THE PLAN

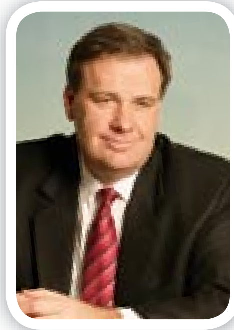
We develop strategies for every facet of our operations to optimize our resources and control costs.

THE ASSETS

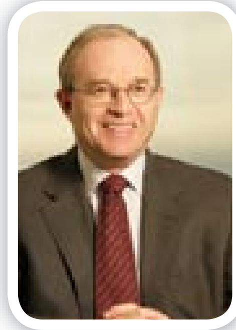
Our asset portfolio is deep, facilitating nimble reactions to changing business environments and opportunistic acquisitions.



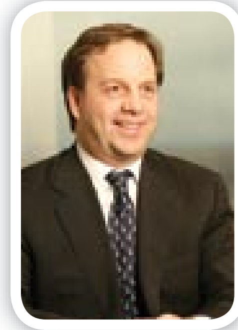
ALLAN P. MARKIN
Chairman



N. MURRAY EDWARDS
Vice-Chairman



JOHN G. LANGILLE
Vice-Chairman



STEVE W. LAUT
President & Chief Operating Officer

Letter to Shareholders

For Canadian Natural, 2005 was another exceptionally successful year. On the conventional side of the business, each of our four per-share business metrics have increased as shown below, adding to the substantial gains during the last 5 years.

	1–Year	5–Year
Growth per share in:		
Net production	8%	57%
Net proved and probable reserves	8%	66%
Cash flow	33%	132%
NAV of conventional reserves and land [1]	82%	194%

Over and above the conventional side of the business, we sanctioned Phase 1 of the Horizon Oil Sands Project ("Horizon Project") in early 2005, obtained lump sum bids on a substantial portion of Phase 1 construction costs and completed 19% of the construction effort. The Horizon Project will add significant value for shareholders, with commissioning of Phase 1 targeted at 110,000 barrels per day capacity of light sweet synthetic crude oil in the second half of 2008 (and ultimately targeted at 232,000 barrels per day as Phase 2 and 3 are commissioned) with no declines expected for decades to come. A year-end independent evaluation resulted in the booking of 3.4 billion barrels of gross proved and probable bitumen reserves for the Horizon Project.

We also added significant transparency to the longer term growth prospects of the Company by articulating our extensive in-situ oil sands plans and proposed heavy crude oil upgrader project as well as Phases 4 and 5 for the Horizon Project.

These proposed enhancements:

- Provide a natural migration of professional engineering and project management skills as well as construction workers;
- Unlock our vast heavy crude oil resource value potential;
- Capture a major portion of the value chain in the heavy crude oil business; and,
- Control operating costs through targeted application of gasification technologies.

(1) Discounted value of conventional reserves and undeveloped land less net debt.

STRATEGIES AND THE BUSINESS ENVIRONMENT

During 2005, commodity prices remained strong, enabling us to reduce long-term debt by approximately $400 million while both spending $1.3 billion on construction of the Horizon Project and delivering on our base conventional business. This left our debt to book capitalization at only 29%, or 5 percentage points better than where we entered the year.

However, this robust price environment has also resulted in a high demand for services and many cost control challenges. During 2005, the industry set records for active drill rigs, meters drilled and the numbers of wells drilled in western Canada. This combined with the general business and construction boom in western Canada places a high demand on the labour force and creates significant cost inflation for services. Many oilfield services and drilling day rate costs have increased by up to 30% over the past year. High activity levels have also resulted in a near doubling in per-hectare land acquisition costs.

As such, maintaining discipline remains a priority. By adhering to our strategies, we have been able to mitigate much of these cost increases, maintaining our cost competitiveness. For example, our production expense and our finding and onstream costs increased at below industry average rates, despite record drilling by the Company and an increase in total land ownership. This reflects the execution of a well thought out multi-year development and drilling plan and our domination of core region infrastructure, which facilitates low-cost reserve additions and synergistic cost savings across fields.

Canadian Natural's strategy allows us to allocate capital to maximize returns and remains predicated on:

- Maintaining a large project portfolio in every basin we operate to enable us to continually high-grade current developments;
- Maintaining balance in our product mix, project time horizons and financing strategies;

During 2005, our growth was primarily achieved though the drillbit as property acquisition costs remained high. This program resulted in crude oil production increases of 11% and natural gas volumes increases of 6% in Canada.

- Continually balancing between acquisitions and exploration, while remaining focused on low-cost exploitation;
- Identifying and completing acquisitions if they are cost effective and provide strategic upside; and,
- Controlling costs through area knowledge and domination of core focus regions.

2005 CONVENTIONAL OPERATIONS IN REVIEW

During 2005, our growth was primarily achieved through the drillbit as property acquisition costs remained high. Our drilling program resulted in crude oil production increases of about 11% over 2004 levels and natural gas volume increases of 6% in Canada. Expenditures on conventional operations represented about 68% of the cash flow generated by them.

INTERNATIONAL

Our International operations represented a significant portion of that growth. Average light crude oil production in the North Sea increased by about 4 thousand barrels per day or 6% from the previous year, the result of both an active in-fill drilling program and the full year impact of an acquisition made in mid-2004. We have sufficient exploitation projects in inventory to maintain and marginally grow volumes for the next several years on a very economic basis.

Our Offshore West African crude oil production volumes from Côte d'Ivoire effectively doubled from 11.6 thousand barrels per day in 2004 to average 22.9 thousand barrels per day in 2005. This reflected an active in-fill drilling program to access previously untapped portions of the East Espoir development as well as the commencement of production from our first deepwater development at Baobab. First production from Baobab was completed in just 4.5 years from first discovery – an excellent cycle time for deepwater developments. This achievement in our first deepwater development speaks to the technical expertise that we have developed and the diligence we demand in delivery.

We expect continued growth in Offshore West Africa as our West Espoir satellite development is completed in the second half of 2006 and as we forecast to commence production in late 2008 from our recently acquired Olowi Field located Offshore Gabon. The Olowi Field was acquired during the fourth quarter of 2005 and we filed our development plan with the Government of Gabon by the end of the year. In early 2006 we received required approvals and have already commenced the engineering tender process. The new opportunity created with the Olowi acquisition allows us to utilize our Offshore West Africa experience to quickly bring Olowi onstream.

NORTH AMERICAN NATURAL GAS

We remain a significant producer of natural gas in Canada, representing approximately 8.5% of western Canadian output. Further, our land base represents the second largest portfolio in the industry, meaning that we have exposure to virtually every play type found in the basin. As our largest single product offering at about 43% of our production mix in 2005, production increased by about 6% over 2004 levels driven largely by record natural gas drilling activity and the full year inclusion of property acquisitions made in 2004.

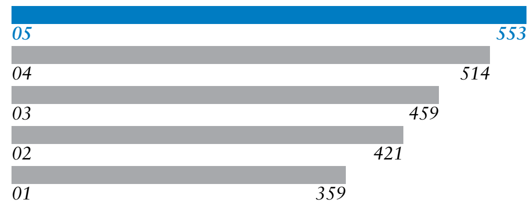
Most of the 2005 production growth was centered in Northwest Alberta where we continue to build on our strong base of assets acquired in 2002. This core region, along with our Northeast British Columbia core region, has the ability to drive corporate natural gas production growth of 3% to 5% for at least the next 5 years. Our Northern Plains core region will provide relatively flat to slightly declining production while the Southern Plains region has potential to grow volumes both through its shallow and coal bed methane natural gas programs.

Our 5-year defined plan incorporates a disciplined low-cost exploitation methodology for each of our natural gas assets assuming prices well below today's market pricing.

NORTH AMERICAN CRUDE OIL AND NGLS

Success in our Canadian crude oil operations continued with production increasing by over 7% from 2004 levels. At our Pelican Lake Field we reversed years of production declines through a successful waterflood rollout in portions of the field. The development of Pelican Lake has occurred in a very disciplined manner. We experimented with different approaches

Total production, before royalties
(mboe/d)



to the waterflood, initially obtaining a tripling of production with water cuts of 70%-80%. Our current approach, however, is providing per well crude oil production increases of 10-15 times with water cuts of only 10%. This application of waterflood may ultimately double expected recovery factors from the reservoir. This same diligence will be used in our current testing of polymer floods, which have the potential to again significantly increase recovery factors from the Field. Based on our success, we now expect to ramp production levels at this Field and significantly extend Field life.

Our conventional heavy crude oil production grew throughout the year following the most active drilling program in our history. Similar to our natural gas approach we also have an extensive 5 year development plan for these assets allowing us to maintain and grow volumes in a very disciplined manner. We continually leverage our large infrastructure and land base to control costs.

Our thermal in-situ oil sands developments also continue to outperform our expectations. The Primrose development continued with the addition of 109 net new wells, which yielded production increases of approximately 22% over 2004 levels. Overall, the new Primrose well pads continue to produce at rates approximately 17% better than expected. The Primrose North expansion also continued on time and on budget with first crude oil production coming on stream in early 2006. This expansion will add about 30,000 barrels per day to exit rate production capacity in 2006.

Our heavy crude oil assets in Alberta represent a substantial opportunity. We have extensive landholdings with both primary and in-situ oil sands areas that continue to deliver significant returns. However, in order to capitalize on these assets in a disciplined manner the Company has developed a strong marketing plan. We first articulated our heavy crude oil marketing strategy in 2003 and we have since been successfully executing against that plan.

At about 140,000 barrels per day, Canadian Natural is now the largest blender of crude oils in western Canada. This blending strategy represents the first element of the marketing strategy and allows us to sell product to an expanded group of refiners within our traditional geographic markets. The blending strategy has evolved to allow for multiple blends that can be changed as markets for various forms of diluents and final product price differentials change.

The second element of this strategy was to support various pipeline initiatives to expand geographic markets. During 2005 we committed to a 25,000 barrels per day shipping agreement on the reversal of the Corsicana line, which will enable us to deliver heavy crude oil directly into the US Gulf Coast. This market is important as much of the heavy crude oil conversion capacity in the United States is located in the region and heavy crude is sold for a premium to what is received in our traditional US Midwest markets. We continue to pursue similar opportunities to other markets in a disciplined manner.

Finally, with respect to the pursuit of increased heavy crude oil conversion capacity, we proposed in late 2005 that we will leverage our technical expertise, project management skills and financial capability, which, coupled with our strong asset base would enable us to build our own upgrader in Alberta. To that end we are currently engaged in a scoping study that will define the location, nature and technologies to be utilized in this project. This proposed upgrader is targeted to be onstream in 2012, and will facilitate an additional 300,000 barrels per day of incremental bitumen production in a stepwise and disciplined manner over the next decade selling a portion of it as light crude oil rather than lower priced heavy crude oil. Capturing substantially more of the heavy crude oil value chain through upgrading not only increases realizations, it also reduces marketing and cash flow risks as it expands markets for the bitumen and eliminates the impact of quality differentials.

HORIZON OIL SANDS PROJECT

This bitumen mining and upgrader project made significant progress during the year following the sanctioning for Phase 1 by our Board of Directors in February 2005. This approval was predicated on a disciplined process in which significant front end

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engineering efforts afforded us the ability to obtain the majority of the Phase 1 construction costs under lump sum bids. This high degree of cost certainty was augmented by an expanded hedging program, which ensured that adequate free cash flow to complete the four year construction effort would be available. While there was an opportunity cost associated with the hedging program, it was the combination of these two elements that enabled the Company to retain a 100% working interest in the Horizon Project without having to compromise on any of our conventional developments.

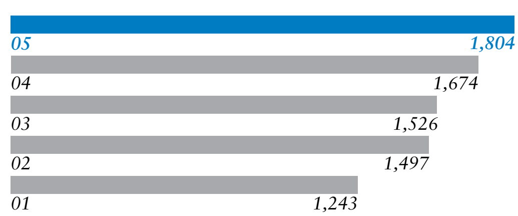
Four years and $400 million worth of front end engineering have provided Canadian Natural with a strong understanding of what we are building and, just as importantly, how we are going to build it. We have forged relationships with a variety of contractors from around the world and together have provided a strong definition of the construction execution plan. Further this high project definition reduces the risks associated with late engineering or "scope" changes which have historically resulted in significant cost revisions for oil sands builders. Finally, we have developed a unique and creative labour strategy that has enabled workers of all labour affiliations from across Canada to participate in the construction effort. This strategy is facilitated through our fly in/fly out capability from our on-site air strip. Today, workers from several provinces in Canada regularly fly to our site and home again on various shifts which accommodate their lifestyles.

Starting from a cleared site of dirt at the beginning of the year, we exit 2005 with approximately 19% of the construction effort completed. Deep underground facilities are installed, many of the footings are in place and much of the large prefabricated units are complete with several already being delivered to site. Although it is still early, we remain on schedule and on budget.

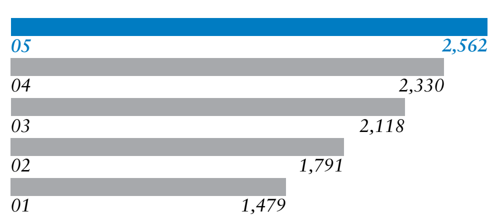
Our lump sum contractors are motivated to seek creative ways to build their portions more effectively. One opportunity identified by them was the exploitation of an expected lull in industry construction activity in 2006 which should make additional workers available to industry. As such, they requested and we approved the acceleration of $400 million of 2007 spending into 2006, as long as they did not deviate from the base requirement of having 80% of engineering completed prior to construction. As a result, we expect to exit 2006 in excess of approximately 55% of the construction effort completed. In all, we remain on budget and on schedule for first oil in 2008.

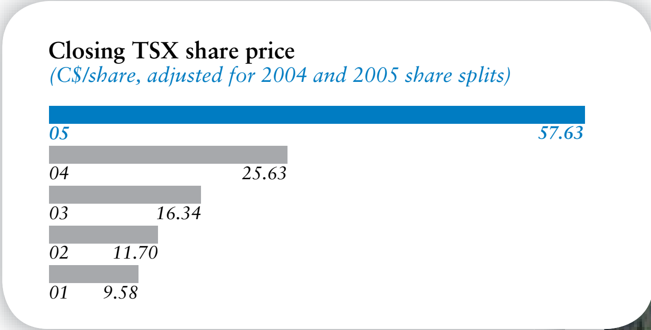
Further, in concert with our in-situ oil sands development plan, we announced the parameters of Phase 4 and Phase 5 expansions of the Horizon Project which will leverage the remainder of our mineable leases. We now target to produce in excess of 500,000 barrels per day of light sweet synthetic crude oil from the Horizon leases by approximately 2017, with no production declines for decades to come. This is truly a world class development opportunity and we intend to follow the same disciplined approach that is currently being utilized on Phase 1.

Company gross conventional proved reserves *(mmboe)*



Company gross conventional proved and probable reserves *(mmboe)*





DEFINED PLAN

The Canadian Natural team is proud to be able to provide a transparent strategy and growth profile to its shareholders. We still target to grow each of our four metrics by an average of 10% per annum and believe that we have the assets to deliver on it.

Financially, we stress tested our plan at US$35 WTI per barrel crude oil prices and would still remain below our targeted financial strength ratios. As such, we do not have to compromise on our basic strategies and retain additional financing capacity should compelling acquisition opportunities present themselves. Of course, as has occurred in the past, our disciplined allocation of capital may result in a shift between organic projects and acquired production as is prudent, should such an opportunity arise.

In addition to the production growth aspect of the plan, the migration of the production mix from one dominated by natural gas and heavy crude oil to one dominated by light crude oil and natural gas means that the economic sustainability of the organization is enhanced throughout the business cycle. Reducing overall exposure to heavy crude oil differentials and avoiding reliance on third parties to develop the markets for our products was a key consideration in our plans. We have taken control of the plan in a financially and operationally disciplined manner and will create a company and defined plan that:

- Leverages the low-cost and lower-risk exploitation nature of the Alberta oil sands with light crude oil netbacks;
- Utilizes an exceptionally large land base/infrastructure to deliver increased natural gas volumes in an economic manner;
- Leverages the exploitation expertise developed in western Canada into the United Kingdom North Sea basin to create new value for shareholders; and,
- Fully exploits the offshore expertise developed in the North Sea, and combined with the strong relationships developed in Offshore West Africa enables us to identify appropriate new exploration and exploitation opportunities in one of the most prolific light crude oil basins in the world.

Management would like to thank our team for continuing to deliver the Plan. We would also like to extend our welcome to new Directors standing for election this year, the Honourable Gary A. Filmon, P.C., O.M., and Mr. Norman F. McIntyre.

We believe that Canadian Natural has the People, the Plan and the Assets to continue to deliver shareholder value for years to come. As a team, we remain committed to "developing people to work together to create shareholder value by doing it right with fun and integrity".

ALLAN P. MARKIN
Chairman

N. MURRAY EDWARDS
Vice-Chairman

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President &
Chief Operating Officer

The People

Excellent people are critical to the success of any organization. The Company strives to achieve a balance of technical skills, leadership, and a strong organizational culture. Even with the rapid expansion of our team, we have retained this balance.

Our technical skills have grown as we have expanded into new basins and products. For example, it was the upgrading expertise and mega-project management skills that we have developed through the Horizon Project that afford us the potential to undertake new initiatives such as the Canadian Natural Upgrader for our in-situ oilsands developments.

These are the people that make our team. Together we deliver the "Plan", converting our strong assets into shareholder value.

Lonnie Abadier, Walday Abeda, Hazel Aberdein-Quirie, Mona Abravesh, Marbella Abuin, Janine Adams, Michael Adams, Steve Adams, Steven Adams, James Agate, Jennifer Ahern, Sarshar Ahmad, Garrisen Ailsby, John Aina, John Aina, Fiona Jean Aitken, Sina Akinsanya, Joseph Albano, Chris P Alderson, Andrew Alexander, Bruce Alexander, Gregory Alexander, Elena Algazina, Mohieddin Alghazali, John Allan, Selena Allan, Jill Allen, John Allen, Simon Allerton, William Allerton, Devin Allibone, Karen Almadi, Eva D Almeida, Gordon Almond, Robert Almond, Jocelyn Alonso, Nelson Alook, Cindy Alpaugh, Ulises Amador, Joann Aman, Clark Ambler, Donald Ames, Sylvia Anaka, Eric Andersen, Grayson Andersen, Jan Andersen, Troy Andersen, Bruce Anderson, Georgina Anderson, Greg Anderson, Jeremy Anderson, Kelvin Anderson, Larry Anderson, Leonard Anderson, Murray Anderson, Paula Anderson, Perri Anderson, Richard Anderson, Peter Andrekson, Janet Andrew, Bob Andrews, Todd Andrews, Sherley Angers, Carolyn Angus, Brian Antoni, Rogerio B Antonio, Kathy Antonishyn, Shelley Antonuk, Jim Archibald, John Argan, James Arkley, Anthony Armstrong, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Paul Arsenault, Niels Arveschoug, Jim Asmus, Jacqueline N'Goran Asso, Sialla Victoire Assohou, Francklin Assoko-Mve, Maguy Aude Atheba, John Atkinson, Nicole Atkinson, Gordon Au, Maurice Aubin, Jason Auch, Bernard Auger, Richard Augustyn, Colin Avison, Eustace Azim, Adrian Baciulica, August Baier, Dave Baier, Janice Baik, Michael Baik, Dwayne Bailer, Rod Bailer, Leon Bakaas, Chris Baker, Sharon Baker, Patricia Bakker, Reginald Baldock, Christopher Baldwin, Mark Baldwin, Vaughn Baldwin, Joel Balkam, Colin Ball, Gary Ballas, Ronnie Ballas, Sheldon Ballas, Mamadou Bamba, Neville Banak, Darwin Banash, Rechelle Baniqued, Bob Banks, Teresa Banny, Inge Bantli, Garry Bardoel, Larry Bardoel, Pamala Bare, Sharon Barker, Stephen Barker, Michael Barnes, Javier Baroja, Kenneth Barrett, Phrona Lisa Barrett, Darcy Barry, Carol Barss, Marty Bartman, Sonia Basati, Julius Bascon, Calvin Bast, Cheryl Bateman, Lisa Bateman, Selena Bath, Brenda Battyanie, Jackie Bauer, Kevin Bauman, Juan Bavaresco, Veronica Bayley, Colin Beaman, Chad Beaton, Aura Beattie, Laurier Beaunoyer, David Bechtel, Chris Becker, Elke Becker, Gurpreet Bedi, Ewan Beenham, Adrian Begley, Loren Behrens, Guy Belanger, Lesley Belcourt, Betty Belenky, Calvin Bell, David Bell, Faye Bell, Jon Bell, Larry Bell, William Bell, Reg Bellanger, Lorne Bellows, Remie Belmonte, Ahmed Bendahmane, Khalida Bendahmane, Brad Bendick, David Bendrey, David Bennington, Shelly Bensmiller, James Bentley, Linda Beresh, Debbie Berg, Lorn Berg, William Berg, Jeffrey Bergeson, David Berlinguette, Henry Berlinguette, Joanne Berrade, Murray Bertsch, Jonathon Best, Stewart Bettinson, Bob Bezpalko, Marc Bickham, Jennifer Bidlake Schroeder, Douglas Bielech, Inge A Biener, Bruce Bignell, Rhett Binding, Roger Bintz, Warren Birch, Tim Bird, Hope Bishop, Travis Bishop, Paula Bissell, Peter Bissell, Darwin Bittner, Kevin Bjornstad, Adam Black, Chad Black, David Black, Jennifer Black, Kenneth Blackhall, Kerri Blackmore, Michael Blair, Deana Blais, David Blake, Christopher Blatchly, Parrish Blizard, Ellen Bloomfield, Robin Bly, Allan Boddy, Brad Bodnar, Dennis Boehmer, Michael Boer, Kent Boerrichter, Darcy Boettger, Marty Boggust, Gordon Bohrson, Paul Boileau, Claude Boily, Peter Boisvert, Michael Bolianatz, Greg Bolin, Greg Bolton, Patricia Booklall, Jayne Booth, Karen Booth, Jack Bootsman, Charlene Boraas, Barry Borbely, Adriana Borbon, Albert Bordeleau, Michael Born, Jon Borstel, Prasanta Borthakur, Dave Bosch, Dave Bosek, Greg Boshaw, Keith Bottriell, Suzanne Boudignon, Kari Bouillet, Sheldon Bourassa, Daryl Bourque, Jason Bowers, Jim Bowers, Slade Bowers, Dale Boychuk, Doug Boyd, Patrick Boyd, Randy Boyd, Charline Boyer, Neil Bozak, John Brabec, Dave Bracey, Bryan Bradley, Peggy Bradner, Jan Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Ralph Brand, Myron Brataschuk, Brad Braun, Colin Brausen, Vincent Breaker, Tara Brechin, Tara Brechin, Sharon Breitkreuz, Leonie Breitling, Joseph Breland, Paul Breland, Roxane Bretzlaff, Denis Brisebois, Robert Brisson, Shawn Brockhoff, Kelly Broda, Brian Brodbin, Ashley Broderick, Dwayne Brodziak, Katherine Brogden, John Brogly, Bill Bromling, Murray Brooker, Dennis Brooks, Carla Brown, Darren Brown, Jeremy Brown, Steve Brown, Robert Brownless, Elizabeth Brownrigg, John Brule, Gordon Bryant, Stewart Buchan, William Buchan, Anna Bucior, Linda Bucke, Natasha Buckland, Gordon Buckshaw, Linda Buczkowski, Malcolm Budd, Raymon Bueckert, Ryan Bulger, Ian Bulloch, Clarence Bur, Trevor Burchenski, Ian Burchette, Jeffrey Burdett, Brent Bureau, Heather Bureau, Keith Bureau, Grant Burgess, Alastair Burke, Crystal Burke, Gayle Burnett, Wendy Bursey, Gerald Burtch, Corinne Burton, Lisa Bush, Rosemary Bussi, Terry Butchart, Jim Butler, Bob Butterworth, Ronald Butts, Leanne Butz, Tricia Butz, Mike Byrtus, Irina Byvald, Joe Cabay, Mark Cadman, James Cadrain, Simon Cains, Laura Calder, Leslie Calder, Patrick Caldwell, Thomas Callaghan, Richard E Calliou, Lynn Callsen, Dean Cameron, Mike Cameron, Rory Cameron, Shirley Cameron, Tavis Cameron, Catherine Campbell, Clayton Campbell, Dean Campbell, Doug Campbell, Earl Campbell, Nancy Campbell, Robert J Campbell, Shawn Campbell, Valerie Campbell, Andre Campeau, Gregory Cane, James M Capjack, John Capstick, Kathleen Carbury, Fred Cardinal, Harley Cardinal, Lee Cardinal, Sharon Cardinal, Wayne Cardinal, Jim Carey, Mary-Ann Carey, Ian Carleton, Wes Carlson, Daryl Carlton, Leslie Carlyle-Ebert, Albert Caron, Murrey W Carpendale, Kim Carrol, Eduardo Cartaya, Marilyn Carter, Gary Case, Mary-Jo Case, Trevor Cassidy, Mike Catley, Steve Caven, Tom Cegielny, Marco Celis, Samuel Cervantes, Sachi Chakravarty, Mark Chalmers, Erin Chamberlain, Joe Chamberlain, Cynthia Chambers, Katrina Chambers, Lise Champagne, Alan Chan, Anly Chan, Jack Chan, Jik Chan, Sarah Chan, Tim Chan, Christina Chang, Calvin Chapman, Melody Chapman, Todd Chapman, Deon Chappell, Harry Chappell, Darryl Charabin, Cynthia Chartrand, Susan Y Chase, Leon Chateauneuf, Siddique Chaudhry, Dawn Chau-Lam, Gary Chaulk, Jackson Chaves, Rinet Maria Chaves-Thissen, Jacinto Cheng, Mike Chernichen, Brian (Chuck) Cherry, Albert Cheung, James Cheung, Sherry Chiang, Gloria Chick, Patricia Childs, Melaine Chin, Sharon Chin, Jamie Chisholm, William Chiverton, Randall Chodzicki, Jessica Choi, Raymond Chong, Wayne Chorney, Lynn Chotowetz, Sherry Chow, Daryl Chrapko, Alphonse Chretien, Ruth Christensen, Marianne Christianson, Steven Christie, Rob Christopher, Andy Chu, Ken Chudleigh, Sharon Chung, Heather Church, Ronni Church, Kadidiatou Cisse, Magda-Christina Ciulavu, Michael Clapham, Bryan Clapperton, William Clapperton, Amanda Clark, Andrea M Clark, Evan Clark, Janice Clark, Evan Clarke, Martha Clarke, Olivia Clarke, Sanja Clarke, Shandon Clarke, William J Clarke, Walter Clarkson, Greg Clegg, George Clutton, Brooke Coburn, Dale Coburn, Judith Cochran, Sabrina Colangelo, Martin Cole, Robin Coles, Elva Coley, Curtis S Collins, Rod Collins, Royston Collison, Ronald Compton, David Conybeare, Brad Cook, Brian Cook, Christopher Cook, Anna Cooke, Bill Cooke, Gary Coombe, Kent Cooper, Tammy Cooper, Jean Corbiere, Elaine Coreman, Rosetta Cormier, James Corner, Rosario Corral, Luis Correal, Jim Corson, Lorenzo Cortes, Neil Cortmann, Harry Costello, Neil Costeloe, Douglas Coull, Kim Coulter, Jack Courchene, Kathryn Courtney, Julie Cousineau, Dave A Cousins, James Coutts, Gordon Coveney, Richard Coward, Keith Cowger, Catherine Cowie, Jonathan Cox, Randy Cox, Wade R Cox, Nigel Crabb, Harry Crabtree, Layne Craig, Ryan Craig, Bruce Crain, Allen Crawford, Bryan Crawford, Marina Crawford, Paul Crawford, Beverley Creed, Leanne Cressman, Donald Cretney, Roger Crichton, David Cridland, Stefan Croft-Bednarski, Christopher Cross, Lloyd Cross, Camille Croteau, Philip Cruickshank, Linda Cruttenden, Anthony Csabay, Will Csanyi, Jeff Cullen, Corinna Culler, Francesca Cultrera, Darrel Cunningham, Davis Cunningham, Arley Currie, David Currie, Brent Curtis, Paul Curtis, DaleS Cusack, Kenneth Cusack, Pat Cusack, Réal Cusson, Midge Cuthill, Don Cutting, Ken Cyr, Andre C DaCosta, Helder J DaSilva, Ivone Elma Malaquias DaSilva, Victor Daboin, Greg Dacyk, Fakhri Dadashov, Gary Dahl, Hamid Dahmani, Eliane Dakaud, Trevo D Dales, Joey Daley, Layne Dalgetty-Rouse, Walter M Danchak, Gene Danyluk, Peter Danyluk, Alan Dar, Eric Dargis, Lynne Darlington, Wigo Dascalescu, Graham Davidson, Marie Davidson, Philip Davidson, Tim Davidson, Todd Davidson, Frank Davis, Graham Davis, Randall Davis, Robert Davis, Sarah Davis, Jeffrey Davison, Peter Davison, Leonard Dawe, Robert Day, Eric de Kock, Douglas De Avila, Ryan De Bruyne, Phil De Gagne, Ryan De Leeuw, Lance De Meillon, David Dean, Harry Dean, Derek Dechaine, Raymond Dechaine, Roland Dechesne, Sheldon DeFord, Mervin J Degenstien, Barbara Deglow, Daniel L Deiana, Bonnie Deis, Natalie Delfs, Gabriel Deliu, Franco Dell'Ovo, Benita De Lorenzo, Brent Delorme, Michael Delorme, Fiona Dempster, Susan Dennis, Shirley Denny, Edward Deren, Tom Dereniwski, Semir Dervovic, Eugenie Dery, Travis Desilets, Michael Des Roches, Laurie A Devey, Wendy De Visser, Robert Dewis, Karen Deyaegher, Vikas Dhawan, Aldo Di Flumeri, Karim Mounian Diallo, Harry Diamantopoulos, Sumara Diaz, Daniel Diaz-De-Leon, Catherine Dicken, Robert Dicken, Garry Dickie, Cameron Dickson, Irene Dikau, Anne Dillon, Michael Dingley, Ashley Dinkel, Ronald Dinkel, Hubert Dinn, Issiaka Diomande, Gayle Dionne, Al Dixon, Kathleen Dixon, Trent Dixon, Denise Dixson, John Dmetruik, Angela Dobb, Leanne Dobson, Linnae Dobson, Edward Dochuk, Alistair Dodds, John Dodman, Erin Doepker, Kelly Doepker, Ritchie Doering, Patrick Dolan, Amy Dolomount, Conrad Dombowsky, Kelly Dombrosky, Brenda Dombrova, Manuel P Domingos, Dan Domke, Kyle Donald, Scott Donaldson, Tim Donkersloot, Tim Dootka, James Doran, Allen M Dorey, Cecill Dorey, Mathieu Dorval, Olga Dost, Réal Doucet, Edward Douglas, Dahl Dow, Angela Dowd, Phil Downes, Wayne Draper, Don Drindak, Colleen Drury, John Drury, Steven Drysdall, Calvin Duane, Laurie Dube, JoAnne Dubeau, Renee Dubeau, Jeramie Ducharme, Albert Duczek, Jon Dudley, Rhonda Dudley, Simon Dugdale, Douglas Duguid, Albert Duhaime, Cheryl Dumais, Barry Duncan, Lois Duncan, Sean Duncan, Dale Duniece, Graham Dunlop, Jill Dunlop, Robert Dunn, Andrew Dunne, Judy Dunsmuir, Lyle Dupuis, Dariela Duran, Harvey Dutchak, Diane Duthie, Eugene A Dyjur, Krzysztof Dzwonek, Gary Earl, Kevin Earle, Julie Easthope, Suzanne Eaton, Sean Ebert, Jim Eby, Greg Ecker, James Edens, Robert Edgar, Josephine Angie Edoukou, Gordon Edward, Dave Edwards, Susan Edwards, Fred Eefting, Cindy Egden, Nicole Eitzen, Devin Ekdahl, Wassim El Chayati, Douglas Elder, Carole Eliuk, Anthony M Ell, Mohamed El-Naas, Jerry Enders, Rommel Engler, Joanne English, Chris Erickson, Terry Erickson, Kresten Eriksen, Kenl Erker, Polina Ersh, Rick Estrada, Dave Evans, Lee Evans, Tim Evans, Leila Eveleigh, Maureen Evers-Dakers, Clayton Eves, Adrian R Ewasiuk, Laura Ewen, Douglas Eynon, Leonard Fabes, Lawrence Facchina, Denis Fagnan, Heather Fahey, Catherine Falconer, Andy Fankhauser, Travis Farrer, Ravinder Farwaha, Stefa Fassina, Arthur Faucher, John Fay, Karman Fayant, Tanya Fayant, Brian Fehr, Darwin Feil, Ira C Feland, Maria H Felix, Andre Yves Felix Tchicaya, Kurt Fenrich, Randy Fenton, Ken Ference, Brad Ferguson, Helen Ferguson, Mark Ferguson, Roy Ferguson, Scott Ferguson, Mario Feria-Estrada, Joaquim Fernandes, Cory Fernets, Darren Fichter, Tiziana Ficocelli, Alan Fiddes, Jane Fielding, Michael Filipchuk, Natalie Filippini, NeilA Findlay, Kelly Finigan, Bob Finlayson, Chad Finnebraaten, Tanya Fir, John Fisera, Calvin Fisher, David Fittkau, Bill Fitzgerald, Sandra Fitzpatrick, Paul Flanders, Ken Fleck, Sean Fleming, Rodney Flett, Trevor Flood, Edmond Foisy, Justin Foisy, Ryan Folkerts, Gregory Fontaine, Robert Fontaine, Roger Fontaine, Lynn Foo, Harris Foote, Adele Forcade, Curtis Formanek, Randy Formanek, Devon N Fornwald, Leslie Forrester, Alastair Forsyth, Alstair Forsyth, Brenda Forsyth, Chantal Fortin, Gilles Fortin, Thomas Fortin, Donald Foster, Dwayne Fotty, Kevin Foulds, Lise Fournier, Neil Fowler, Peter Fowler, Donald Fox, Donna Frame, Joao A Francisco, Ron Frank, Shelley Franssen, Leonard Fraser, William Fraser, Barry Frazer, Ken Frazer, Ted Frederickson, Michael Freeman, Stacey Freidin, Tammy J Fremont, Roger Frere, Kurt A Freyman, Brad Friesen, Kenneth Friesen, Tracy Frith, Andrei Frizorguer, Frank Frosini, Scott Froude, Karen Fujimoto, Jim Fung, Sarina Fung, Ted Furuya, Don Gabruck, Josephine Gaddi, Leonard Gadowski, Sharon Gaehring, Kelly Gagne, Larry Galea, Ron Gall, Michael Gallon, A William Galloway, Carmen Galue, Yoko Galvin, Bob Gandhi, Carlos Garcia, Doug Gardner, Jon Gareau, Glen Garton, Stan Garwon, John Gates, Joseph Gaugler, Maurice Gauthier, Neil Gauthier, Steve Gavronsky, Paul Gazzard, Alain Gbo, Michael Geldert, David Geleta, Lesley-Ann Gemmell, Neil Genge, Patricia Gentles, William George, James Georget, Matthew Gering, Grant Gerla, Michel Germain, Raymond Germain, Robert Germain, Albert Gervais, Marc Gervais, Paul Gervais, Bob Gerwing, Sheldon Getson, Beryl Gettings, Clark Getz, Glen Getz, Ken Getzinger, Zoheir Ghaddar, Douglas Gibson, Charles Giddings, Jean Giesbrecht, Todd Giesbrecht, Dwayne Giggs, Laura Giggs, Elias Gildeh, Tamara Giles, Gladwin Gill, Perry Gillam, Jeremy Gillespie, John Gillespie, Sharen Gillett, Janna Gillick, Sandra Gillis, Justin Gilmour, Scott Gilmour, Douglas Ginn, Anna Giove, Stewart Girbav, Ben Gisby, Eugenio Giuliani, Marvin Gladue, Russell Gleed, John Glennon, Duane Goetz, Peter Goetz, David Golden, Cody Gomuwka, Brian Gonsalves, Yvonne Gonzalez, Ian Gordon, James Gordon, Wendy Gordon, Winston Goretsky, Yvon Gosselin, Allan Gould, Todd Gould, Antonella Goulet, Sandra Goundrey, Carl Graham, Pamela Graham, Stephanie Graham, Harry Grant, Allissa Gray, David Gray, Ronald Gray, Sheila Gray, John Greaves, Linda Green, Theresa Greene, Ernie Greenwood, Lisa Gregg, Derek Greidanus, Clint Greschner, Edmond Griffiths, Leo Groenewoud, Robert Grover, Wayne R Gruhlke, Daryl Grundner, Neil Guay, Trevor Guay, Cesar Guercio, Don Guglielmin, Gilbert Guigon, Robert Gullion, Shane Gullion, Swarna Gunaratne, Carolyn Gunderson, Alan Gunst, Ashok Gupta, Rustam Guseynov, Edward Gushnowski, Terry Gusnowski, Elaine Gussman, Graham Gustafson, Harold Gutek, Fabio Gutierrez, Bartley Haahr, Violet Haddad, Resad Hadzismajlovic, Keri Hagemann, Egbert Hagens, Chad Hagstrom, Keith Hague, Sam Hajar, Shemin Haji, Zohreh Hajibeygi, Dan Halaburda, Montie Hale, Dean Halewich, Eric Haley, Rick Halkow, Barry Hall, Charles Hall, Donald Hall, Kathy Hall, Shane J Hall, Todd Halladay, Patricia Halldorson, James Hallett, Robert D Hallett, Charlene Halter, Larry Hamende, Jeremy Hamilton, Tim Hamilton, Kevin Hamm, Michael Hammel, Larry Hammell, Rick Hammond, Chrystal Hamori, Elaine Hampton, Brad Hancock, Anne Hand, Carol Handley, Shane Handsaeme, Tracy Hanline, Karl Hann, James Hansen, Ole Hansen, Todd Hansen, Judy Hanson, Leland Hanson, Brent Harbin, Leon Harder, Kent Hardisty, Ken Harke, Brent Harle, Leslie Harley, Angela Harlos, Erik Haroldson, Bill Harris, Chad Harris, Jody L Harris, Murray Harris, Roger Harris, Ron Harris, Clayton Harrison, Dylan Harrison, Randy Harsany, James Harty, Mike Harty, Janet Harvey, Jerry Harvey, Julie Harvey, Robert Harvey, Cory Harvie, Cheryl Hasenclever, Colin Hastings, Iain Haston, James Haston, Ewen Hatchwell, Bryan Hattebuhr, Christine Hattebuhr, Dale Hattebuhr, Helen Hattie, Barret Hatton, Wayne Hatton, Dave Haub, Dave Haub, Willow Hauber, Wayne Hausch, Lew Hayes, R Joey Hayward, David Haywood, Sean Head, Jay Heagy, Larry Heath, Brian Hebert, Gerald Hebert, Terry Heck, Ken Hedstrom, Della Hefford, Sherrie Heil, Robin Hein, Raymond Heisz, Mahmud Hejni, Greg Helman, Barton Henderson, Steven Hennessey, John Hennessy, Leona Hennig, David Henry, Jackueline Herauf, Kim K Herbst, Sheri Herman, Judith Hermann, William Hernandez Paredes, Darryl E Herner, Luis Herrera, Coreen Herring, Keith Heslop, Andrew Higgins, Rachelle Higgins, Tyla Higgs, Charlene Hill, Gordon Hill, Marie Ellen Hill, Steve Hill, Jesse Hillebrand, Laureen Hillebrand, Jeff Hillier, Christie Hillis, Arnold Himschoot, James Hinde, Jim Hlewka, Margaret Ho, Donald Hoar, Barry Hodgan, Gary Hodge, Barbara Hofer, Miles Hogaboam, Joanne Hogg, Kevin Hogg, Krista Hogg, Kevin Hoium, Donald Holley, Doug Holman, Richard Holman, Donald Holmen, Cliff Holmerson, Chris Holmes, Ian Holmes, David Holt, Kim Holtby-York, Clayton Holthe, Dennis O Holthe, Shannon Hood, Hans Hoogendam, Blaine Hook, Graham Hook, Keith Hornseth, Camelia Horvath, Lance Hoskyn, Helena Houghton, Sherri Houle, John Howard, Trapper Howard, Kristy Howe, Kim Hranac, Jianxin Huang, Joanne Huang, Michael Hudgins, Paul Hudson, Sandy Huebner, David Huff, Jeremy Hughes, Mark Hughes, Eun Ju Huh, Wayne Hui, Bryan Huk, Riley Hull, Terry Humbke, Manpreet Hundal, Jennifer Hunt, Kevin Hunter, Robert A Hunter, Tom Hunter, Vivian Hunter, James Hurdal, Bradley Hurtubise, Glenn Hussey, Daniel Hutchinson, Dennis Hutchinson, Myrna Hutchinson, Ray Hutscal, Bruce J Hutt, Greg Huva, Stephen Hygard, Bonnie Hynes, David Hynes, Scott Hyrcha, Sarah Hyslop, Matthew Ilchuk, Detlev Imorde, Dominic Ing, Jennifer Inglis, Brad Inman, Rebecca Innes, Jamieson Irons, Jeff Irons, Dora Irsa, Darren Isele, Khalid Ishaq, Floyd Isley, Karen Ivan, Jeff Iwanaka, Nicholas Jack, Wallace Jack, Allen Jackson, Daniel Jackson, Judy Jackson, Kevin Jackson, Russel Jackson, Victoria Jackson, Ken Jacobs, Ken Jacobson, Albert Jacula, Curtis Jacula, Irene Jacula, Todd Jacula, Hamid Jafari, Charu Jain, Vivek Jain, Michael Jaindl, Boris Jakulj, Annie Jalotjot, Chris James, Bob Jamieson, Nigel Jamieson, Maria Jancewicz, Marc 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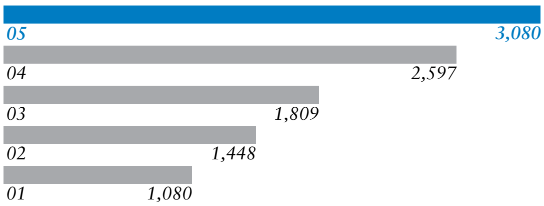

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Wetzstein, John Wham, Terence Whang, Loyd Wheating, Joshua Wheaton, Andrew Wheeler, Bob W Wheeler, Francis W White, Gail White, Julie White, Ken White, Ralph White, David Whitehouse, John Whitlock, Grant Whittemore, Michael Whittingham, Heather Whynot, Jane Whyte, Blaine Wicentovich, David Wiebe, Debbie Wiens, Cameron Wietzel, Cheryl Wiggett, Zandra Wigglesworth, Bob Wilbern, Brandon Wild, John Wilding, Daryl Wiles, Troy Wilk, Melanie Wilkie, Amy Wilkinson, Derek Wilkinson, Elmer Willard, Shannon Willcott, Bill Williams, Grant Williams, Greg Williams, Julian Williams, Kelvin Williamson, Monty Williamson, Jeff Willick, Kennneth Willis, Robin Willis, Wayne Willis, Susan Wills, Christian Willson, Curtis Wilson, Don Wilson, Ian Wilson, James Wilson, Jeff Wilson, Marty Wilson, Patrick Wilson, Tammy Wilson, Tyler Wilson, Woodrow Wilson, Joan Wilton, Bob Wing, Ken Winsborrow, Noel Winter, Greg Winters, Garrett Wirachowsky, Jeff Wiseman, Morrison Wiseman, Paul Wiseman, Dale Wittman, Kelly Woidak, Colin Woloshyn, C K Bill Wong, Jason Wong, Jennifer Wong, Lisa Wong, Steve Wong, E Bette Wood, Leonard Wood, Philip Wood, Roxanne Wood, Laura Wooding, Travis Woods, Marilyn Woodske, Wayne Woodward, Sidney Wosnack, Raymond Wourms, Mark Woynarowich, Chris Wright, Daniel Wright, Richard Wright, Bin Wu, Christine Wutzke, Brent Wychopen, Guy Wylie, George Wyndham, Brent Wyness, Barry Wynne, Valerie Wyonzek, Cameron Yamada, Canghu Yang, Grace Yang, Lin Yang, Andrew Yaremko, Rick Yarmuch, James Yaroslawsky, Jeff Yates, Noah Yates, Betty Yee, Davin Yee, Gordon Yee, Michael Yee, WSelina Yeung, Jeffrey Yip, Kitty Yip, Darrell York, Rachelle Yorke, Daryl Youck, Bill Young, Chalene Young, Clayton Young, Kelly Young, Richard Young, Wendell Young, Ray Yowney, Clement Yuen, Dustin Yuill, Jeff Yuill, William Yuill, Arina Yuzhakova, Robin Zabek, Robert Zabot, Gabriel Zachoda, Tyler Zachoda, Cam Zackowski, John E Zahary, Attila Zahorszky, Mark Zan, Glenn Zeebregts, Patricia Zegers-de-Beyl, Lynn Zeidler, Tony Zeiser, Aleksandra Zelic, Diane Zeliznik, Grant Zellweger, Darcy Zelman, Denis Zentner, Kathy Zerr, Michelle Zerr, Xu (Frank) Zhang, Wanli Zhu, Evgeny Zhuromsky, Brenda Ziegler, Dwayne Zilinski, Hernando Zorrilla, Ana Zulueta, Bob Zulueta.

The Plan

We have a strong track record of setting a plan and diligently delivering against it. That being said, we remain flexible to react to market changes or take advantages of opportunities as they arise.

Review of Operations

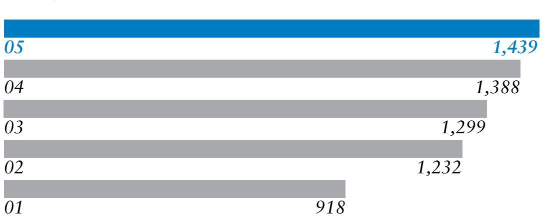
PRODUCTION STRATEGY AND RESULTS

Canadian Natural has increased its hydrocarbon production and reserves each and every year since becoming an independent producer in 1989. Throughout that 17 year period we have adhered to the same basic business formula - maintain large project inventories in every product and basin in which we participate. Large project inventories enable the Company to continually high-grade the capital allocation process and balance production mix among each of the commodities we produce; namely natural gas, light crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

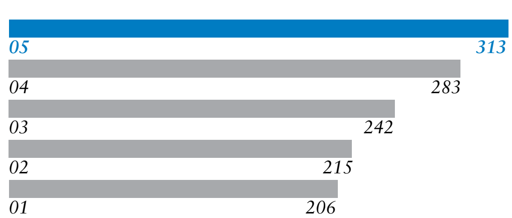
In 2005 we again achieved record levels of production on a barrel of oil equivalent basis. Production before royalties on a barrel of crude oil equivalent was 553 mboe/d during 2005, up 8% from 2004 levels and was achieved primarily through a combination of exploration and asset development. Natural gas production before royalties increased by 4% and continues to represent our largest product offering. Total crude oil and NGLs production before royalties increased by 11%, with the primary drivers being the commencement of production from the Baobab Field located offshore Côte d'Ivoire and improvements in production from North Sea light crude oil, Pelican Lake crude oil and the Primrose in-situ oil sands development.

	2005		2004	
(before royalties)	Production mboe/d	Mix %	Production mboe/d	Mix %
Natural gas	240	43	231	45
North America light crude oil and NGLs	52	10	47	9
Pelican Lake crude oil	23	4	20	4
Primary heavy crude oil	93	17	95	19
Thermal heavy crude oil	53	10	44	8
North Sea light crude oil	69	12	65	13
Offshore West Africa light crude oil	23	4	12	2
Total	553	100	514	100

Daily natural gas production, before royalties
(mmcf/d)



Daily crude oil and NGLs production, before royalties
(mbbl/d)



THE PEOPLE

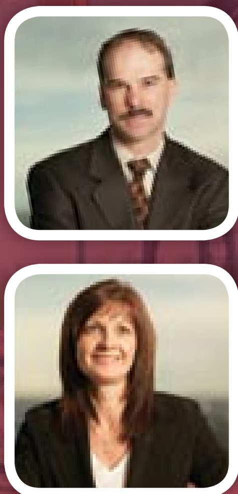
Our technical skills are strong and our people are motivated.

THE PLAN

Our exploitation approach is flexible to accomodate changes in our operating environment.

THE ASSETS

We have exposure to many play types, through ownership of one of the largest landholding positions in the WCSB.



TIM S. McKAY
Senior Vice-President,
North American
Operations

MARY-JO E. CASE
Vice-President, Land

GEO-SCIENCE STRATEGY

We believe that a disciplined focus on geology and geophysics reduces exploration risk and ultimately results in better full cycle economics. We drill hundreds of wells each year and add new high quality locations to our inventory by integrating geological plays with seismic data analysis. The achievements of our experienced team of geologists and geophysicists is reflected in our quality results.

Canadian Natural continues to be active in adding quality locations to its inventory by integrating geological plays with seismic data analysis. In Canada, we invested $96 million during 2005 to acquire new seismic and to purchase and reprocess existing seismic data. In total, over 4,389 kilometers of conventional 2-D seismic data and over 430 square kilometers of 3-D seismic data were acquired. Additionally, over 12,577 kilometers of conventional 2-D seismic data and 986 square kilometers of 3-D seismic data were purchased. We continue to acquire this data under stringent environmental controls and in a cost effective manner.

In the North Sea, we purchased 2,800 square kilometers of 2-D seismic and reprocessed a further 64 square kilometers of 3-D seismic data. This data allows us to continue aggressive in-field and near-field development and exploration. Offshore West Africa saw the acquisition of 2,400 kilometers of proprietary 2-D seismic data and the purchase and reprocessing of 1,530 square kilometers of 3-D seismic data.

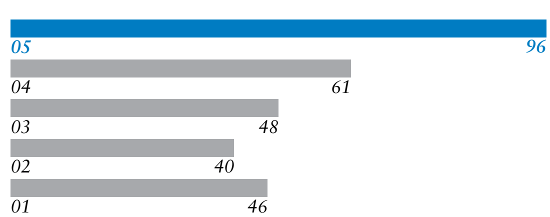
STRATEGIC LAND BASE

Canadian Natural has the second largest undeveloped land inventory in the WCSB. At the end of 2005, our Canadian undeveloped net acreage totaled 10.9 million net acres. Total landholdings were 16.6 million net acres at the end of 2005, up slightly from 2004.

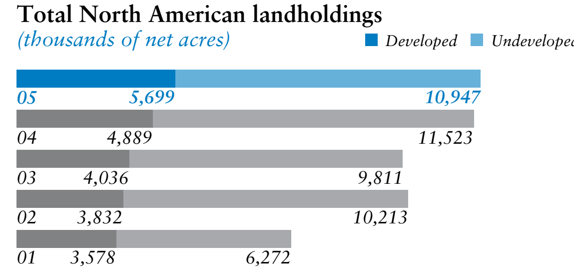
This strong concentrated land base affords significant opportunities to maintain our low finding and onstream costs and low operating costs. The vast majority of our land base is positioned to utilize existing owned and operated infrastructure and it also strategically positions us to maximize the benefit of new play types developed by ourselves and other producers adjacent to our core operating areas.

We can also lever newly discovered opportunities into upside potential for our existing lands or into acquisition of competitor lands. As an example, in late 2003, we leveraged our vast Northeast British Columbia land base to correlated well data to develop a new regional shallow natural gas play. In 2005, production from this shallow play reached 35 mmcf/d.

Seismic expenditures in Canada
($ millions)



Total North American landholdings
(thousands of net acres)



The infrastructure associated with this vast, concentrated land base also provides a competitive advantage in terms of lower marginal operating and development costs for newly drilled or acquired properties. This dominance can create property acquisition opportunities, as we maintain a low-cost regime and access to infrastructure.

Internationally, our North Sea net undeveloped acreage remained strong while Offshore West Africa net undeveloped lands decreased following the sale of leases held in Angola as partially offset by the acquisition of lands in Gabon.

The Company's overall average landholding working interest of 82% reflects the Company's philosophy to maintain high ownership levels and control operations. Assets are better developed and exploited according to the Company's own plans and timelines. This flexibility allows the Company to maintain discipline in its capital expenditures. For example, in 2004 as a result of capital allocated to strategic property acquisitions, the Company inventoried many of its planned 2004 drilling locations for future years.

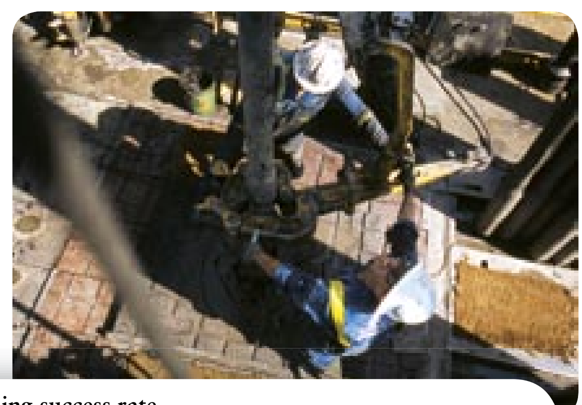
CORE LANDHOLDINGS

	2005			2004		
(thousands of acres)	Gross	Net	%	Gross	Net	%
North America						
Developed	7,184	5,699	79	6,577	4,889	74
Undeveloped	13,163	10,947	83	14,051	11,523	82
	20,347	16,646	82	20,628	16,412	80
North Sea						
Developed	138	93	67	138	93	67
Undeveloped	457	352	77	830	565	68
Offshore West Africa						
Developed	7	4	58	8	5	59
Undeveloped	521	426	82	1,672	886	53
Total						
Developed	7,329	5,796	79	6,723	4,987	74
Undeveloped	14,141	11,725	83	16,553	12,974	78
	21,470	17,521	82	23,276	17,961	77

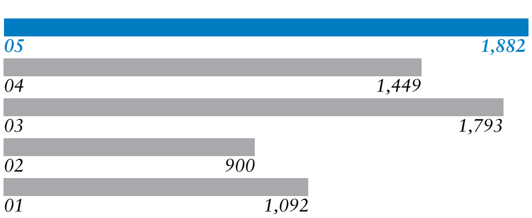
DRILLING ACTIVITY AND STRATEGY

During 2005, we completed the largest drilling program in the Company's history, a total of 1,882 wells or 30% more than in 2004. Our drilling success rate of 93% improved slightly over the prior year and reflects the low-risk exploitation approach that we take to the business.

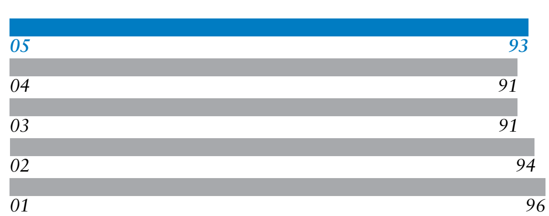
In 2005 our drilling plans were the most comprehensive we have ever prepared in Canada, including an organized migration of rigs to optimize utilization and better balance drilling activities throughout the year. We leveraged that plan and our extensive drilling inventory to its fullest extent due to weather. Warmer than normal winter weather in 2005 led to an earlier spring breakup for winter access areas and a much wetter than normal summer was followed by a late freeze up for the 2005/6 winter drilling season. This meant that our execution had to be flexible and had we not developed such a comprehensive plan with an extensive prospect inventory, it would have been a challenge to complete the majority of the program in an economic and disciplined manner. The merits of this discipline and planning are reflected in our finding and onstream cost control.



Total net wells drilled



Drilling success rate, excluding stratigraphic test/service wells
(%)



For 2006 we plan to take our comprehensive drilling plans one step further and design the drilling program to optimize the capabilities of the drill rig contracted for the area. That is, while some rigs may be capable of a wide range of applications, there is generally a range of depths in which the rig is at its optimum efficiency. We will target wells that have depths or other requirements that fit within these optimum efficiencies. This will help ensure that every dollar spent is generating maximum value. Those wells in inventory that do not fit into the criteria for the drill rig in 2006 will be re-inventoried for drilling in a future year when the most efficient rig type is available in that area.

Year Ended December 31	2005			2004	
	Gross	Net	Success	Net	Success
Crude oil					
North America					
Light oil	107	81	92%	45	97%
Pelican Lake	83	83	99%	34	100%
Primary heavy oil	369	341	94%	180	96%
Thermal heavy oil	107	107	98%	58	100%
North Sea	13	12	87%	9	82%
Offshore West Africa	6	3	85%	2	77%
	685	627	95%	328	97%
Natural gas – North America					
Northeast British Columbia	230	201	88%	167	89%
Northwest Alberta	184	152	92%	138	92%
Northern Plains	240	199	84%	163	80%
Southern Plains	417	338	99%	221	95%
	1,071	890	91%	689	89%
Dry	136	117		96	
Subtotal	1,892	1,634	93%	1,113	91%
Stratigraphic test / service wells	251	248		336	
Total	2,143	1,882		1,449	

North American crude oil drilling increased substantially from 2004 levels when capital was reallocated following four major property acquisitions. The largest increase in drilling occurred on primary heavy crude oil projects where activity was ramped by over 90%. This was reflected in associated production volumes which increased from approximately 92 mbbl/d in the first quarter to over 96 mbbl/d in the fourth quarter. Drilling at Pelican Lake increased by 50 net wells or 147% due to increased activity associated with enhanced oil recovery schemes and additional primary production potential that continues to expand our developable land base. Associated production at Pelican Lake increased from approximately 18 mbbl/d in the first quarter to over 28 mbbl/d in the fourth quarter. Thermal drilling activity increased 90% reflecting the development of the North Primrose Field which commenced production in early 2006.

Natural gas drilling activity also increased in each of our core regions and by 26% overall when compared with 2004 levels. Drilling in Northeast British Columbia increased with 26% more wells being drilled across a variety of depths and geological structures. In Northwest Alberta, 76 net Cardium wells were drilled versus 69 in 2004. In the Plains increased activity was associated with coal bed methane gas with 100 net wells drilled and shallow gas with 209 net wells drilled.

During the year, 126 net stratigraphic wells were drilled on our oil sands mining leases and 95 were drilled on our conventional leases to delineate resource potential. A total of 27 net service wells were drilled including 25 wells in North America and 2 wells internationally.

ACTIVITY BY CORE REGION

	Net Undeveloped Land (thousands of net acres)		Drilling Activity (net wells)	
	2005	2004	2005	2004
Northeast British Columbia	2,027	2,040	241	192
Northwest Alberta	1,507	1,660	183	156
Northern Plains	6,594	6,922	907	613
Southern Plains	621	661	354	240
Southeast Saskatchewan	82	123	52	13
Horizon Oil Sands Project	116	116	126	218
United Kingdom North Sea	352	565	14	14
Offshore West Africa	426	886	5	3
	11,725	12,974	1,882	1,449

THE PEOPLE
Our people understand our customers and have creatively found ways to expand the markets we sell to.

THE PLAN
We seek to maximize market potential for every product we sell. In particular, we leverage our 3-Phase heavy crude oil marketing plan to access our vast resource base.

THE ASSETS
Our midstream infrastructure provides us with flexibility. The ECHO pipeline delivers undiluted raw bitumen used in our Synbit and WCS crude oil blends.

Marketing

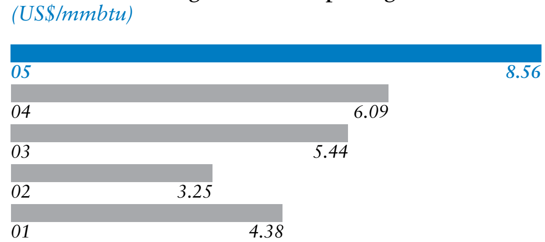
NATURAL GAS

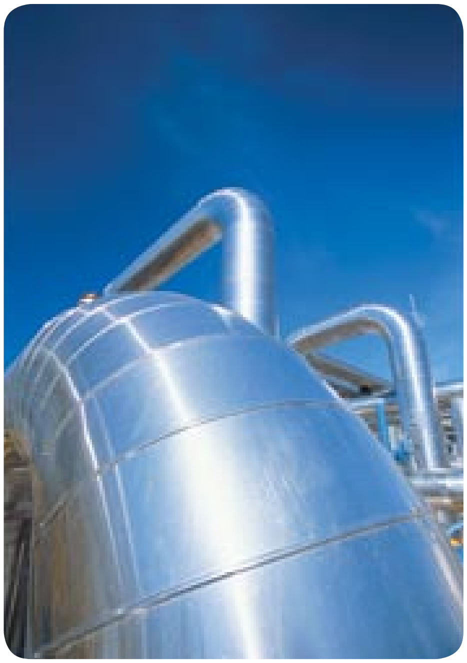
Canadian Natural's gas marketing objective is to maximize the realized price for its overall portfolio. Our strategy requires us to develop solid business relationships based on demonstrated performance and integrity and to work together with our customers to meet their needs. The Company markets primarily to large credit worthy utilities, industrial and commercial customers across North America. The current portfolio includes 20% of direct sales to various American customers, 69% sold directly into our domestic markets with the remaining 11% going to the Alberta based gas supply and market aggregators. Canadian Natural's portfolio is essentially driven by current market prices with over 98% of all sales fluctuating with the pricing index prevailing at the points of physical delivery of the gas. The marketing team monitors regulatory applications by the pipeline companies and participates as necessary to ensure an optimal outcome is achieved for all concerned parties.

Canadian Natural's realized wellhead price improved by 32% in 2005 to $8.57/mcf primarily in response to a very tight North American supply environment exacerbated by the devastating hurricanes Katrina and Rita impacting the US Gulf Coast in early Fall of 2005. The average annual prices for 2005 were up 41% on the NYMEX and 25% at the AECO hub with the basis differential at AECO widening by 63% in Canadian dollars over the 2004 average. As of early March 2006, the cumulative losses of gas production from the affected areas are estimated at 678 bcf with some 1.4 bcf/d of production still down. This extraordinary supply disruption resulted in very high gas prices reaching US$15/mmbtu in December 2005 and causing several industrial plants to curtail or temporarily shutdown their operations. However, this winter will also be characterized by the warmest month of January on record creating a very volatile pricing environment with the current NYMEX price at the US$7/mmbtu level. The gas storage positions are expected to close the withdrawal season at the end of March 2006 at levels not seen since 1991.

The drilling activity continued to be very high in 2005 with a record number of completions in Canada at 16,700 and the US at 27,000. However, the North American overall supply was essentially flat year over year with the increase in the electrical generation offset by the losses from the industrial sector. We expect the North American supplies to be challenged over the next several years even with the increased drilling for the tight gas in the Rockies and the promising CBM in Alberta. The timeframe for the production of gas from the McKenzie Delta and Alaska projects continue to be extended into the next decade given the economic and regulatory challenges. The large number of proposals to import liquefied natural gas in the North American grid has yet to translate into incremental quantities available to the end users with the 2005 import volumes remaining flat at 1.8 bcf/d. The forecast is for a modest increase of these volumes in 2006 as the competition for supplies intensifies with European and Asian markets.

NYMEX natural gas reference pricing
(US$/mmbtu)





The marketing team maximizes our wellhead price realizations by optimizing the logistics and creatively developing new markets for our heavy crude oil.

RÉAL M. CUSSON
Senior Vice-President, Marketing

Canadian Natural's natural gas production for 2006 is forecast to average between 1,450 – 1,515 mmcf/d and with the current 2006 pricing strips for NYMEX at US$7.95/mmbtu and AECO at C$7.22/GJ this would yield an overall wellhead price of C$7.12/mcf for our sales portfolio, using a US$0.88/C$1.00 exchange rate.

CRUDE OIL

Canadian Natural's crude oil marketing strategy is designed to unlock the value of our vast heavy oil reserves. The three major components of our strategy consist of blending various crude oil streams and diluents to better serve the needs of our refining customers, support and participate in the expansion of pipeline export capacity and to support and participate in projects adding incremental conversion capacity for bitumen and SCO.

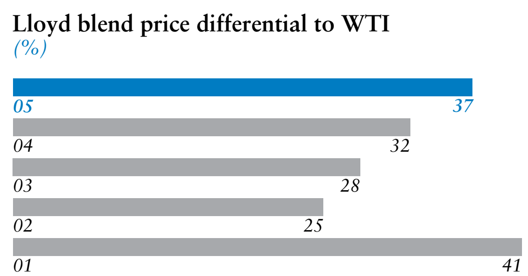
Canadian Natural's realized wellhead price improved by 23% in 2005 to $46.86/bbl mainly based on the strong worldwide demand for hydrocarbons and a constrained supply environment with practically no spare capacity from the producers and full utilization of worldwide refining assets.

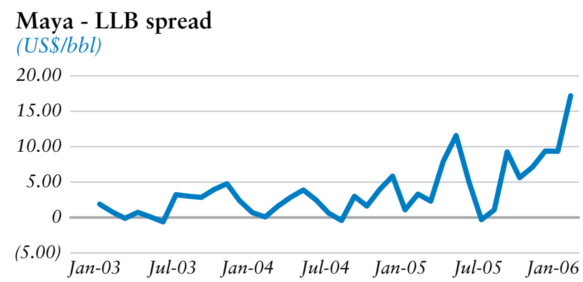
The benchmark price for WTI crude oil was up 37% in 2005 US$56.61/bbl and the Brent crude oil was higher than in 2004 by 42% to US$54.45/bbl. The price differential for the Lloyd Blend heavy crude oil widened by a significant 5% in 2005 to an average of 37% of the WTI price and the Canadian currency strengthened by 7% over the US dollar.

The demand continues to grow strongly in the Asian markets and moderately in the North American and European markets while the supplies are essentially at capacity. The worldwide reserves are generally abundant, however there are several economic, logistical, labour related, and geopolitical challenges to overcome to bring on additional production on a sustainable basis. The damage caused by the hurricanes in the US Gulf Coast and the operational problems encountered at several refineries in 2005 simply exacerbated an already tight balance for hydrocarbon products.

WTI crude oil reference pricing
(US$/bbl)

05	56.61
04	41.43
03	31.02
02	26.11
01	25.91





Canadian Natural continued to successfully implement its blending strategy in 2005 by contributing 55% of the total 255 mbbl/d of WCS stream in the fourth quarter. To further enhance our blending flexibility and economics, we have initiated a full evaluation for the importation of condensate or natural gasoline from various American facilities.

The logistical challenges are being addressed by industry and significant progress was achieved in 2005 with the approval of the Enbridge Southern Access Pipeline expansion which will add 394 mbbl/d to the greater Chicago market area by 2009 and the Terasen TMX 1 project to add a total of 75 mbbl/d to the West Coast by 2008. The TCPL Keystone project to add 400 mbbl/d to the Woodriver market area with further option to extend to Cushing has received sufficient commitments to proceed further. Two long haul pipeline projects are being developed to transport oil from Edmonton to the West Coast with access to the US refineries and the Asian markets. The Enbridge Gateway project is for 400 mbbl/d to Kitimat and the Terasen TMX project is for 625 mbbl/d split between Vancouver and Kitimat/Prince Rupert. We believe these two projects are at least five years away given the required market developments and regulatory requirements. We are confident that the industry will proceed with the necessary incremental pipeline export capacity on a timely basis to support the expected incremental production out of the WCSB and specifically from the oil sands projects.

The Corsicana pipeline is scheduled to ship heavy crude oil from Patoka, IL to Nederland, TX by late March 2006. Canadian Natural has committed 25 mbbl/d for five years on this pipeline that could eventually carry up to 80 mbbl/d to US Gulf Coast refineries. The Spearhead pipeline started shipping 80 mbbl/d of oil from Chicago, IL to Cushing, OK on March 2, 2006 and has the capacity to ship 125 mbbl/d. Both pipelines could be expanded further with market demands for Canadian crude oil.

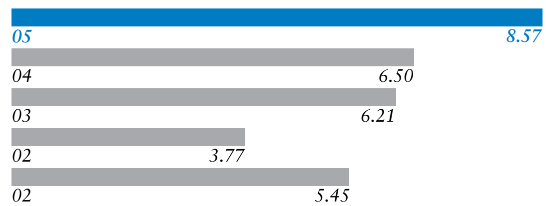
Canadian Natural continues to work with North American refiners to encourage them to add more conversion capacity to their facilities. The Company is also proceeding with a full evaluation of its second heavy crude oil upgrading facilities in addition to its Horizon Project. The full scope definition and the detailed evaluation of the upgrading technology to be used are currently underway at the selected engineering firms and we expect to complete this phase in early 2007. We intend to follow the same rigorous process employed for the Horizon Project. The initial concept is to upgrade the bitumen into a sweet SCO and to incorporate the synergistic benefits of heat integration between the upgrading process and the thermal bitumen production with the potential use of the gasification technology.

Canadian Natural's portfolio for 2006 is forecast to average between 335 mbbl/d and 373 mbbl/d and with the current 2006 pricing strips for WTI at US$64.42/bbl would yield an overall wellhead price of C$37.73/bbl, using a US$0.88/C$1.00 exchange rate.

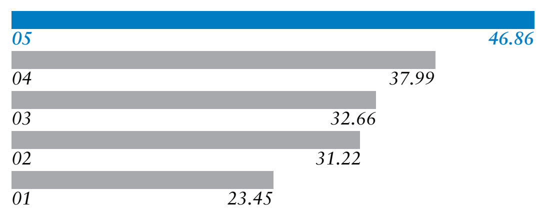
PRICE RISK MANAGEMENT

Canadian Natural utilizes hedging techniques to provide some assurance on price realizations and to protect cash flow generation capability in order to fund ongoing development programs. Generally, the downside pricing risks associated with various commodities are determined and, if deemed appropriate, financial derivatives are used to limit risk. Currency exposures are also monitored and may be hedged in conjunction with commodities.

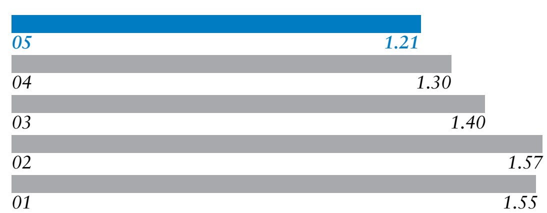
Company average natural gas selling price
(C$/mcf)



Company average crude oil and NGLs selling price
(C$/bbl)



Canada/US average exchange rate
(US$ in equivalent C$)



In conjunction with approval of the Horizon Project, our Board of Directors granted management the authority to hedge up to 75% of any commodity's expected production volumes for a forward 12-month period, up to 50% of the second 12-month period and up to 25% for the following 24-month period.

MIDSTREAM

Our midstream assets consist of the 100% owned and operated Echo pipeline, the 15% interest in the Cold Lake Pipeline system, the 62% interest in the operated Pelican Lake Pipeline and the 50% interest in the 84 megawatt co-generation unit located at our Primrose facility. The midstream assets allow us to control and optimize transportation costs for about 80% of our heavy crude oil production and generate additional revenues from third party volumes and the sale of surplus electricity.

Echo is the only pipeline delivering undiluted raw bitumen to the Hardisty terminals and plays an important role in our heavy crude oil blending and marketing strategy for WCS and other diluted bitumen blends.

We will be completing a lateral pipeline from its ECHO pipeline to our Morgan battery in the third quarter of 2006 at a cost of $6 million to increase the utilization rate from 86% in 2005 to 90% once completed.

The 2005 revenues from our Midstream assets increased by 16.6% to $77 million primarily from higher volumes on Echo and Pelican pipelines, increased revenues from our Nipisi terminal and higher sales of surplus electricity from our Primrose cogeneration facility into the Alberta provincial grid.

THE PEOPLE

Capital discipline is ingrained throughout all operating units. They are accountable for the capital they spend and the value they create.

THE PLAN

Maintain good access to capital markets while ensuring balance in our borrowing sources and the term of their maturities.

THE ASSETS

Backstopping our finances are assets capable of generating significant free cash flow, even in a lower priced environment.

Financial Plan

Canadian Natural has always viewed financial strength as integral to ongoing success. We have carefully developed our financial capacity to both profitably grow our conventional crude oil and natural gas business and to finance this growth as well as construction of our world class Horizon Oil Sands Project.

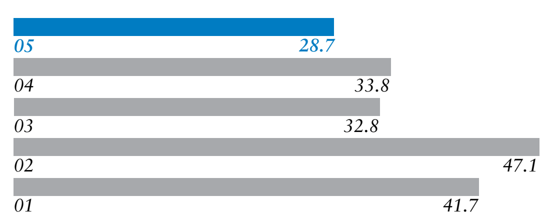
OUR FINANCIAL STRENGTHS ARE MANY AND INCLUDE:

- A diverse asset base both geographically and by product, most of which is located in G-7 countries with stable and secure economies. This, coupled with our exploitation approach to the business, reduces operational risk.
- Financial liquidity, including $3.4 billion of bank credit facilities, $3.3 billion of which were unutilized at December 31, 2005.
- A diversified production base with strong internally generated cash flows, supported by a proactive hedge program.
- Flexible capital expenditures program with a balance of solid production maintenance as well as short-, medium-, and long-term initiatives.
- A proactive, flexible approach to project development and financing strategies predicated upon our 5- and 10- year business plans.
- A strong balance sheet with a debt to book capitalization of 29% as at December 31, 2005.

In concert with the sanctioning of the Horizon Project and as more fully described in the Management's Discussion and Analysis, our risk management program was increased during 2005. In order to avoid financial stress should commodity prices fall during the period of 2005 through 2008 when we are constructing Phase 1 of the project, the increased assurance of future cash flow levels afforded by the risk management program, combined with the high degree of cost certainty acquired for construction costs, were critical to the sanctioning of Phase 1 of the Horizon Project.

As a strong investment grade borrower, we have many financial ratios to which we steward. For example, we target to maintain a debt to book capitalization of about 35% to 45%, depending upon where we are in the business cycle. Assuming a post 2006 US$35/bbl WTI price environment, we believe that our disciplined approach to balance sheet management will facilitate

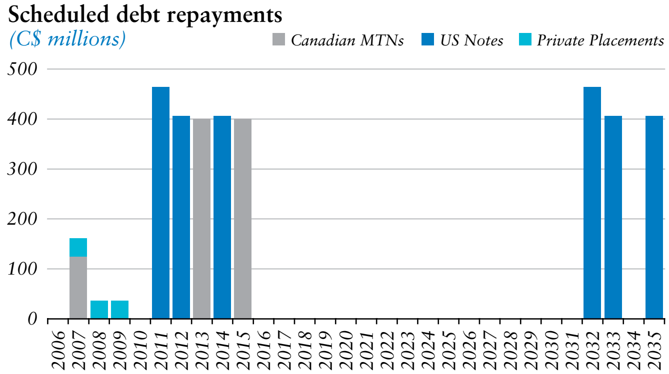
Debt to book capitalization
(%)

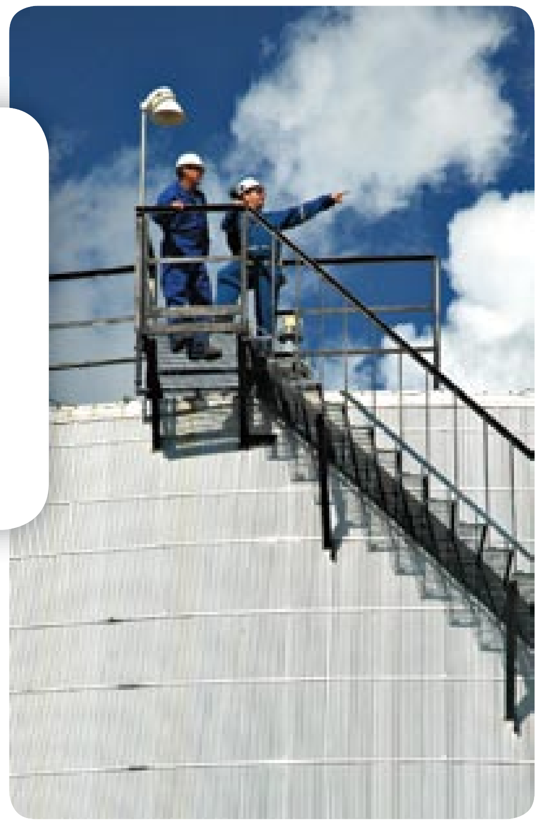


DOUGLAS A. PROLL
Chief Financial Officer
& Senior Vice-President,
Finance

RANDALL S. DAVIS
Vice-President,
Financial Accounting
& Controls

Scheduled debt repayments
(C$ millions)

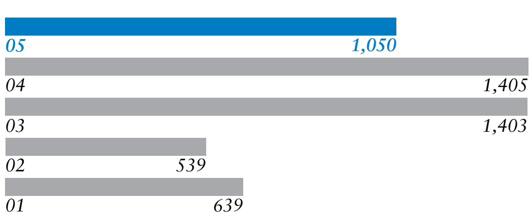




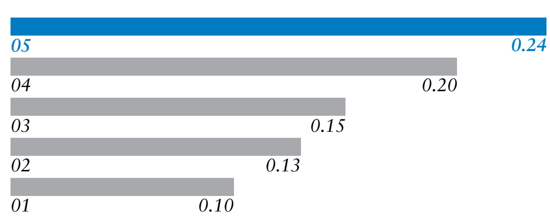
the delivery of our conventional growth plans as well as the construction of the Horizon Project and the Canadian Natural Upgrader. Under these plans we would expect to remain within our targeted range.

Having this excess financial capacity means that Canadian Natural does not have to compromise on its balanced strategies. Maintaining a strong balance sheet provides flexibility to our operations and the execution of our defined plan.

Net earnings
(C$ millions)



Dividends per common share
(C$/share)



Health & Safety, Environment and Community

OUR COMMITMENT TO RESPONSIBLE OPERATIONS

"Doing it right" is part of our mission statement and integral to the way we approach our business. We continue to conduct our operations with diligence to ensure we comply with all regulatory standards and guidelines, and with the discipline and proactive focus to achieve continuous improvement in our stewardship performance. Our people and contractors understand they are accountable on a daily basis to implement our vision for health and safety, environment and community.

HEALTH AND SAFETY PERFORMANCE: INCREASED AWARENESS, EFFECTIVE SYSTEMS AND CO-OPERATION

We believe the continual improvements in our health and safety performance can be attributed to enhanced safety awareness in our operations, continuous improvement of our safety management systems, and a high degree of co-operation with our contractors in meeting health and safety goals.

In our North American conventional operations, our total recordable injury frequency continued to decline in 2005 despite it being the most active in our history. Approximately 10 million more man hours were worked in 2005 than in 2004 with a reduction in the recordable injury frequency of 16%. Lost time injury and first aid injury frequencies have also continued to decrease during the past three years.

As part of our proactive approach, the number of facility, rig, construction and pipeline safety and compliance audits performed in our conventional operations increased by nearly 50% over the number conducted in 2004. This aggressive audit program continues in 2006. Internationally, we implemented the key elements of our Safety, Health and Environment ("SHE") Improvement Program, a key feature in our major accident hazard management strategy.

At the Horizon Project, our Health and Safety team has assembled an extensive operational group to provide medical, safety and security support to the more than 2,000 people now working on-site. At year-end, all safety frequency statistics for the Horizon Project were better or comparable to statistics benchmarked against the Construction Owners Association of Alberta (COAA) for comparable projects. By year-end, Horizon Project had surpassed more than 3 million exposure hours without a Lost Time Accident. As Horizon Project activities increase in 2006, there is ongoing development of the Safety Management System, site procedures, and safety training programs.

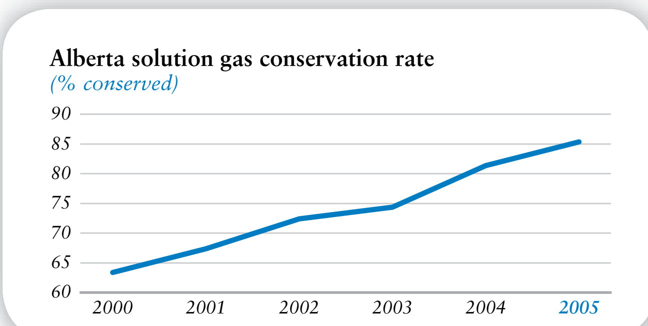
ENVIRONMENTAL INITIATIVES FOCUS ON CURRENT OPERATIONS AS WELL AS FUTURE DEVELOPMENTS

Canadian Natural continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently in an environmentally sound manner. Our environmental strategies target energy efficiency, air emissions management, water quality, reduced fresh water use, and the minimization of our landscape footprint. Training and due diligence for operators and contractors are key to the effectiveness of our environmental management programs and the prevention of incidents.

With a view to operational start-up of the Horizon Project in 2008, we are already addressing environmental aspects as diverse as the development of an audit/inspection package to encompass operations, the implementation of our wildlife corridor research program, and the construction of a fresh water lake to compensate for fish bearing streams lost to development.

In our conventional operations, our multi-year flaring and venting reduction strategy has significantly contributed to our air emission management programs. In 2005, Canadian Natural invested more than $15 million and completed more than 130 natural gas conservation projects with resulting recoveries in excess of 13 mmcf/d. In 2006, we plan to complete another 120 such natural gas conservation projects with a capital investment of $17 million.

Though Canadian Natural has significantly increased our heavy crude oil production, we have also been able to increase the percentage of solution gas conserved. In 2005, Canadian Natural continued to increase both the amount of solution gas that is collected and sold or utilized for lease fuel. Our solution gas conservation rate has increased from 63% in 2000 to 85% in 2005.



Our Greenhouse Gas (GHG) emission reduction strategy is based on emissions intensity. Our goal is to consistently reduce GHG emissions per unit of production. We systematically and continuously review opportunities for emissions reduction at our facilities, and we are developing and implementing strategies that include technological solutions and stakeholder input. Since 2002, our emissions intensity has been reduced 13% despite significant increases in activity and production.

At our primary heavy crude oil and in-situ oil sands operations our goal is to recycle produced water and supplement with brackish water, significantly reducing our fresh water use. At our Primrose operations we are now recycling about 95% of our produced water and have invested about $40 million in new brackish wells, pipelines and water treating capacity for our expanding operations.

At our international operations, 2005 was the fourth year in succession where we achieved a decrease in total operational oil in produced water. We again exceeded our target of less than 25 parts per million ("ppm") from our installations, well below statutory guidelines of 40 ppm.

BUILDING FUTURES TOGETHER WITH COMMUNITIES

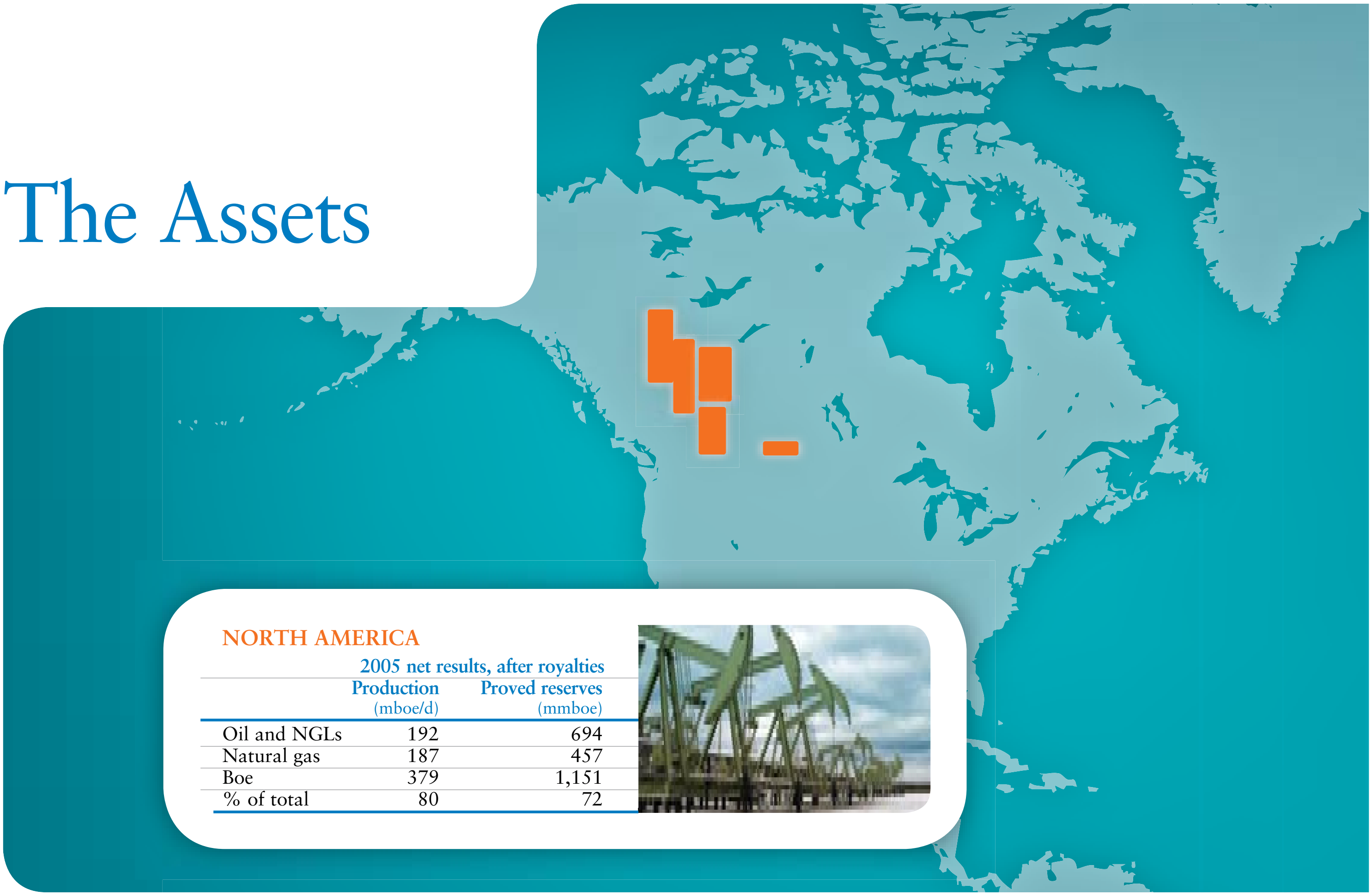
Canadian Natural continues to build and maintain co-operative working relationships with our stakeholders, and to support communities in their quality of life initiatives. We encourage and welcome stakeholder input into our plans and ongoing operations.

We are working collaboratively with many First Nation and Métis leaders near our operations. We continue to consult with First Nation and Métis communities related to reducing impacts on traditional lands and incorporating Traditional Environment Knowledge into our development and reclamation plans. Together, we have been identifying strategies and implementing action plans so communities can play a more direct role in the development of crude oil and natural gas resources. In 2005 we also increased financial and leadership support for Aboriginal education and training programs.

We continue to expand our Building Futures Scholarship Program which supports training to help meet the human resource needs for oil and natural gas field operations. Since 2002, we have awarded more than $400,000 in scholarships to more than 300 students living in 26 communities near our operations.

Our community investment programs contribute to the development of people and to the building of strong communities. We are proud to work with our communities in Western Canada, the UK and West Africa to provide financial and volunteer support for hundreds of projects that meet their vision for the future in education, wellness, arts, sports, and social programs. In our international operations, for example, we constructed a water tank tower and potable water network for the Adjue village in Côte d'Ivoire to help improve the lives and health of community members. In addition to the backing we provide to community programs and capital projects, our people throughout our operations in Western Canada have selected a variety of local community agencies that we support. Our corporate office matches each dollar contributed by our employees and contractors to these important community agencies.

The Assets



NORTH AMERICA

	2005 net results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Oil and NGLs	192	694
Natural gas	187	457
Boe	379	1,151
% of total	80	72

DEFINED STRATEGY TO EXPLOIT A WORLD CLASS ASSET PORTFOLIO

Our exploitation based development philosophy has proven through the business cycle to minimize exploration risks and maintain low operating and capital costs. This disciplined approach is applied rigorously throughout Canadian Natural's worldwide operations. It includes:

- Maintaining a large inventory of undeveloped land in each core region enabling us to continually high-grade prospects and to optimally plan future drilling programs.
- Dominating the land base and controlling the infrastructure in regions in which we operate. We maintain high working interests and operate the vast majority of our assets allowing us to steward to our plans and control our costs.
- Progressively developing lands as extensions from our existing infrastructure, thereby minimizing infrastructure costs.
- Evaluating and testing new techniques to maximize resource recovery.
- Maximizing our facility throughput, allowing us to reduce per-unit production costs. Whether it is compressor utilization in Canadian natural gas operations, water and sand disposal in heavy crude oil operations or FPSO capacity utilization internationally, we aggressively seek opportunities to leverage capabilities and reduce per-unit costs.

NORTH AMERICAN NATURAL GAS

North American natural gas is Canadian Natural's single largest product, representing 43% of our equivalent production volumes and 46% of sales revenues in 2005. During 2005, average production volumes increased by 86 mmcf/d or 6%, reflecting both a strong drilling and asset development program and the full year impact of 2004 property acquisitions. Production is concentrated in four of our North American core regions: Northeast British Columbia, Northwest Alberta, the Northern Plains and the Southern Plains. We have a defined five year development plan for each of these regions that results in 5% per annum production growth.

NORTH AMERICAN CRUDE OIL AND NGLS

Canadian Natural is one of Canada's largest producers of crude oil and NGLs with an extensive developed and undeveloped light and heavy crude oil asset base augmented by NGLs which are produced in conjunction with natural gas. During 2005, average production volumes increased by 7%, reflecting our successful drilling and development programs. Our heavy crude oil production is concentrated in the Northern Plains core region with light crude oil being produced in all five of our core regions.

Our exploitation based strategy capitalizes on our dominance in our core regions reducing both capital and operating costs. Our expertise in recovery techniques allows us to continually focus on maximizing crude oil recovery from both mature and new crude oil pools.

LYLE G. STEVENS
Senior Vice-President,
Exploitation

JEFF W. WILSON
Senior Vice-President,
Exploration

INTERNATIONAL

	2005 net results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Oil and NGLs	91	424
Natural gas	4	17
Boe	95	441
% of total	20	28

OIL SANDS MINING

	2005 proved reserves	
	Gross (mmbbl)	Net (mmbbl)
Bitumen	2,235	1,848
SCO*	1,833	1,626

* SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

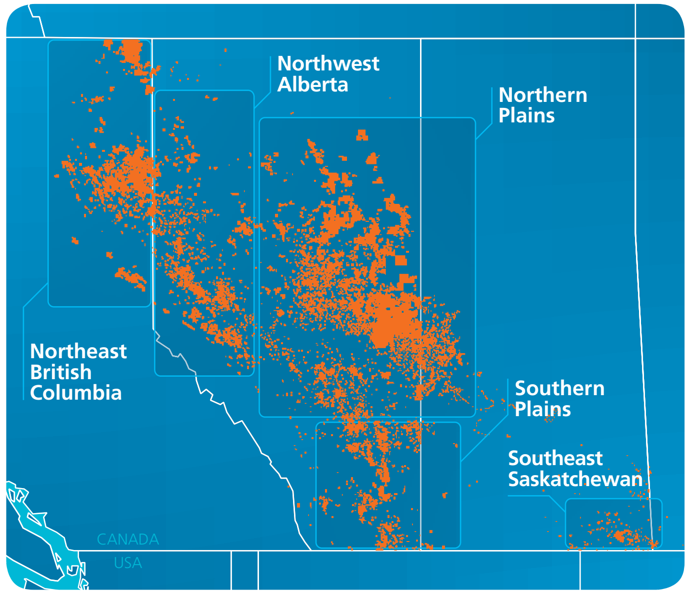
INTERNATIONAL

Our international operations provide a vehicle for continued light crude oil production growth. A disciplined and focused approach is essential to successful value creation in the international arena, therefore, we limit our exposure to those basins where we see the greatest opportunities and we can best lever our business strategies. We capitalize on our core competency of mature basin exploitation in the North Sea where the business parallels that of the WCSB in many ways. Offshore West Africa provides development opportunities and significant exploration upside, capitalizes on strong government relationships developed over the past few years and leverages the technical/operational expertise in the North Sea. In both basins, we operate in areas where we dominate the land base and have the infrastructure to support our operations.

OIL SANDS MINING

We hold extensive leases in the Athabasca region north of Fort McMurray that are amenable to the open pit mining of bitumen. These resources will be upgraded on site to a light sweet SCO and may be produced for decades to come without production declines normally associated with crude oil production. Our Horizon Oil Sands Project represents a phased development accessing up to 6 billion barrels of bitumen resource potential. Today we are in construction of the 110,000 bbl/d Phase 1 with first oil expected in the second half of 2008. Subsequent phases are planned with total potential production from the leases of approximately 500,000 bbl/d by 2017.

North American Natural Gas



NORTHEAST BRITISH COLUMBIA

THE ASSET AND OUR PLAN

Our experience in Northeast British Columbia, our large undeveloped land base of 2.0 million acres and 6,000 kilometers of pipelines affords us a significant competitive advantage in this highly prospective region. We further break this region down into three distinct geological play types:

1. Most northerly is the Helmet area where we employ horizontal wells to exploit the low-risk, regionally extensive, natural gas charged Jean Marie carbonate formation.

2. In the Fort St. John area, natural gas is produced from an array of carbonate and sandstone reservoirs ranging from the Notikewin at 2,000 ft to the Slave Point at 15,000 ft.

3. Most southerly is the Foothills region where we target deeper Mississippian and Triassic age reservoirs in this highly deformed structural area.

2005 ACTIVITY

At Helmet, the Company drilled 46 net wells with an 85% success rate adding incremental production of 20 mmcf/d. In total, 228 net wells were drilled with a 88% success rate, including 57 net Notikewin natural gas wells. Since this shallow regional play was identified in late 2003, the Company has drilled 156 net wells on this trend with a success rate of 89%.

We apportion a modest capital budget each year to explore for Slave Point reefs, targeting reservoirs with 5 to 30 bcf of recoverable natural gas. In 2005, 2.4 net Slave Point wells were drilled resulting in 1.4 net successful wells. In the Foothills of NE British Columbia and NW Alberta we are successfully increasing our exploration and development activity as we target deep Cretaceous reservoirs. Well costs are higher and pipeline infrastructure is less developed but rates and reserves are commensurately much higher. During 2005, 10 net wells targeting deep reservoirs were drilled that will add an estimated 35 mmcf/d of incremental production.

WHAT TO EXPECT IN 2006 AND BEYOND

The 2006 drilling program is well defined with more than 260 wells planned, including 66 Notikewin wells and 30 horizontal wells at Helmet. On the exploration front, four deep natural gas wells are planned targeting the Slave Point formation.

Our project inventory is deep with more than 1,500 well locations planned over the next five years. Our large undeveloped land base and our superior inventory of drilling prospects in the prolific relatively undeveloped basin of NE British Columbia creates one of the key drivers for our future natural gas growth. We project resource potential of 1.2 tcf in our 5-year forecast for this core region.

NORTHWEST ALBERTA

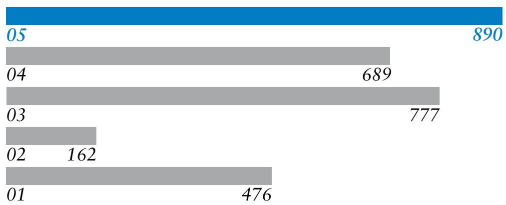
THE ASSET AND OUR PLAN

This region contains exceptional exploration and exploitation opportunities in combination with our extensive, owned and operated infrastructure. We produce liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 2,000 to 15,000 feet. We leverage our existing developments to exploit existing pools while continuing to develop unconventional and tight gas plays. Landholdings in the region exceed 1.5 million undeveloped acres and we own and operate more than 26 facilities and 1,800 miles of pipelines to support our operations.

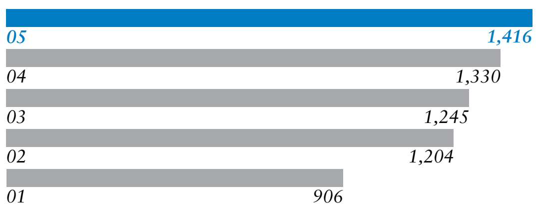
2005 ACTIVITY

In this region we drilled a total of 166 net natural gas wells, a 17 net well increase from 2004. We continued our low-risk Cardium sand development, drilling 76 net wells with a remarkable 99% success rate. The focus of our excellent technical team on this complex tight sand reservoir has resulted in a previously costly and risky play becoming a low-risk exploitation development. We are now leveraging the Cardium play in this region to economically access deeper horizons.

Successful natural gas wells drilled
(net wells)



North American natural gas production, before royalties
(mmcf/d)



We believe that our asset base is capable of delivering continued growth over the next 5 years.

In the northern portion of this core area we continued to expand our multi-zone drilling program and also extended the shallow Notikewin play first developed in Northeast British Columbia.

WHAT TO EXPECT IN 2006 AND BEYOND

The 2006 drilling program includes almost 150 net wells, with large programs for the Cardium, 57 net wells, and the Notikewin, 13 net wells. We have identified more than 950 locations to be drilled over the next five years in this core area. Through delineation drilling, technical analysis and land acquisitions we have secured a competitive advantage in the deep basin in this region and we foresee significant potential from this play type. Our expertise in the region coupled with our extensive undeveloped land base creates a strong natural gas growth profile and the second core area that will drive our corporate natural gas growth. Here we target new natural gas resource potential of 1.3 tcf over the next five years.

NORTHERN PLAINS

THE ASSET AND OUR PLAN

Natural gas in the Northern Plains core region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon coal bed methane (“CBM”). This is generally considered a mature operating region however through ongoing focused exploitation we continue to find excellent prospects for both development drilling and secondary zone recompletions. Our strategy in this region is to target low-risk exploration and development opportunities on our extensive land base, continue expansion of our commercial CBM project, examine synergistic property acquisitions opportunities, and minimize operating costs through high utilization of facilities and operations discipline.

2005 ACTIVITY

During 2005, 238 net wells targeting natural gas were drilled in the region with a 84% success rate. CBM development drilling continued to grow with the drilling of 42 net wells.

WHAT TO EXPECT IN 2006 AND BEYOND

The 2006 drilling program includes 353 net natural gas wells and recompletion of 299 net wells. Over the next five years we have identified over 1,700 net natural gas locations, including 510 net Horseshoe Canyon CBM locations and more than 800 recompletion opportunities.

SOUTHERN PLAINS

THE ASSET AND OUR PLAN

Natural gas in the Southern Plains core region is produced from shallow, low-risk wells drilled at high densities, conventional multi-zone and additional CBM prospects. We’ve operated in this core region for 10 years and expect to grow production by an average of 4% per annum for the next 5 years. We continue to regionally expand the prospective area for shallow gas resulting in new infill drilling opportunities and new shallow plays in undeveloped areas. We have maximized our returns on shallow gas and CBM by utilizing our area dominance and existing infrastructure to add low-cost volumes.

2005 ACTIVITY

The 2005 drilling program, at 342 net wells, represented a 47% increase over 2004 activity when capital was redeployed towards property acquisitions. This 2005 program included 209 net shallow natural gas wells, 58 net CBM wells and 75 net other natural gas wells.

WHAT TO EXPECT IN 2006 AND BEYOND

The 2006 drilling program is comprised of more than 375 net wells, almost 250 of which are targeting low-risk, shallow natural gas. 60 net Horseshoe Canyon CBM wells are planned as the Company continues to expand both its expertise and its commercial CBM operations. Our five year drilling inventory totals more than 1,550 net natural gas wells, including over 1,070 shallow locations and over 170 net Horseshoe Canyon CBM wells. With the addition of new shallow gas prospects and continued Horseshoe Canyon CBM development we are forecasting modest production growth in the Southern Plains over the next five years.

North American Crude Oil

LIGHT CRUDE OIL AND NGLS

THE ASSET AND OUR PLAN

We produce light crude oil and NGLs in all of the Company's western Canadian core regions. In North America, our light oil assets are largely developed; however, we continue to grow light oil production through a strategy of new waterflood implementation, existing waterflood optimization, development drilling, new pool discoveries and acquisitions. The vast majority of the Company's light pools are produced under waterflood resulting in high recovery factors and low production decline rates.

2005 ACTIVITY

In 2005, Canadian Natural's light crude oil drilling and development programs pursued four initiatives:

- Low risk, infill drilling in crude oil pools located in the Northern Plains, Northwest Alberta and the Southeast Saskatchewan core regions;
- Waterflood optimization programs in all our core regions. We have a strong technical team that is dedicated solely to waterflood optimization through detailed reservoir characterization, analysis of pattern performance, improved well operating practices and improved fluid processing at our facilities;
- New pool exploration and pool extensions in Northwest Alberta and Northeast British Columbia where 1,000 bbl/d of new production was added. Future development potential was also identified; and,
- Pilot testing of polymer flooding to improve oil recovery in a mature waterflood.

WHAT TO EXPECT IN 2006 AND BEYOND

For 2006, Canadian Natural will continue to focus on waterflood and tertiary recovery opportunities. Our 2005 drilling program has identified significant new development potential in the Fireweed area of Northeast British Columbia, the Worsley area of Northwest Alberta and the Pierson pool in Southeast Saskatchewan. More than 120 net wells are planned for our 2006 light crude oil drilling program making it the largest light crude oil program in the Company's history.

Canadian Natural will focus on waterflood enhancements to add incremental light crude oil reserves. We estimate that just a 1% improvement in recovery factor could yield an incremental 42 million barrels of reserves. In addition to the enhanced crude oil recovery initiatives our defined plan includes over 400 new well locations to be drilled over the next five years.

PELICAN LAKE CRUDE OIL

THE ASSET AND OUR PLAN

This massive, shallow crude oil pool in our Northern Plains core region is estimated to contain up to 3 billion barrels of OOIP and continues to provide excellent opportunities for production and reserves growth. We developed this pool exclusively with horizontal wells to minimize the environmental impact, reduce development costs and provide greater well productivity. We own and operate three centralized treating facilities in the area. Although priced similarly to heavy crude oil, our Pelican Lake crude oil production yields netbacks typical of medium crude oil due to our ability to maintain low operating costs.

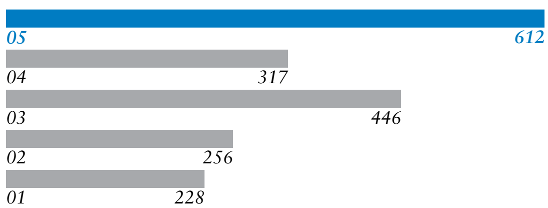
2005 ACTIVITY

At Pelican Lake 2005 proved to be very successful year:

- We continued to extend the developable area of the existing pool and drilled 52 net primary horizontal wells;
- 8 net stratigraphic wells were drilled to identify further pool extensions and other new pools in the area;
- We continued to expand the commercial waterflood project and have now converted 11% of our field to waterflood. A total of 25 sections are under waterflood with 64 net production wells and 72 net injection wells; and,
- We initiated a five well pilot test to determine the viability of polymer flooding with the goal of enhancing productivity and increasing oil recovery. Initial results are promising and lead to a commercial scale installation in 2006.

Application of EOR techniques to the 3 billion barrels of OOIP, combined with new drilling locations will continue to ramp Pelican Lake production levels.

Successful crude oil wells drilled
(net wells)



The waterflood, primary production drilling and continued optimization has reversed production declines in the field resulting in a 10 mbbl/d or 57% production increase from 2004.

WHAT TO EXPECT IN 2006 AND BEYOND

The 2006 program will see Canadian Natural drilling 126 net horizontal wells for primary production and 14 additional net stratigraphic wells to delineate pool extensions. Expansion of the Pelican Lake waterflood remains a priority and we plan to complete the conversion of 7 sections to waterflood. This will entail drilling 24 net horizontal infill production wells and converting 10 net producing wells into water injection wells. Secondary recovery processes are expected to double primary recovery factors on approximately 45 to 55% of the field.

Beyond waterflood implementation, we will continue to evaluate the use of polymer at our pilot test to enhance waterflood recovery. While it is too early to judge the technical and economic success of this enhanced recovery process, polymer flood could yield incremental recoveries of 15% over primary production. This could amount to 130 mmbbl of incremental recovery at Pelican Lake.

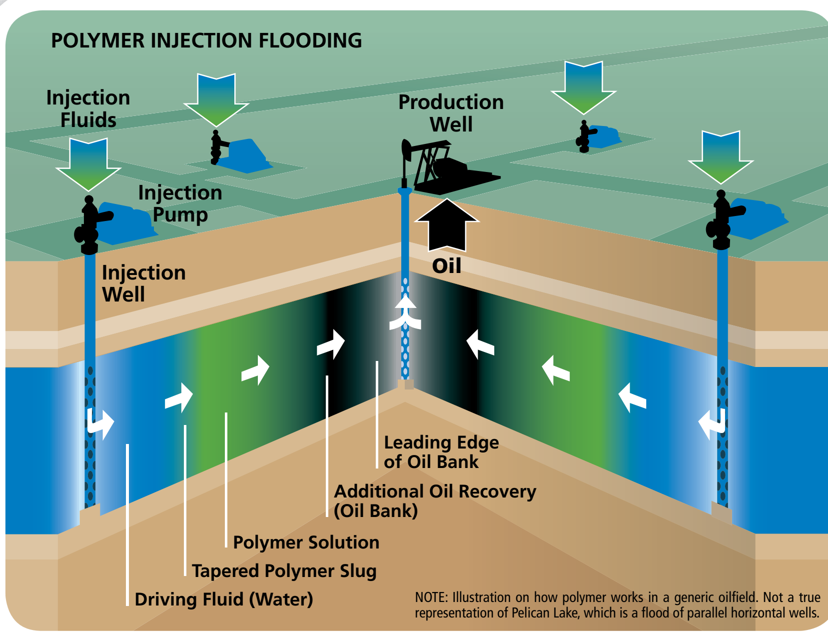
We currently expect that with our EOR projects combined with over 600 net well locations in our five year plan will continue to increase production over the next several years.

— CASE STUDY —
PELICAN LAKE

Pelican Lake is a large, shallow oil pool in Canadian Natural's Northern Plains core region estimated to contain up to 3 billion barrels of OOIP and is exclusively developed with horizontal wells. Optimization of the Field continues on several fronts as follows:

- We now drill wells with both single and multiple leg "tuning fork" wells efficiently draining more of the reservoir from each well. Our expected well inventory remains strong over the next five year period;
- Application of waterflood technology to a portion of the Field could increase recovery factors by a further 7.5% from the base expected recovery of about 5%;
- Application of Polymer flood (see figure) could increase recovery factors by 15% throughout the majority of the Field. Our initial pilot test for this flood commenced in early 2005 with preliminary results expected in 2006.

As a result of these initiatives, Pelican Lake production increased 57% during the year, reversing 3 years of production declines. Continued growth is expected in production volumes for the next five years, once again making Pelican Lake a growth story.



North American Crude Oil (continued)

PRIMARY HEAVY CRUDE OIL

THE ASSET AND OUR PLAN

Canadian Natural's historic growth in primary heavy crude oil production has been achieved through drilling as well as strategic, synergistic acquisitions. Heavy crude oil is produced using primary production mechanisms from shallow, low-risk, multi-zone wells. This leads to low finding and development costs, exceptional drilling success rates and many subsequent recompletion opportunities. The region is also natural gas prone and development drilling can lead to both natural gas and heavy crude oil discoveries. With over 1.6 million acres of undeveloped land and 200,000 acres of developed land, we dominate production and operations within the Bonnyville/Lloydminster primary producing area of our Northern Plains core region. This dominance allows us to minimize capital by conducting large scale drilling and development programs. We also minimize and control our production costs through owning and operating central treating facilities, maximizing their utilization and using our size to achieve economies of scale. Finally, ownership of the ECHO crude oil sales pipeline reduces our transportation costs and allows us to be the only producer capable of delivering undiluted heavy crude oil into our blending facilities at Hardisty, Alberta.

2005 ACTIVITY

During 2005 we drilled 360 heavy crude oil net wells, a 180 net well increase from 2004. Our ongoing program of recompletions continues to add low-cost volumes and in 2005 483 net wells were recompleted to secondary zones.

In our efforts to improve crude oil recovery beyond primary we initiated a heavy crude oil waterflood at our Lonerock Field and are field testing an experimental solvent injection scheme at Lindbergh.

WHAT TO EXPECT IN 2006

For 2006, 344 locations are forecast to be drilled and a further 340 net wells will be recompleted. Our defined growth plan forecasts that over 1,675 net well locations will be drilled during the next five years, keeping production relatively flat. As new markets are created for heavy crude oil we have the capability of ramping up this drilling effort and increasing production, however, we will not proceed until we are assured of this new demand. We will continue to pursue the development of applicable technologies to further improve oil recovery and are currently conducting research in both the field and the labratory. We estimate our developed lands to contain 7 billion to 10 billion barrels of OOIP; a modest 1% increase in recovery would equate to over 70 million barrels of incremental recoverable crude oil.

THERMAL (IN-SITU) HEAVY CRUDE OIL

THE ASSET AND OUR PLAN

Canadian Natural has some of the best thermal oil sands assets in Canada. In the Cold Lake region we have our commercial Cyclic Steam Stimulation (CSS) project whose production makes us the second largest thermal crude oil producer in Canada. In the immediate region we also have the undeveloped Primrose East lease which will provide for future growth using the same proven recovery process. In the Athabasca region we have more than 200,000 undeveloped acres of land suitable for thermal recovery processes. These assets coupled with the proposed Canadian Natural upgrader initiative would provide both short and long term growth for the Company. Our technical expertise, our asset base and years of experience operating and constructing thermal projects has placed Canadian Natural as an industry leader in thermal in-situ oil recovery.

2005 ACTIVITY

Our primary 2005 focus was the construction and start-up of the Primrose North expansion project. This project consists of a satellite steam generation plant and, 4 new well pads with 96 net horizontal wells that are pipeline connected to our central Wolf Lake processing plant. The expansion project was completed on budget and on schedule allowing for steam injection in Q4 2005 and production in January 2006.

As a result of continued development and optimization at our Primrose South project, our thermal oil production reached record levels, over 53 mbbl/d, which was a 22% increase over 2004.

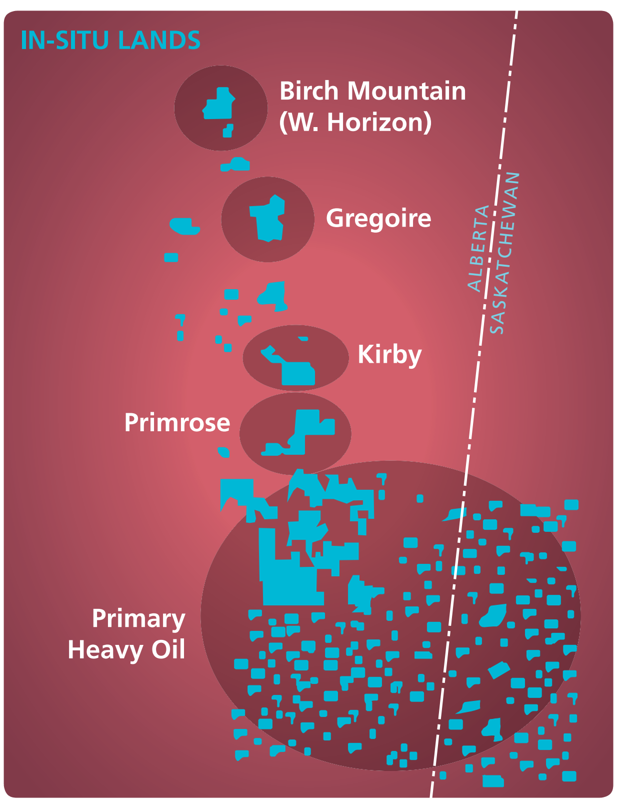
North American crude oil and NGLs production
(mbbl/d)

We are the second largest producer of crude oil recovered by thermal processes in Canada.

WHAT TO EXPECT IN 2006 AND BEYOND

For 2006, production from the Primrose North expansion project will reach its design capacity of 30 mbbl/d by the start of Q4. In 2006, we plan to drill an additional 75 net horizontal wells at Primrose as part of the ongoing project. As part of our long term thermal project expansion plans we will also drill more than 220 net stratigraphic wells to further define our leases at Primrose East, Kirby, Birch Mountain and Gregoire Lake. We will also continue to delineate further reservoir at Primrose South to maximize both resource recovery and the infrastructure utilization.

Mid-term growth will come from the commercial development at Primrose East where production is expected in 2009. The regulatory application for this project was submitted in January, 2006. Beyond 2009 we see the potential to add an incremental 240 mbbl/d of thermal in-situ production from our Athabasca oil sands leases at Kirby, Birch Mountain East, and Gregoire Lake. This new bitumen production will serve as feedstock for both the proposed Canadian Natural upgrader and the Horizon upgrader.



— CASE STUDY —
CANADIAN NATURAL UPGRADER

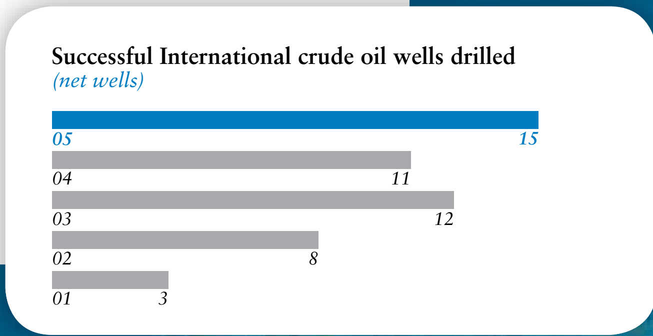
We are the second largest producer of crude oil recovered by thermal processes in Canada with 2005 combined average daily production of 53 mbbl/d from our three in-situ developments. Beyond this, we a vast heavy crude oil resource base capable of generating significant returns for our shareholders.

In order to capitalize on this opportunity we are proposing to build a heavy crude oil upgrader in Alberta which would convert this feedstock into a light sweet synthetic crude oil. This would significantly reduce the marketing risk of the production while increasing the expected realizations from its sale. It helps facilitate the development of these vast resources in a disciplined and stepwise manner.

During 2006 we will expend $30 million on a Scoping Study to determine the preferred location, technology, capital cost and crude oil output quality. We will also examine the use of gasification technologies to further control production expense. Resulting recommendations for the Upgrader will be tabled in 2007.

Following a disciplined emphasis on front end engineering we expect construction to commence in 2009 and first production in 2012. Preliminary capacity estimates are for 125 mbbl/d of SCO, expandable to 175 mbbl/d by 2015.

The proposed Canadian Natural Upgrader, by increasing average realizations and netbacks while expanding markets for our heavy crude oil will generate significant shareholder value for years to come.



We operate approximately 99% of our production with an average ownership interest of 80%. Operations are currently run from four hubs. By maintaining control of these assets we have been able to control the capital allocation and pace of our exploitation plans for the properties.

International

UNITED KINGDOM PORTION OF THE NORTH SEA

THE ASSET AND OUR PLAN

Our achievements are a result of the successful utilization of our mature basin exploitation expertise. The first stage is based upon optimizing existing facilities and waterfloods. We infill drill, recomplete, and workover wells and optimize waterfloods to increase production, lower costs and extend field life. The second stage incorporates more near pool development and exploration in order to maximize utilization of common facilities and ultimately extend all fields' economic lives. In 2006 and beyond, increasing emphasis on this type of work will be made.

We believe that the current environment within the North Sea is similar to that of the WCSB in the early 1990s. The basin is mature and many of the major operators are reducing activity levels or looking at divestiture of properties. Exploitation oriented companies like Canadian Natural are proactively pursuing such opportunities.

2005 ACTIVITY

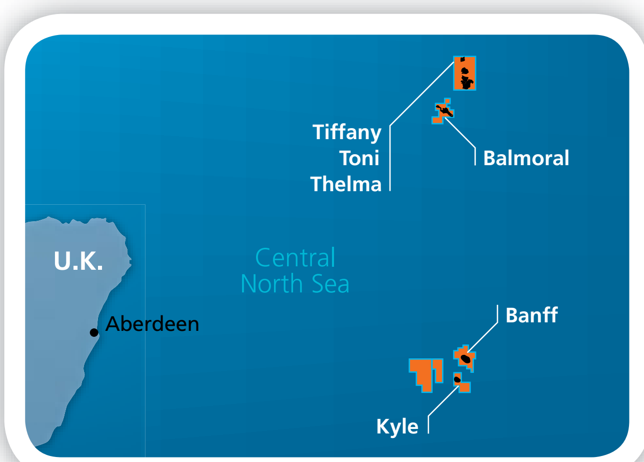
During 2005 we drilled 13.2 net wells and 0.9 service and injection wells, effectively offsetting production declines. At the Murchison Hub, production from the satellite pool Playfair continued, however third party natural gas export restrictions resulted in some curtailments of crude oil production. At the Ninian Hub, work progressed on the Columba Terrace and Lyell Field developments with engineering of subsea raw seawater injection facilities.

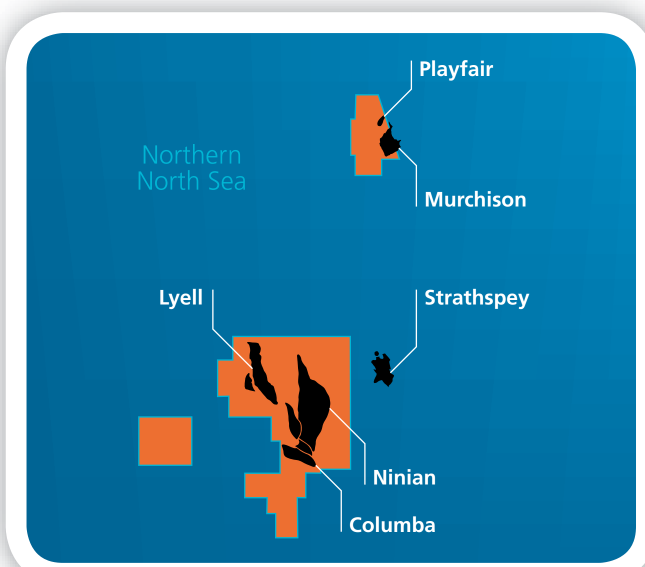
In the Central North Sea, production from at the Banff/Kyle Hub was consolidated into one FPSO, reducing operating costs and extending the economic life of both fields. The natural gas reinjection plan at Banff resulted in lower natural gas production volumes when compared with 2004, but should ultimately increase recoverability of crude oil from the reservoir. Refurbishment of the Tiffany Platform drilling rig was completed and a third party well was drilled and tariff income agreement was completed.

WHAT TO EXPECT IN 2006 AND BEYOND

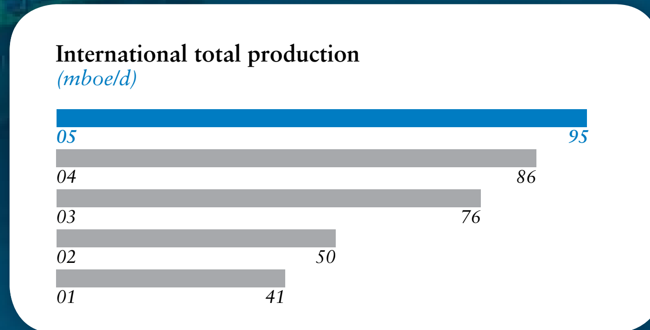
During 2006, 15 net wells are expected to be drilled, including 3 injector wells. At Murchison and Ninian Hubs we will increase water injection and processing throughput. At the Lyell Field, 4 new wells with artificial lift and an aggressive waterflood are part of the longer term plan to add approximately 20 mbbl/d of new plateau production in 2008.

With our current exploitation portfolio we expect to maintain or slightly grow current production levels over the next 3-4 years, but we continue to look for accretive acquisitions with exploitation upside for growth.





ALLEN M. KNIGHT
Senior Vice-President,
International &
Corporate Development



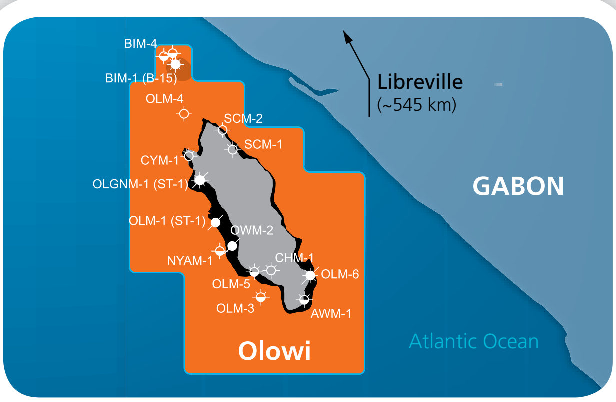
OFFSHORE WEST AFRICA
THE ASSET AND OUR PLAN

Canadian Natural has three exploration Blocks comprising approximately 274 thousand net undeveloped acres of land located offshore Côte d'Ivoire. We are currently continuing the development of three proved properties East Espoir, West Espoir and Baobab. East Espoir and Baobab are in production with further drilling continuing, whilst West Espoir will commence development drilling in Q2 2006.

2005 ACTIVITY

In Côte d'Ivoire in 2005 we drilled an additional two new net in-fill wells at East Espoir, tapping undeveloped portions of the pool and increasing production by 5 mbbl/d. Also during the year, first oil at our Baobab medium crude oil development was achieved on-budget in August 2005 with only 4.5 years elapsed from first discovery to first oil – an excellent cycle time for our first deepwater development. Our West Espoir development also continued on time and on budget with first oil expected in the second half of 2006. During the year the well head tower was installed on location and the drilling conductors were driven to depth.

In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon. The permit comprises a 90% interest in the production sharing agreement for the Block containing the Olowi Field, located 20 kilometers offshore and in 30 meters of water. Olowi has been delineated by the drilling of 15 wells by the previous owner and potentially contains as much as 500 million barrels of 34° API light crude OOIP.

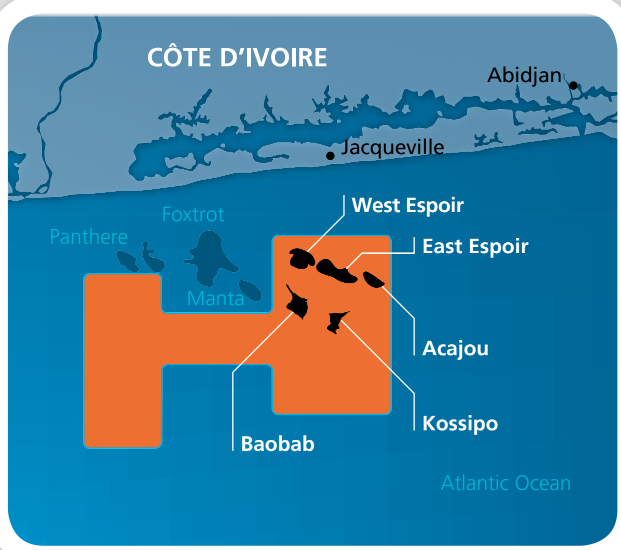


WHAT TO EXPECT IN 2006 AND BEYOND

For 2006, two more producer wells will be drilled at East Espoir and 3 wells at Baobab, essentially completing initial development. West Espoir is scheduled for first oil during the second half of 2006 following completion of production infrastructure and drilling of the first of 3 producer wells. Essentially, we will have grown our production in Côte d'Ivoire from no production at the start of 2002 to about 60,000 boe/d through these three developments – all at highly attractive economics. Beyond current developments, the nearby Acajou Field will eventually be tied back to the East Espoir as space becomes available in these facilities. Again, we leverage existing facilities to maximize recovery of economic reserves.

The Olowi development plan, comprising an FPSO and four drilling towers was filed with the Gabon Government in late 2005 and was approved for execution in early 2006. Following engineering design and request for tenders, the development will commence in late 2006 with first production targeted for late 2008 and a plateau production rate of 20 mbbl/d.

We plan to leverage our reputation and experience in the region to capture additional exploration and exploitation opportunities within this core region.



THE PEOPLE

We have assembled a world-class team of oil sands mining and project management experts.

THE PLAN

Our disciplined approach is based upon a heavy emphasis on front end design and engineering.

THE ASSETS

We estimate our leases to contain up to 16 billion barrels of bitumen resource potential with up to 6 billion of that amenable to open pit mining.

Horizon Project

HORIZON
THE ASSET AND OUR PLAN

Canadian Natural owns 115,796 acres in the Athabasca Oil Sands area of Northern Alberta, about 70 km north of Fort McMurray. The Horizon Oil Sands Project includes a surface oil sands mining and bitumen extraction plant coupled with on-site bitumen upgrading and associated infrastructure to produce a 34º API synthetic crude oil.

The project is designed as a phased development. First production of 110 mbbl/d of SCO from Phase 1 construction is targeted to commence in the second half of 2008. Production is targeted to increase to 155 mbbl/d following completion of Phase 2 in 2010. Finally, production levels of 232 mbbl/d are targeted for 2012, following completion of Phase 3 construction. The Company is currently evaluating the opportunity to combine Phase 2 and 3 for a joint operational date of 2011. The project receives the benefits of typical mine operations where production is limited only by the facilities and infrastructure – while capturing the generous revenues of oil production with no declines. Sustaining capital will average about $1.22/bbl once the plant is up and running – resulting in significant free cash flow.

Construction capital costs for Phase 1 of the Horizon Project are estimated at $6.8 billion, including a contingency fund of $700 million, with $1.3 billion spent in 2005, $2.6 billion forecast to be incurred in 2006 and $2.9 billion forecast to be incurred in 2007 and 2008 combined. Total targeted capital costs for all three phases of the development are projected to be $10.8 billion in a US$45/bbl WTI world.

THE HORIZON ADVANTAGE

The technology at the Horizon Project is based on that currently in use at existing plants, effectively mitigating technology risk in Phase 1. That being said, our plant has been configured in a manner to maximize benefits from the technologies. For example, the Horizon Project will have a very high level of heat sharing and integration between the facilities, reducing both natural gas consumption and greenhouse gas emission levels.

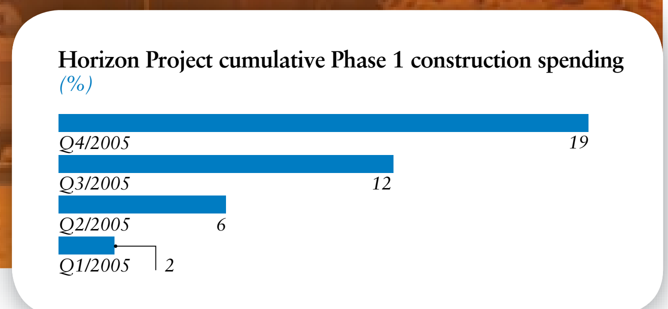
The geological risk associated with the project is very low. On this lease, over 16 stratigraphic net wells per section have been drilled to identify overburden levels, and test the ore composition and quality. The result is a well designed mine plan that has been optimized to support the bitumen extraction and processing.

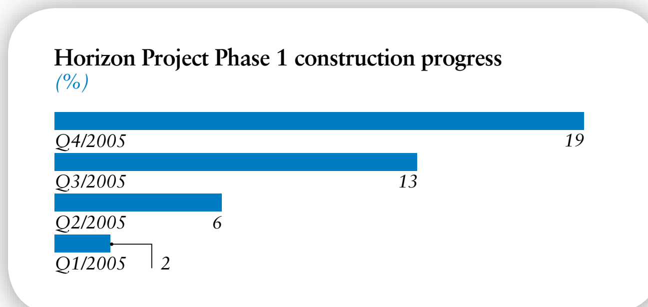
To ensure efficient construction, we have implemented an "80% rule", with about 80% of the engineering effort required completion prior to major facility construction. This will allow us to ensure materials are available prior to construction and minimize rework. In addition we believe that our execution and labour strategy combined with the fly-in/fly-out ability of workers and our first-class camp facilities will position the Horizon Project as "the employer of choice" in the region.

At 34º API gravity, low sulphur and fully sweet, the project is designed to produce one of the higher quality SCO products, somewhat reducing marketing risks.

Finally, this asset has been designed to accommodate future growth. The large footprint allows for easy access to all parts of the plant and ensures that future production expansions would not impact existing operations.

RÉAL J.H. DOUCET
Senior Vice-President,
Oil Sands





2005 ACTIVITY

Phase 1 of the Horizon Project received sanction from the Board of Directors in February 2005 following an extensive front end engineering approach costing over $400 million over a four year period. The high degree of up front project engineering and pre-planning has reduced the risks on "cost-plus" aspects of the project and will mitigate the risk of scope changes on the fixed price portions (targeted at 68% of Phase 1 costs). The pre-engineering and lessons learned from predecessors have also enabled the Company to prepare a detailed development and logistical plan to reduce the scheduling risk.

Significant progress was achieved during 2005 following this sanctioning, with 3-D engineering design models being well advanced in most areas and some plant areas achieving 90% model review stage. In addition, Hazard and Operability reviews were completed with findings being incorporated in plant design. No significant changes occurred during the design.

At December 31, 2005, total procurement progress was at C$3.8 billion in awarded contracts and purchase orders, with a further C$600 million in various stages of the tender process.

Use of modularization and prefabrication in existing construction yards is considered fundamental to overall success of the project. Module fabrication and assembly maintained schedule and just as importantly, in an environment of key transportation restrictions, module transportation remains on schedule. A total of 88 oversized loads were transported to site by year-end, including piperacks and various reactors.

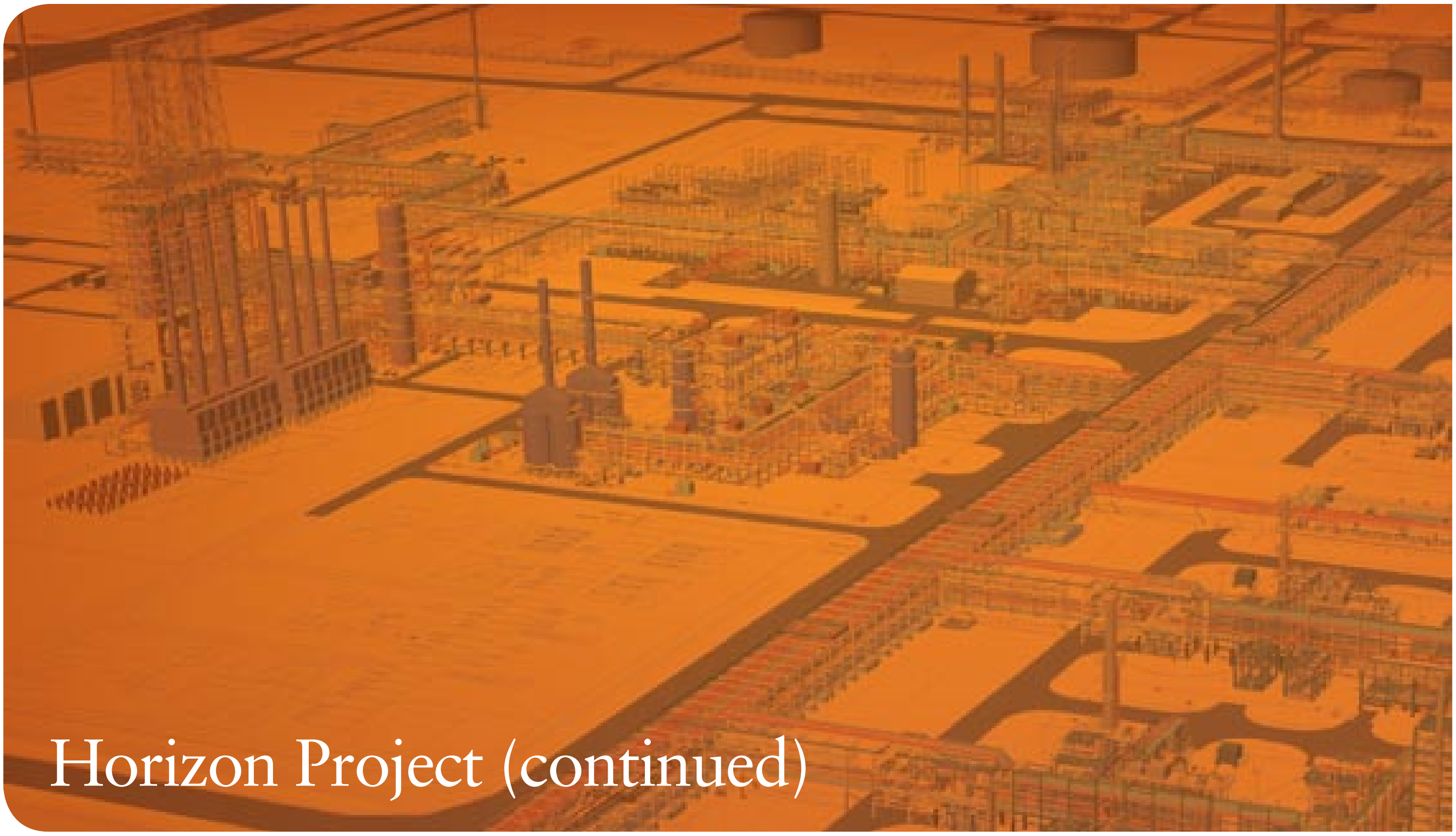
Construction also moved forward in a significant way. During the year several critical path items were completed while on-site safety statistics and performance improved for eleven months in a row and remain well below the Company's targets as benchmarked against other projects in the area.

Site clearing, drainage and deep underground facility installation such as electrical, natural gas, water and sewage were completed during the first half of the year and work on access roads continued throughout the year.

Camps for construction workers progressed significantly with the first camp opening in July 2005 and 72% progress on the second camp, essentially on schedule. Ultimately three 2,000 worker camps will be constructed onsite with a fourth employee camp located offsite. To facilitate the Company's labour strategies, the 737–capable airstrip was completed in September 2005 and now hosts several landings each day.

Also on the plant site, coker and extraction separation cell foundations were completed. Erection of the latter was commenced late in the year with 80% of the required material on site.

Mine overburden removal progressed 10% ahead of plan, with a total of 6.7 million banked cubic meters of material removed. Earthwork for the raw water and recycle water pond systems commence as scheduled.



Horizon Project (continued)

WHAT TO EXPECT IN 2006 AND BEYOND

Activities continue in 2006 with detailed engineering expected to be essentially complete. In addition, we expect to receive and complete the gas/oil reactor and distillation tower and erect critical path equipment such as the coke drums and extraction separation cells.

The main piperack will be substantially completed. In February 2006 the first sections of these piperacks were successfully placed with no rework required. At the first mine pit, construction of the Ore Preparation Plant will commence.

The 2006 Phase 1 construction capital budget of $2.6 billion for the Horizon Project will facilitate major work as articulated. This budget represents an acceleration of spending into 2006, which allows Canadian Natural to capitalize on the opportunities created by having significant work completed during 2005. This serves to modify labour requirements timing and ease the execution of the project. Capital for Phase 1 remains at $6.8 billion, and advancing $400 million from 2007 to 2006 will result in construction progress at the end of 2006 targeted at 55%.

Expenditures of $128 million to initiate the Engineering Design Specification, order certain Phase 2 long-lead items and review the merits of combining Phase 2 and Phase 3 expansions into one combined Phase targeted to commence production in 2011. While not changing overall expected capital costs, this combination will provide enhanced overall economics as it allows full synergies and production to be achieved at an earlier date. The results of this review, and the decision whether to combine the phases, are expected in early 2007.

THE UPSIDE OPPORTUNITY

We believe that our land assets, site layout, size, and the manner in which we have planned this Project will facilitate increases in production beyond the 232 mbbl/d of SCO that is currently in development. Our internal estimates of resource potential, based upon our stratigraphic well drilling program accumulate to approximately 6 billion barrels of mineable bitumen throughout our Horizon leases. To this end, we recently articulated an expanded development plan.

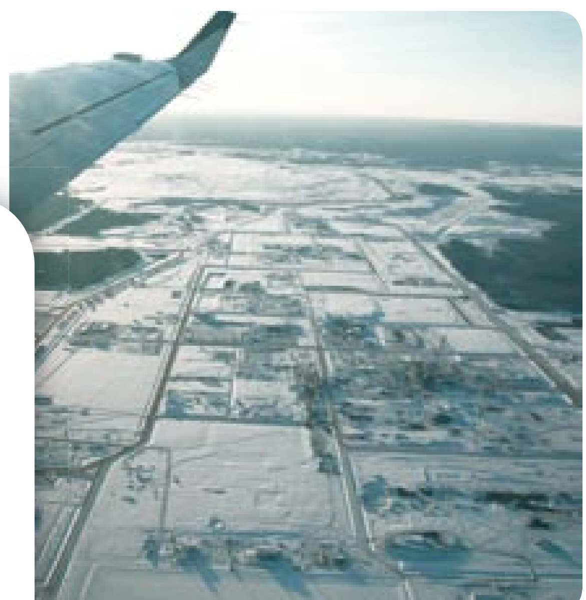
As noted earlier, we are analyzing the merits of combining Phase 2 and Phase 3 expansions into one combined Phase targeted to commence production in 2011. While not changing overall expected capital costs, this combination will provide enhanced overall economics as it allows full synergies and production to be achieved at an earlier date. This change will also facilitate the Company's labour strategies in that it provides a smoother transition from Phase 1, keeps an experienced force on-site and optimizes the projected demand for construction labour.

Beyond Phases 1 to 3 of the Horizon Project, we will evaluate the Phase 4 addition of 125 mbbl/d of new SCO production targeted to commence in 2015 with Phase 5 adding a further 140 mbbl/d targeted to commence in 2017.

In oil sands mining production, the generation of heat is a critical element to success. Engineering design will be completed to consider installation of gasification of the upgrading by-products into Horizon Project Phases 1 to 3 in 2013. This technology would be built into Horizon Project Phase 4 and 5 expansions.

In announcing these expansions, we were cognizant of the need to maintain discipline while capitalizing on available opportunities. Each of these developments:

- Leverages our existing team and experience;
- Provides a natural migration of professional engineering and project management skills;
- Provides a natural migration of construction workers;
- Is financially supported through anticipated cash flow of the Company; and,
- Helps control operating costs in oil sands mining operations through targeted application of gasification technologies.



Year-end reserves

INDEPENDENT EVALUATION

For the year ended December 31, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved and probable crude oil, natural gas liquids ("NGL") and natural gas reserves* and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional assets. Canadian Natural has been granted an exemption from National Instrument 51-101 – Standards of Disclosure for 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. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of this Annual Report. The Company has elected to provide the net present value [(1)] of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information.

For the year ended December 31, 2005, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Oil Sands Project and prepare an Evaluation Report on the Company's proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGL and natural gas reserves.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ 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 conventional crude oil, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

NET CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES

During 2005, proved reserve additions of 251 mmboe replaced 145% of production. This growth was achieved at a 2005 finding and onstream cost of $13.41/boe resulting in a 3 year average finding and onstream cost of $12.55/boe. Proved and probable reserve additions of 337 mmboe replaced 195% of production at a 2005 and 3 year average finding and onstream cost of $9.97/boe and $8.05/boe respectively.

NORTH AMERICA

Proved natural gas reserves increased by 6% to 2.7 tcf and replaced 137% of 2005 production. Similarily, proved crude oil and NGL reserves increased by 7% to 694 mmbbl and replaced 167% of production. The total proved and probable crude oil and NGL reserves increased by 12% to 1,035 mmbbl primarily due to thermal in-situ and Pelican Lake Field developments.

INTERNATIONAL

North Sea proved reserve additions of 13 mmboe were primarily achieved through waterflood design optimization, infill drilling and recompletions. Offshore West Africa proved crude oil and NGL reserves increased by 17% to 134 mmbbl through developments at the Espoir and Baobab fields in Côte D'Ivoire as well as the acquisition of the Olowi Field in Gabon where 15 mmbbl of proved crude oil and NGL reserves were added.

OIL SANDS MINING RESERVES

The Horizon Project's gross proved and probable synthetic crude oil reserves have increased by 88 mmbbl from February 9, 2005 estimates to 2,878 mmbbl due to the incorporation of updated pit limits and mine plans from drilling programs. The reserves are expected to produce over 37 years with first production commencing in 2008.

* Conventional crude oil, NGL and natural gas includes all of the Company's light and medium, heavy and, thermal crude oil, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets.

NET CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES (AFTER ROYALTIES) [2] [3]

	December 31, 2005			
	Proved Developed [4]	Proved Undeveloped [4]	Proved Total [4]	Proved and Probable [5]
Crude oil & NGLs (mmbbl)				
North America	402	292	694	1,035
North Sea	214	76	290	417
Offshore West Africa	80	54	134	206
	696	422	1,118	1,658
Natural gas (bcf)				
North America	2,300	441	2,741	3,548
North Sea	16	13	29	69
Offshore West Africa	10	62	72	110
	2,326	516	2,842	3,727
Total reserves (mmboe)	1,083	509	1,592	2,279
Reserve replacement ratio (%) [6]			145%	195%
Cost to develop ($/boe) [7]				
10% discount	0.79	5.69	2.36	2.55
15% discount	0.67	5.15	2.11	2.25
Present value of conventional reserves ($ millions) [1]				
10% discount	24,275	6,342	30,617	38,682
15% discount	20,939	4,881	25,820	31,642

NET CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES (AFTER ROYALTIES) [2] [3]

	December 31, 2004			
	Proved Developed [4]	Proved Undeveloped [4]	Proved Total [4]	Proved and Probable [5]
Crude oil & NGLs (mmbbl)				
North America	367	281	648	926
North Sea	218	85	303	415
Offshore West Africa	20	95	115	196
	605	461	1,066	1,537
Natural gas (bcf)				
North America	2,213	378	2,591	3,319
North Sea	12	15	27	57
Offshore West Africa	5	67	72	90
	2,230	460	2,690	3,466
Total reserves (mmboe)	976	538	1,514	2,115
Reserve replacement ratio (%) [6]			220%	281%
Cost to develop ($/boe) [7]				
10% discount	0.85	3.58	1.77	1.78
15% discount	0.73	3.27	1.58	1.56
Present value of conventional reserves ($ millions) [1]				
10% discount	13,739	4,399	18,138	22,937
15% discount	11,838	3,440	15,279	18,802

OIL SANDS MINING RESERVES [2] [8] [9]

	December 31, 2005			
	Gross Reserves		Net Reserves	
	Proved Total	Proved and Probable	Proved Total	Proved and Probable
Bitumen (mmbbl)	2,235	3,430	1,848	2,848
Synthetic crude oil (mmbbl)	1,833	2,878	1,626	2,566

NET CONVENTIONAL CRUDE OIL AND NGL RESERVES RECONCILIATION (AFTER ROYALTIES) [2] [3]

Proved reserves (mmbbl)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2003	588	222	85	895
Extensions & discoveries	17	–	–	17
Infill drilling	24	35	–	59
Improved recovery	1	10	–	11
Property purchases	36	38	–	74
Property disposals	–	–	–	–
Production	(66)	(24)	(4)	(94)
Revisions of prior estimates	48	22	34	104
Reserves, December 31, 2004	648	303	115	1,066
Extensions & discoveries	98	–	–	98
Infill drilling	3	3	2	8
Improved recovery	–	–	–	–
Property purchases	–	–	15	15
Property disposals	(3)	–	–	(3)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	18	9	10	37
Reserves, December 31, 2005	**694**	**290**	**134**	**1,118**

Proved and probable reserves (mmbbl)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2003	857	317	133	1,307
Extensions & discoveries	20	–	–	20
Infill drilling	29	49	–	78
Improved recovery	2	10	–	12
Property purchases	49	49	–	98
Property disposals	–	–	–	–
Production	(66)	(24)	(4)	(94)
Revisions of prior estimates	35	14	67	116
Reserves, December 31, 2004	926	415	196	1,537
Extensions & discoveries	200	–	–	200
Infill drilling	3	5	6	14
Improved recovery	–	–	–	–
Property purchases	–	–	17	17
Property disposals	(4)	–	–	(4)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	(20)	22	(5)	(3)
Reserves, December 31, 2005	**1,035**	**417**	**206**	**1,658**

NET CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION (AFTER ROYALTIES) (2) (3)

Proved reserves (bcf)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2003	2,426	62	64	2,552
Extensions & discoveries	334	–	–	334
Infill drilling	74	–	–	74
Improved recovery	6	–	–	6
Property purchases	182	10	–	192
Property disposals	(8)	–	–	(8)
Production	(383)	(18)	(3)	(404)
Revisions of prior estimates	(40)	(27)	11	(56)
Reserves, December 31, 2004	2,591	27	72	2,690
Extensions & discoveries	506	–	–	506
Infill drilling	22	–	–	22
Improved recovery	8	–	–	8
Property purchases	6	–	–	6
Property disposals	(23)	–	–	(23)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	42	9	1	52
Reserves, December 31, 2005	2,741	29	72	2,842

Proved and probable reserves (bcf)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2003	2,919	102	72	3,093
Extensions & discoveries	418	–	–	418
Infill drilling	106	–	–	106
Improved recovery	6	–	–	6
Property purchases	236	18	–	254
Property disposals	(10)	–	–	(10)
Production	(383)	(18)	(3)	(404)
Revisions of prior estimates	27	(45)	21	3
Reserves, December 31, 2004	3,319	57	90	3,466
Extensions & discoveries	645	–	–	645
Infill drilling	23	–	1	24
Improved recovery	14	–	–	14
Property purchases	8	–	–	8
Property disposals	(30)	–	–	(30)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	(20)	19	20	19
Reserves, December 31, 2005	3,548	69	110	3,727

NET CONVENTIONAL FINDING AND ONSTREAM COSTS (AFTER ROYALTIES) (2) (3)

	2005	2004	2003	Three Year Total
Reserve replacement expenditures ($ millions)	3,361	4,259	2,283	9,903
Reserve additions (mmboe) (10)				
Proved	251	354	185	790
Proved and probable	337	453	441	1,231
Finding and onstream costs per boe (11)				
Proved	13.41	12.03	12.34	12.55
Proved and probable	9.97	9.40	5.18	8.05

NET CONVENTIONAL RESERVES CLASSIFICATION BY PRODUCT (AFTER ROYALTIES) (2) (3)

	December 31, 2005			
	Proved Developed (4)	Proved Undeveloped (4)	Proved Total (4)	Proved and Probable (5)
Light crude oil and NGLs				
North America	6%	1%	7%	6%
North Sea	13%	5%	18%	18%
Offshore West Africa	5%	3%	8%	9%
Total	24%	9%	33%	33%
Heavy crude oil				
North America - Primary Heavy	6%	1%	7%	6%
North America - Pelican Lake	3%	2%	5%	5%
North America - Thermal	10%	15%	25%	29%
Total	19%	18%	37%	40%
Total crude oil & NGLs				
North America	25%	19%	44%	46%
North Sea	13%	5%	18%	18%
Offshore West Africa	5%	3%	8%	9%
Total	43%	27%	70%	73%
Natural gas				
North America	24%	5%	29%	26%
North Sea	–	–	–	–
Offshore West Africa	–	1%	1%	1%
Total	24%	6%	30%	27%
Total boe	**67%**	**33%**	**100%**	**100%**

(1) Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Only future development costs and associated material well abandonment liabilities have been applied with the exception of Offshore West Africa where all abandonment liabilities have been included.

(2) Net reserves mean the Company's working interest share of gross reserves after consideration of royalties.

(3) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below as well as constant year-end costs.

Crude oil & NGLs	Company Average Price (C$/bbl)	WTI @ Cushing Oklahoma (US$/bbl)	Hardisty Heavy 12º API (C$/bbl)	North Sea Brent (US$/bbl)
December 31, 2005	46.12	61.04	32.64	58.21
December 31, 2004	32.14	44.04	17.45	40.47
December 31, 2003	32.02	32.56	26.16	30.14

Natural gas	Company Average Price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	Alberta AECO C (C$/mmbtu)	British Columbia Huntingdon Sumas (C$/mmbtu)
December 31, 2005	9.45	10.08	9.99	9.53
December 31, 2004	6.44	6.62	6.78	6.94
December 31, 2003	6.63	5.80	6.88	6.94

A foreign exchange rate of US$0.86/C$1.00 was used in the 2005 evaluation. A foreign exchange rate of US$0.83/C$1.00 was used in the 2004 evaluation. A foreign exchange rate of US$0.77/$C1.00 was used in the 2003 evaluation.

(4) Proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission (SEC) requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(5) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(6) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(7) Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(8) Synthetic crude oil reserves are based on upgrading of the bitumen reserves. The reserve values shown for bitumen and synthetic crude oil are not additive.

(9) Gross reserves mean the total remaining recoverable reserves before consideration of royalties.

(10) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(11) Reserves finding and onstream costs are determined by dividing total capital costs for each year excluding cost associated with head office, abandonments, midstream and the Horizon Project by net reserves additions for that year.

Management's Discussion & Analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists or 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 availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the ability of the Company to attract the necessary labour required to build its projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent, and the Company's course of action would depend upon its assessment of the future considering all information then available.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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 were 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 the Company'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 cash flow from operations, adjusted net earnings from operations, and EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). These financial measures are not defined by generally accepted accounting principles ("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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") 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, 2005. The consolidated financial statements have been prepared in accordance with Canadian GAAP. A reconciliation of Canadian GAAP to United States GAAP is included in note 15 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2005. 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 at the burner tip and does not represent the value equivalency at the well head. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise. The following discussion and analysis refers primarily to the Company's 2005 financial results compared to 2004 and 2003, unless otherwise indicated. In addition, this discussion details the Company's capital program and outlook for 2006. This MD&A is dated February 21, 2006.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
bbl	barrel
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
C$	Canadian dollars
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse Gas
Horizon Project	Horizon Oil Sands Project
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/d	million cubic feet per day
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCO	Synthetic light crude oil
SEC	Securities and Exchange Commission
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCS	Western Canadian Select crude oil blend
WTI	West Texas Intermediate

OBJECTIVE AND STRATEGY

The Company's objective is 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 acquisition of new reserves. The Company accomplishes this objective by having a defined growth and a 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 wealth. The Company effectively allocates its capital by maintaining:

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

(1) Discounted value of conventional crude oil and natural gas reserves and undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14-17° API oil, but receives medium quality crude netbacks due to low operating costs and low royalty rates.

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

- Blending various crude oil streams with diluents into more attractive feedstock;
- Supporting and participating in pipeline expansion or new additions; and
- Supporting and participating in projects that will increase the conversion capacity of heavy crude oil.

Operational discipline and cost control is central to the Company's strategy. By controlling costs consistently throughout all cycles of the industry, the Company believes that it will achieve continued growth. Cost control is attained by developing area knowledge, by core area domination and by maintaining a high working interest in its properties.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Oil Sands Project ("Horizon Project"). The Company believes that it has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery from its conventional crude oil and natural gas growth opportunities. Additionally, the Company's risk management hedge program has been expanded to reduce the risk of volatility in commodity price markets and to support the Company's cash flow for its capital expenditures program throughout the construction period of the Horizon Project.

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 to selectively acquire properties generating future cash flows in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and should provide additional free cash flow during the construction years of the Horizon Project while still achieving targeted returns.

The year ended December 31, 2005, was another successful year in the execution of the Company's strategy. Highlights are as follows:

- Maintained strong levels of net earnings;
- Achieved record levels of adjusted net earnings from operations;
- Achieved record levels of cash flow;
- Completed the disposition of a large portion of its overriding royalty interests, which were considered non-core to the Company's operations, for proceeds of approximately $345 million;
- Completed the subdivision of its common shares on the basis of two for one;
- Increased the quarterly dividend by 20% to $0.06 per common share;
- Purchased 850,000 common shares for a total cost of $45 million under the Company's Normal Course Issuer Bid;
- Achieved record levels of natural gas and crude oil and NGLs production;
- Achieved its annual production guidance for crude oil and NGLs, and natural gas;
- Completed the development of the 57.61% owned and operated Baobab Field offshore Côte d'lvoire West Africa, which commenced production on August 9, 2005 at approximately 30,000 bbl/d net to the Company;
- Completed the acquisition of the permit to develop the Olowi Field, offshore Gabon, West Africa with development plans to proceed in 2006;
- Received Board of Directors' approval of the Horizon Project and completed 19% of Phase 1 construction;

- Signed a key pipeline transportation agreement, which will allow Horizon Project Synthetic Crude Oil ("SCO") to reach the pipeline hub at Edmonton, Alberta;
- Completed all major 2005 milestones on the Horizon Project, before winter' onset;
- Commenced steam injection at Primrose North. First oil production began in January 2006 and is expected to increase to 30,000 bbl/d by the third quarter of 2006;
- Drilled a record 1,634 net wells, excluding stratigraphic test/service wells; and
- Announced a strategy to review the building of a 100% owned and operated upgrader ("Canadian Natural Upgrader") for the Company's in-situ oil sands assets in the Cold Lake to Athabasca region.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial highlights ($ millions, except per common share amounts)	2005	2004	2003
Revenue, before royalties	$ 10,107	$ 7,547	$ 6,155
Net earnings	$ 1,050	$ 1,405	$ 1,403
Per common share			
– basic [1]	$ 1.96	$ 2.62	$ 2.62
– diluted [1]	$ 1.95	$ 2.60	$ 2.53
Adjusted net earnings from operations [2]	$ 2,034	$ 1,405	$ 987
Per common share			
– basic [1]	$ 3.79	$ 2.62	$ 1.84
– diluted [1]	$ 3.78	$ 2.60	$ 1.80
Cash flow from operations [3]	$ 5,021	$ 3,769	$ 3,160
Per common share			
– basic [1]	$ 9.36	$ 7.03	$ 5.88
– diluted [1]	$ 9.33	$ 6.98	$ 5.76
Dividends declared per common share	$ 0.236	$ 0.200	$ 0.150
Total assets	$ 21,852	$ 18,372	$ 14,643
Total long-term liabilities	$ 9,790	$ 9,196	$ 7,277
Capital expenditures, net of dispositions	$ 4,932	$ 4,633	$ 2,506

(1) Restated to reflect two-for-one share split in May 2005.

(2) Adjusted net earnings from operations is a non-GAAP term 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 following reconciliation 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.

($ millions)	2005	2004	2003
Net earnings as reported	$ 1,050	$ 1,405	$ 1,403
Stock-based compensation, net of tax [a]	481	168	136
Unrealized risk management loss (gain), net of tax [b]	607	(27)	–
Unrealized foreign exchange gain, net of tax [c]	(85)	(75)	(274)
Effect of statutory tax rate changes on future income tax liabilities [d]	(19)	(66)	(278)
Adjusted net earnings from operations	$ 2,034	$ 1,405	$ 987

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value, net of taxes, flow through net earnings.

(b) Effective January 1, 2004, the Company adopted a new accounting standard whereby financial instruments not designated as hedges are recorded at fair value on its balance sheet, with changes in fair value, net of taxes, flowing through 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 and are immediately recognized in net earnings.

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. In 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5%. During 2004, the province of Alberta enacted legislation to reduce its corporate income tax rate by 1%. During 2003 the province of Alberta enacted legislation to reduce its corporate income tax rate by 0.5%. Also during 2003, the Canadian federal government enacted legislation to change the taxation of resource income. The federal legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period the deduction for resource allowance is being phased out and a deduction of actual crown royalties paid is being phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the federal resource income tax rate changes.

(3) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. 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. Cash flow from operations may not be comparable to similar measures presented by other companies.

($ millions)	2005	2004	2003
Net earnings	$ 1,050	$ 1,405	$ 1,403
Non-cash items:			
Depletion, depreciation and amortization	2,013	1,769	1,509
Asset retirement obligation accretion	69	51	62
Stock-based compensation	723	249	200
Unrealized risk management activities	925	(40)	–
Unrealized foreign exchange gain	(103)	(94)	(343)
Deferred petroleum revenue tax recovery	(9)	(45)	(9)
Future income tax	353	474	338
Cash flow from operations	$ 5,021	$ 3,769	$ 3,160

The Company achieved record levels of cash flow from operations and production in 2005 as a result of strong operational performance combined with increased commodity prices. The strong operating results are attributable to the Company following its defined growth strategy and to the strong asset base the Company has developed over time through organic growth and accretive acquisitions.

For the year ended December 31, 2005, the Company recorded net earnings of $1,050 million compared to net earnings of $1,405 million for the year ended December 31, 2004 (2003 – $1,403 million). Net earnings for 2005 include unrealized after-tax expenses of $984 million related to the Company's risk management activities and stock-based compensation plans, net of foreign exchange gains and the effect of statutory tax rate changes ($nil for 2004; 2003 –unrealized after-tax income of $416 million). Excluding the effects of these items, adjusted net earnings from operations increased 45% to $2,034 million from $1,405 million in 2004 (2003 – $987 million) due to continuing strong crude oil and natural gas prices as well as record levels of total sales on a boe basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar.

Cash flow from operations reached record levels in 2005. Cash flow from operations increased 33% to $5,021 million ($9.36 per common share), up from $3,769 million ($7.03 per common share) in 2004 (2003 – $3,160 million or $5.88 per common share). The increase in cash flow from operations was due mainly to strong commodity prices and record levels of total sales volume on a boe basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar. In 2005, the Company's average sales price per bbl of crude oil and NGLs increased 23% to $46.86 per bbl from $37.99 per bbl in 2004 (2003 – $32.66 per bbl). The Company's average natural gas price increased 32% to $8.57 per mcf from $6.50 per mcf in 2004 (2003 – $6.21 per mcf).

Production volumes before royalties increased 8% to a record 552,960 boe/d, up from 513,835 boe/d in 2004 (2003 – 458,814 boe/d). The increase in production was due to organic growth from the Company's extensive North America capital expenditure program and the commencement of production from the Baobob Field offshore Côte d'lvoire, as well as the full year impact of accretive acquisitions completed in 2004. Production of crude oil and NGLs before royalties increased 11% to 313,168 bbl/d, up from 282,489 bbl/d in 2004 (2003 – 242,392 bbl/d). Natural gas production before royalties increased 4% to 1,439 mmcf/d, up from 1,388 mmcf/d in 2004 (2003 – 1,299 mmcf/d).

Operating highlights	2005	2004	2003
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	$ 46.86	$ 37.99	$ 32.66
Royalties	3.97	3.16	2.77
Production expense	11.17	10.05	10.28
Netback	$ 31.72	$ 24.78	$ 19.61
Natural gas ($/mcf) [1]			
Sales price [2]	$ 8.57	$ 6.50	$ 6.21
Royalties	1.75	1.35	1.32
Production expense	0.73	0.67	0.60
Netback	$ 6.09	$ 4.48	$ 4.29
Barrel of oil equivalent ($/boe) [1]			
Sales price [2]	$ 48.77	$ 38.45	$ 34.84
Royalties	6.82	5.37	5.20
Production expense	8.21	7.35	7.15
Netback	$ 33.74	$ 25.73	$ 22.49

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

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the most recently completed quarters:
($ millions, except per common share amounts)

2005	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$ 10,107	$ 3,032	$ 2,918	$ 2,164	$ 1,993
Net earnings (loss)	$ 1,050	$ 1,104	$ 151	$ 219	$ (424)
Net earnings (loss) per common share					
– basic [1]	$ 1.96	$ 2.06	$ 0.28	$ 0.41	$ (0.79)
– diluted [1]	$ 1.95	$ 2.06	$ 0.28	$ 0.41	$ (0.79)

2004	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$ 7,547	$ 1,969	$ 2,075	$ 1,865	$ 1,638
Net earnings	$ 1,405	$ 577	$ 311	$ 259	$ 258
Net earnings per common share					
– basic [1]	$ 2.62	$ 1.07	$ 0.58	$ 0.48	$ 0.49
– diluted [1]	$ 2.60	$ 1.06	$ 0.57	$ 0.48	$ 0.48

(1) Restated to reflect two-for-one share split in May 2005.

Quarterly revenues have steadily increased throughout 2004 and 2005. This trend reflects increasing world benchmark crude oil and natural gas prices and increasing sales volumes.

- Prices continued to reflect world-wide economic growth and persistent geopolitical uncertainty, further exacerbated by hurricane activity in the Gulf of Mexico during the third quarters of 2004 and 2005. As a result, the Company's realized crude oil and NGLs price increased from C$34.21 per bbl for the first quarter of 2004 to C$46.38 per bbl for the fourth quarter of 2005. The realized natural gas price increased from C$6.31 per mcf to C$11.67 per mcf for the same periods. A strengthening Canadian dollar relative to the US dollar offset the impact of increasing commodity prices. The US / Canadian dollar average exchange rate increased from 0.76 for the first quarter of 2004 to 0.84 for the fourth quarter of 2005.
- Strong sales volumes in 2005 versus 2004 were also fundamental to the steady increase in revenue, driven by North America's extensive capital program, the commencement of production from the Baobab Field offshore Côte d'lvoire in 2005, as well as the full year impact of accretive acquisitions completed late in 2004. Daily production increased from 476,944 boe/d day in the first quarter of 2004 to 577,505 boe/d for the fourth quarter of 2005.
- The Company acquired certain heavy crude oil properties in its Northern Plains core region in the first quarter of 2004.
- The Company completed the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta in the second quarter of 2004. These properties include further ownership in the Ladyfern natural gas field.
- The Company acquired certain light crude oil producing properties in the Central North Sea in the third quarter of 2004. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma Fields) and B-Block (Balmoral, Stirling and Glamis Fields).
- The Company completed the acquisition of certain resource properties located in Alberta, British Columbia and Saskatchewan in the fourth quarter of 2004.

In addition to commodity prices, sales volumes and acquisitions, net earnings continued to be impacted by:

- The impact of the mark-to-market ("MTM") treatment of the Company's commodity price contracts as part of its commodity hedging program. Steadily increasing commodity prices have resulted in significant realized and unrealized risk management losses as the Company strives to lock in prices and secure cash flow for its capital expenditure program.
- The MTM treatment on its stock-based compensation plan. The Company's strong stock performance has resulted in the recognition of significant stock-based compensation expense.
- Increasing production expense. Higher service costs as a result of increased industry-wide activity in reaction to higher commodity prices as well as the impact of higher crude oil prices on fuel related expenses have resulted in increased costs.
- Corporate income tax rates. During the first quarter of 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. During the third quarter of 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5% effective July 1, 2005. As a result, the North America future income tax liability was reduced by $19 million.

BUSINESS ENVIRONMENT

(Yearly average)	2005	2004	2003
WTI benchmark price (US$/bbl) [1]	$ 56.61	$ 41.43	$ 31.02
Dated Brent benchmark price (US$/bbl)	$ 54.45	$ 38.28	$ 28.83
Differential to LLB blend (US$/bbl)	$ 20.83	$ 13.44	$ 8.55
Differential to LLB blend as a % of WTI	37%	32%	28%
Condensate benchmark price (US$/bbl)	$ 57.25	$ 41.62	$ 31.42
NYMEX benchmark price (US$/mmbtu)	$ 8.56	$ 6.09	$ 5.44
AECO benchmark price (C$/GJ)	$ 8.05	$ 6.43	$ 6.35
US/Canadian dollar average exchange rate (US$)	0.8253	0.7683	0.7135

(1) Refers to West Texas Intermediate crude oil barrel prices at Cushing, Oklahoma.

World light crude oil prices reached all-time highs in 2005, supported by:

- Strong demand growth, particularly in China, India and the United States;
- Ongoing geopolitical uncertainties in Iran, Nigeria, Iraq and Venezuela;
- Production losses in the Gulf of Mexico from hurricanes Katrina and Rita. Many platforms and refineries are not expected to be operational until sometime late in 2006; and
- Restricted crude oil refining capacity, which increased refiners' demand for light crude oil to maximize yields of gasoline and distillates.

West Texas Intermediate ("WTI") averaged US$56.61 per bbl for the year ended December 31, 2005, an increase of 37% compared to US$41.43 per bbl for the year ended December 31, 2004 (2003 – US$31.02 per bbl).

Higher WTI pricing is not fully reflected in the Company's crude oil price realizations. The positive impact of higher WTI prices on the Company's crude oil production continues to be mitigated by wider heavy crude oil differentials, which increased 55% to US$20.83 per bbl for the year ended December 31, 2005 from US$13.44 per bbl for the year ended December 31, 2004 (2003 – $US8.55 per bbl).

Heavy crude oil differentials in 2005 continued to be higher than the long-term average primarily due to physical limitations for demand at refineries. Following hurricanes Katrina and Rita, refiners sought to process lighter barrels to increase their yields of gasoline and distillates, which resulted in the further deterioration of heavy crude oil differentials. Plant turnarounds and maintenance during the year, additional problems at refineries and upgraders, the higher cost of diluents, and the stronger Canadian dollar also mitigated the effect of higher WTI prices on the Company's heavy crude oil price realizations. A strengthening in the Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil production as crude oil prices are based on US dollar denominated benchmarks.

North American natural gas prices also climbed in 2005 due to concerns around supply as well as the impact of higher crude oil prices. NYMEX natural gas prices increased 41% to average US$8.56 per mmbtu for the year ended December 31, 2005, up from US$6.09 per mmbtu for the year ended December 31, 2004 (2003 – $5.44 per mmbtu). AECO natural gas pricing moved directionally with NYMEX, increasing 25% to average $8.05 per GJ for the year ended December 31, 2005, up from $6.43 per GJ for the year ended December 31, 2004 (2003 – $6.35 per GJ).

REVENUE, BEFORE ROYALTIES

Analysis of changes in revenue, before royalties

		Changes due to				Changes due to			
($ millions)	2003	Volumes	Prices	Other	2004	Volumes	Prices	Other	2005
North America									
Crude oil and NGLs	$ 1,953	$ 342	$ 283	$ –	$ 2,578	$ 170	$ 546	$ –	$ 3,294
Natural gas	3,068	207	126	–	3,401	208	1,029	–	4,638
	5,021	549	409	–	5,979	378	1,575	–	7,932
North Sea									
Crude oil and NGLs	873	123	227	–	1,223	31	382	–	1,636
Natural gas	80	5	9	–	94	(59)	(12)	–	23
	953	128	236	–	1,317	(28)	370	–	1,659
Offshore West Africa									
Crude oil and NGLs	141	13	54	–	208	182	86	–	476
Natural gas	14	(1)	1	–	14	(6)	1	–	9
	155	12	55	–	222	176	87	–	485
Subtotal									
Crude oil and NGLs	2,967	478	564	–	4,009	383	1,014	–	5,406
Natural gas	3,162	211	136	–	3,509	143	1,018	–	4,670
	6,129	689	700	–	7,518	526	2,032	–	10,076
Midstream	61	–	–	7	68	–	–	9	77
Intersegment eliminations and other (1)	(35)	–	–	(4)	(39)	–	–	(7)	(46)
Total	$ 6,155	$ 689	$ 700	$ 3	$ 7,547	$ 526	$ 2,032	$ 2	$10,107

(1) Eliminates primarily internal transportation and electricity charges.

Revenue rose 34% to $10,107 million in 2005, up from $7,547 million in 2004 (2003 – $6,155 million). Price increases accounted for 79% of the 2005 increase (2004 – 51%), while volume increases accounted for the remaining 21% (2004 – 49%).

In 2005, 21% of the Company's crude oil and natural gas revenue was generated outside of North America, up from 20% in 2004 (2003 – 18%). North Sea accounted for 16% of crude oil and natural gas revenue in 2005 and 17% in 2004 (2003 – 16%), and Offshore West Africa accounted for 5% of crude oil and natural gas revenue in 2005 and 3% in 2004 (2003 – 2%).

ANALYSIS OF PRODUCT PRICES [1]

	2005	2004	2003
Crude oil and NGLs ($/bbl) [2]			
North America	$ 39.62	$ 33.16	$ 29.40
North Sea	$ 66.57	$ 51.37	$ 42.00
Offshore West Africa	$ 59.91	$ 49.05	$ 36.47
Company average	$ 46.86	$ 37.99	$ 32.66
Natural gas ($/mcf) [2]			
North America	$ 8.65	$ 6.61	$ 6.34
North Sea	$ 3.17	$ 3.73	$ 3.03
Offshore West Africa	$ 5.91	$ 5.25	$ 4.37
Company average	$ 8.57	$ 6.50	$ 6.21
Company average ($/boe) [2]	$ 48.77	$ 38.45	$ 34.84
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	54%	54%	50%
Natural gas	46%	46%	50%

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

Realized crude oil prices increased 23% to average $46.86 per bbl in 2005, up from $37.99 per bbl in 2004 (2003 – $32.66 per bbl). This increase was primarily due to higher benchmark world crude oil prices, as well as an increased proportion of crude oil and NGLs sales coming from Offshore West Africa, offset by higher heavy crude oil differentials and a stronger Canadian dollar. Higher benchmark crude oil prices were primarily driven by increased demand in countries such as China, India and the United States as well as concerns around supply, which increased pricing volatility.

The Company's realized natural gas price increased 32% to average $8.57 per mcf in 2005, up from $6.50 per mcf in 2004 (2003 – $6.21 per mcf), primarily due to supply concerns and a continued strengthening in benchmark North America gas pricing.

NORTH AMERICA

North America realized crude oil prices increased 19% to average $39.62 per bbl in 2005, up from $33.16 per bbl in 2004 (2003 – $29.40 per bbl). The increase in the realized crude oil price in 2005 was mainly due to higher benchmark crude oil prices, partially offset by wider heavy crude oil differentials and the strengthening Canadian dollar.

North America 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 geographic markets, and working with refiners to add incremental heavy crude oil conversion capacity. As part of an industry initiative to develop new blends of Western Canadian crude oils, the Company has access to blending capacity of up to 140,000 bbl/d. The Company is currently contributing approximately 139,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy crude oil with premium quality asphalt characteristics and has an API of 19°-22°. Volumes of the new blend are expected to grow, with the potential to become a new benchmark for North American markets in addition to WTI. The Company has committed to 25,000 bbl/d of capacity on the Corsicana Pipeline, which will carry crude oil to the Gulf of Mexico and is expected to be in operation late in the first quarter of 2006. The Corsicana Pipeline is made up of a series of segments extending from Patoka Illinois to Nederland Texas, near the US Gulf Coast.

North America realized natural gas prices increased 31% to average $8.65 per mcf for the year ended December 31, 2005, up from $6.61 per mcf for the year ended December 31, 2004 (2003 – $6.34 per mcf). This increase was due to supply concerns and fluctuations in the North America benchmark natural gas price in response to crude oil pricing.

A comparison of the price received for the Company's North America production is as follows:

	2005	2004	2003
Wellhead price [1][2]			
Light crude oil and NGLs (C$/bbl)	$ 58.41	$ 45.90	$ 37.59
Pelican Lake crude oil (C$/bbl)	$ 38.39	$ 32.12	$ 28.05
Primary heavy crude oil (C$/bbl)	$ 33.53	$ 28.99	$ 26.21
Thermal heavy crude oil (C$/bbl)	$ 32.29	$ 29.00	$ 25.56
Natural gas (C$/mcf)	$ 8.65	$ 6.61	$ 6.34

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

NORTH SEA

North Sea realized crude oil prices increased 30% to average $66.57 per bbl for the year ended December 31, 2005, up from $51.37 per bbl for the year ended December 31, 2004 (2003 – $42.00 per bbl). The increase in the realized crude oil price compared to 2004 was due mainly to higher world benchmark crude oil prices and a narrowing of the average Brent differential, offset by the strengthening Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 22% to average $59.91 per bbl for the year ended December 31, 2005, an increase from $49.05 per bbl for the year ended December 31, 2004 (2003 – $36.47 per bbl). The increase in realized crude oil prices from 2004 was primarily due to higher world benchmark crude oil prices offset by the strengthening Canadian dollar.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place, referred to as "liftings" in this MD&A. For production where revenue has not yet been recognized, the related crude oil inventory volumes, by segment, were as follows at December 31, 2005:

(bbl)	2005
North America, related to Corsicana pipeline line fill	484,157
North Sea, related to timing of liftings	747,141
Offshore West Africa, related to timing of liftings, net of government entitlement to profit oil	412,841
	1,644,139

At December 31, 2004, variances between production volumes and liftings were not significant.

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2005	2004	2003
Crude oil and NGLs (bbl/d)			
North America	221,669	206,225	174,895
North Sea	68,593	64,706	56,869
Offshore West Africa	22,906	11,558	10,628
	313,168	282,489	242,392
Natural gas (mmcf/d)			
North America	1,416	1,330	1,245
North Sea	19	50	46
Offshore West Africa	4	8	8
	1,439	1,388	1,299
Total barrel of oil equivalent (boe/d)	552,960	513,835	458,814
Product Mix (%)			
Light crude oil and NGLs	26%	24%	25%
Pelican Lake crude oil	4%	4%	5%
Primary heavy crude oil	17%	19%	15%
Thermal heavy crude oil	10%	8%	8%
Natural gas	43%	45%	47%

DAILY PRODUCTION, NET OF ROYALTIES

	2005	2004	2003
Crude oil and NGLs (bbl/d)			
North America	191,751	180,011	152,444
North Sea	68,487	64,598	56,928
Offshore West Africa	22,293	11,221	10,314
	282,531	255,830	219,686
Natural gas (mmcf/d)			
North America	1,125	1,048	976
North Sea	18	50	46
Offshore West Africa	4	7	8
	1,147	1,105	1,030
Total barrel of oil equivalent (boe/d)	473,742	440,022	391,361

Daily production and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis. Production net of royalties is presented for information purposes only.

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 crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Record levels of total crude oil and natural gas production averaged 552,960 boe/d for the year ended December 31, 2005, an increase of 8% or 39,125 boe/d from 513,835 boe/d for the year ended December 31, 2004 (2003 – 458,814 boe/d). The increase in production year over year was due to organic growth from the Company's extensive North America capital expenditure program and the commencement of production from the Baobab Field offshore Côte d'Ivoire in 2005, as well as the full year impact of accretive acquisitions completed in 2004.

Total record crude oil and NGLs production for the year ended December 31, 2005 increased 11% to 313,168 bbl/d from 282,489 bbl/d for the year ended December 31, 2004 (2003 – 242,392 bbl/d). Crude oil and NGLs production for 2005 was in line with the Company's guidance of 308,000 to 316,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the year ended December 31, 2005 increased 4% or 51 mmcf/d to average 1,439 mmcf/d compared to 1,388 mmcf/d for the year ended December 31, 2004 (2003 – 1,299 mmcf/d). Growth in natural gas production in Western Canada was negatively affected by the early arrival of spring breakup and weather related delays due to unusually wet conditions as well as an overall increase in industry activity. The market for the necessary oilfield services and material has become increasingly competitive, resulting in drilling, completion, tie-in and maintenance delays. Natural gas production for 2005 was in line with the Company's guidance of 1,436 to 1,448 mmcf/d.

The Company expects annual production levels in 2006 to average 1,468 to 1,551 mmcf/d of natural gas and 335,000 to 373,000 bbl/d of crude oil and NGLs. First quarter 2006 production is expected to be between 1,426 and 1,475 mmcf/d of natural gas and 306,000 to 334,000 bbl/d of crude oil and NGLs.

NORTH AMERICA

North America crude oil and NGLs production for the year ended December 31, 2005 increased 7% or 15,444 bbl/d to average 221,669 bbl/d, up from 206,225 bbl/d for the year ended December 31, 2004 (2003 – 174,895 bbl/d). The increase in crude oil and NGLs production was mainly due to the timing of Primrose production cycles and the positive results of the Pelican Lake waterflood project.

North America natural gas production for the year ended December 31, 2005 increased 6% or 86 mmcf/d to average 1,416 mmcf/d, up from 1,330 mmcf/d in 2004 (2003 – 1,245 mmcf/d). Natural gas production increased as a result of organic growth and the full year impact of accretive property acquisitions in 2004, but was negatively impacted by the early arrival of spring breakup and weather related delays due to unusually wet conditions during the summer months. In addition to weather related factors, production growth was also negatively impacted by the increased demand for oilfield services and materials, which caused delays in the timing of production being brought on stream.

NORTH SEA

North Sea crude oil production for the year ended December 31, 2005 was 68,593 bbl/d, an increase of 6% from 64,706 bbl/d for 2004 (2003 – 56,869 bbl/d). Production levels were in line with expectations, reflecting anticipated curtailments at the Lyell Field and the Columba B and E Terraces, continued restrictions at Murchison Field due to third party natural gas export facilities and production declines at the satellite Playfair Field.

Natural gas production in the North Sea for the year ended December 31, 2005 decreased 62% to average 19 mmcf/d, down from 50 mmcf/d for the year ended December 31, 2004 (2003 – 46 mmcf/d). The decrease in natural gas production was due to the commencement of the natural gas reinjection program in the Banff Field in the Central North Sea late in 2004. The natural gas reinjection project is expected to result in an overall increase in the reservoir recovery, but resulted in reductions in natural gas production in 2005.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production for the year ended December 31, 2005 increased 98% to 22,906 bbl/d from 11,558 bbl/d for the year ended December 31, 2004 (2003 – 10,628 bbl/d). The production increase was primarily due to commencement of production from the 57.61% owned and operated Baobab Field in August 2005, as well as increased production from additional infill wells drilled in East Espoir.

ROYALTIES

		2005		2004		2003
Crude oil and NGLs ($/bbl) (1)						
North America	$	5.37	$	4.21	$	3.79
North Sea	$	0.10	$	0.08	$	(0.03)
Offshore West Africa	$	1.62	$	1.43	$	1.08
Company average	$	3.97	$	3.16	$	2.77
Natural gas ($/mcf) (1)						
North America	$	1.78	$	1.40	$	1.38
North Sea	$	–	$	–	$	–
Offshore West Africa	$	0.16	$	0.15	$	0.13
Company average	$	1.75	$	1.35	$	1.32
Company average ($/boe) (1)	$	6.82	$	5.37	$	5.20
Percentage of revenue (2)						
Crude oil and NGLs		8%		8%		9%
Natural gas		20%		21%		21%
Boe		14%		14%		15%

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

NORTH AMERICA

North America crude oil and NGLs royalties per bbl for the year ended December 31, 2005 increased from 2004 primarily due to higher benchmark crude oil prices, offset by wider heavy crude oil differentials and a strengthening Canadian dollar. Royalty rates are expected to increase in the future as a result of the Primrose South Field payout expected to occur late in 2006 or early 2007.

Natural gas royalties increased from 2004 due to higher benchmark natural gas prices, offset by a stronger Canadian dollar and adjustments to royalty rates related to prior years.

NORTH SEA

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining North Sea royalty represents a gross overriding royalty on the Ninian Field. In 2003, the Company received a refund of royalties previously provided.

OFFSHORE WEST AFRICA

Offshore West Africa production is governed by the terms of Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. These revenues are reported as sales revenue. The Government's share of profit revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. Based on current projections, the Espoir Field and the Baobab Field are expected to reach payout in 2007, which will increase royalty rates and current income taxes in accordance with the PSCs.

PRODUCTION EXPENSE

		2005		2004		2003
Crude oil and NGLs ($/bbl) (1)						
North America	$	10.49	$	8.94	$	9.14
North Sea	$	14.94	$	14.03	$	14.07
Offshore West Africa	$	6.50	$	7.59	$	8.68
Company average	$	11.17	$	10.05	$	10.28
Natural gas ($/mcf) (1)						
North America	$	0.71	$	0.62	$	0.57
North Sea	$	2.44	$	2.07	$	1.33
Offshore West Africa	$	1.05	$	1.33	$	1.39
Company average	$	0.73	$	0.67	$	0.60
Company average ($/boe) (1)	$	8.21	$	7.35	$	7.15

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

The Company continues to experience increasing production expense in 2006, reflecting industry cost pressures in all of its operating areas.

NORTH AMERICA

North America crude oil and NGLs production expense per bbl for the year ended December 31, 2005 increased by 17% from 2004. The increase was primarily due to higher industry wide service costs, higher fuel related expenses, and a larger portion of the Company's crude oil volumes being comprised of higher cost thermal crude oil in 2005 versus 2004, offset by the positive impact of higher volumes relative to fixed costs.

North America natural gas production expense per mcf for the year ended December 31, 2005 increased from the comparable periods in 2004. The increase from 2004 was due to the service and commodity cost pressures previously noted, offset by the positive impact of higher volumes relative to fixed costs.

NORTH SEA

North Sea crude oil production expense varied on a per barrel basis from 2004 primarily due to the timing of maintenance work, the changes in production volumes on a relatively fixed cost base, the timing of liftings from various fields and the impact of production being diverted from the Kyle Field to the Banff floating production storage and offtake vessel ("FPSO").

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expenses are largely fixed in nature and fluctuated on a per barrel basis from 2004 due to changes in volumes. Production expenses for the year ended December 31, 2005 compared to 2004 were primarily impacted by the commencement of production from the Baobab Field in August 2005.

MIDSTREAM

($ millions)	2005	2004	2003
Revenue	$ 77	$ 68	$ 61
Production expense	24	20	15
Midstream cash flow	53	48	46
Depreciation	8	7	7
Segment earnings before taxes	$ 45	$ 41	$ 39

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.

Earnings and cash flow attributable to midstream assets have increased marginally from 2004 primarily due to increased heavy crude oil throughput volumes and increased revenue from the Company's cogeneration plant.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

($ millions, except per boe amounts) (2)	2005	2004	2003
North America	$ 1,595	$ 1,444	$ 1,209
North Sea	306	265	252
Offshore West Africa	104	53	41
Expense	$ 2,005	$ 1,762	$ 1,502
$/boe	$ 10.02	$ 9.37	$ 8.96

(1) DD&A excludes depreciation on midstream assets.
(2) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") for the year ended December 31, 2005 increased in total and on a boe basis from 2004. The increase in DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the fair value allocation of the acquisition costs associated with acquisitions completed late in 2004, future abandonment costs associated with the acquisition of additional properties in the North Sea, higher estimated future costs to develop the Company's proved undeveloped reserves in the North Sea and the commencement of production from the Baobab Field in August 2005.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) (1)	2005	2004	2003
North America	$ 34	$ 28	$ 26
North Sea	34	22	36
Offshore West Africa	1	1	–
Expense	$ 69	$ 51	$ 62
$/boe	$ 0.34	$ 0.27	$ 0.37

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

Accretion expense is the increase in the carrying amount of the asset retirement obligations due to the passage of time. Asset retirement obligation accretion expense for North America increased $6 million or 21% from 2004, primarily due to increased activity in the conventional drilling program and increased requirements under provincial reclamation legislation. Accretion expense for the North Sea increased $12 million or 55% from 2004, largely due to the impact of additional retirement obligations related to property acquisitions completed late in 2004.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) [2]		2005		2004[1]		2003
Net expense	$	151	$	125	$	87
$/boe	$	0.75	$	0.66	$	0.52

(1) Restated to conform to current year presentation.
(2) Amounts expressed on a per unit basis are based on sales volumes.

Net administration expense for the year ended December 31, 2005 increased in total and on a boe basis from the year ended December 31, 2004 primarily due to higher staffing levels associated with the Company's expanding asset base and costs associated with the Company's Share Bonus Plan.

The Share Bonus Plan incorporates employee share ownership in the Company while reducing the granting of stock options and the dilution of current Shareholders. Under the plan, cash bonuses awarded based on Company and employee performance are subsequently used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. For the year ended December 31, 2005, the Company recognized $17 million of compensation expense under the Share Bonus Plan (December 31, 2004 – $10 million; 2003 – $nil).

STOCK-BASED COMPENSATION

($ millions)		2005		2004		2003
Stock-based compensation expense	$	723	$	249	$	200

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $723 million ($481 million after tax) stock-based compensation expense for the year ended December 31, 2005 in connection with the 125% appreciation in the Company's share price (December 31, 2005 – C$57.63; December 31, 2004 – C$25.63; December 31, 2003 – C$16.34; December 31, 2002 – C$11.70). As required by GAAP, the Company's outstanding stock options are valued 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. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project (2005 – $101 million; 2004 – $21 million; 2003 – $10 million). The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2005. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2005, the Company paid $227 million for stock options surrendered for cash settlement (December 31, 2004 – $80 million; 2003 – $31 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) [1]		2005		2004		2003
Interest expense	$	149	$	189	$	201
$/boe	$	0.74	$	1.01	$	1.20
Average effective interest rate		5.6%		5.2%		5.8%

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

Net interest expense decreased on a total and boe basis for the year ended December 31, 2005 from 2004 primarily due to the capitalization of construction period interest related to the Horizon Project in 2005 of $72 million (2004 and 2003 – $nil). Pre-capitalization interest increased from 2004 mainly due to higher interest rates and carrying charges, offset by decreased average debt levels and the impact of the strengthening Canadian dollar, which decreased interest expense attributable to the Company's US dollar denominated debt securities.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the consolidated balance sheets each period with the offset reflected in risk management activities in the statements of earnings.

The Company formally documents all 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 enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements 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 amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

Cross currency swap agreements 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. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been designated as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings immediately.

($ millions)	2005	2004	2003
Realized loss (gain)			
Crude oil and NGLs financial instruments	$ 753	$ 501	$ 95
Natural gas financial instruments	283	5	88
Interest rate swaps	(9)	(32)	(35)
	$ 1,027	$ 474	$ 148
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	$ 847	$ (47)	$ –
Natural gas financial instruments	77	–	–
Interest rate swaps	1	7	–
	$ 925	$ (40)	$ –
Total	$ 1,952	$ 434	$ 148

The realized loss from crude oil and NGLs and natural gas financial instruments decreased the Company's average realized prices as follows:

	2005	2004	2003
Crude oil and NGLs ($/bbl) (1)	$ 6.68	$ 4.85	$ 1.07
Natural gas ($/mcf) (1)	$ 0.54	$ 0.01	$ 0.19

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

The realized gain on non-designated interest rate swaps would have decreased the Company's reported interest expense as follows:

($ millions, except interest rates)	2005	2004	2003
Interest expense as reported	$ 149	$ 189	$ 201
Less: realized risk management gain	(9)	(32)	(35)
	$ 140	$ 157	$ 166
Average effective interest rate	5.2%	4.4%	4.8%

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, unrealized risk management expense reflects, at the balance sheet date, the implied price differentials for the non-designated hedges for future years. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $925 million ($607 million after tax) unrealized loss on its risk management activities for the year ended December 31, 2005 (2004 – a $40 million gain or $27 million after tax; 2003 – $nil).

The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

In addition to the risk management liability recognized on the balance sheet at December 31, 2005, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $990 million (December 31, 2004 – net unrecognized asset of $33 million).

Details relating to outstanding derivative financial instruments at December 31, 2005 are disclosed in note 10 to the Company's audited annual consolidated financial statements as at December 31, 2005.

FOREIGN EXCHANGE

($ millions)	2005	2004	2003
Realized foreign exchange (gain) loss	$ (29)	$ 3	$ 8
Unrealized foreign exchange gain	(103)	(94)	(343)
Total	$ (132)	$ (91)	$ (335)

The Company's results are affected by the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A 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 lower 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 will result in higher revenue from the sale of the Company's production. Production expenses are also subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar related to North Sea operations. 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.

In 2005, the majority of the realized foreign exchange gain was the result of the repayment of the Company's US dollar preferred securities. In addition, net foreign exchange gains were realized on foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange gain is related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$0.8577 compared to US$0.8308 at December 31, 2004 (2003 – US$0.7738).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in Shareholders' equity in the consolidated balance sheets.

TAXES

($ millions, except income tax rates)	2005	2004	2003
Taxes other than income tax			
Current	$ 203	$ 210	$ 116
Deferred	(9)	(45)	(9)
Total	$ 194	$ 165	$ 107
Current income tax			
North America – Current income tax	$ 82	$ 89	$ 43
North America – Large Corporations Tax	16	11	16
North Sea	155	2	23
Offshore West Africa	32	13	10
Other	1	1	–
Total	$ 286	$ 116	$ 92
Future income tax	$ 353	$ 474	$ 338
Effective income tax rate	37.8%	29.6%	23.5%

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian provincial capital taxes and surcharges. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships, with the related income taxes payable in a subsequent year. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary upon the nature and amount of capital expenditures incurred in Canada.

The North Sea current income tax expense for 2005 increased from 2004 due mainly to higher realized product prices, increased sales volumes and the deductibility in 2004 of the cost of assets acquired in the UK. In December 2005, the UK government announced plans to double the supplementary charge on profits from UK North Sea crude oil and natural gas production to 20%. If enacted, the increased North Sea supplementary charge would increase the Company's income tax rate in the North Sea from 40% to 50%. The supplementary charge excludes any deduction for financing costs. A charge has not been reflected in 2005 net earnings as the proposed change has not been substantively enacted. If enacted in 2006, the Company anticipates that this rate change will result in a charge to future income taxes in the amount of $111 million.

During 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5% effective July 1, 2005. As a result, the North America future income tax liability was reduced by $19 million. In 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. In 2003, the Federal Government enacted legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the phased elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid.

The following table shows the effect of non-recurring benefits on income taxes:

($ millions, except income tax rates)	2005	2004	2003
Income tax as reported			
Current income tax	$ 286	$ 116	$ 92
Future income tax expense	353	474	338
	639	590	430
Provincial corporate tax rate reductions	19	66	31
Federal corporate tax rate reductions	–	–	247
Total	$ 658	$ 656	$ 708
Expected effective income tax rate before non-recurring benefits	39.0%	32.9%	38.6%

The effective income tax rate for 2005 increased over 2004 due to the effects of the phased elimination of the resource allowance and the phased deductibility of crown royalties. It is anticipated that in 2006, based on budgeted prices and the current availability of tax pools, the Company is expected to be cash taxable in Canada in the amount of $110 million to $170 million.

CAPITAL EXPENDITURES [1]

($ millions)	2005	2004	2003
Expenditures on property, plant and equipment			
Net property acquisitions [2]	$ (320)	$ 1,835	$ 336
Land acquisition and retention	254	120	154
Seismic evaluations	132	89	77
Well drilling, completion and equipping	2,000	1,394	1,194
Pipeline and production facilities	1,295	821	522
Total net reserve replacement expenditures	3,361	4,259	2,283
Horizon Project:			
Phase 1 construction costs	1,329	–	–
Capitalized interest and other	170	291	152
Total Horizon Project	1,499	291	152
Midstream	4	16	11
Abandonments [3]	46	32	40
Head office	22	35	20
Total net capital expenditures	$ 4,932	$ 4,633	$ 2,506
By segment			
North America	$ 2,530	$ 3,355	$ 1,769
North Sea	387	608	338
Offshore West Africa	439	295	176
Other	5	1	–
Horizon Project	1,499	291	152
Midstream	4	16	11
Abandonments [3]	46	32	40
Head office	22	35	20
Total	$ 4,932	$ 4,633	$ 2,506

(1) The net capital expenditures do not include non-cash property, plant and equipment additions or disposals.
(2) Includes Business Combinations. The 2004 comparative figure includes $26 million in non-cash consideration.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company focuses 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 the year ended December 31, 2005 were $4,932 million compared to $4,633 million for the year ended December 31, 2004 (2003 – $2,506 million). During 2005, the Company continued to make significant progress on its larger, future-growth projects, most notably the Horizon Project, while maintaining its focus on existing assets. The Company drilled a total of 1,882 net wells in 2005 consisting of 890 natural gas wells, 627 crude oil wells, 248 stratigraphic test and service wells, and 117 wells that were dry. This compared to 1,449 net wells drilled in 2004 (2003 – 1,793 net wells). The Company achieved an overall success rate of 93%, excluding stratigraphic test and service wells (2004 and 2003 – 91%).

NORTH AMERICA

North America accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2005 compared to approximately 80% in 2004 (2003 – 79%).

During 2005, the Company drilled 975 net wells targeting natural gas, including 228 wells in Northeast British Columbia, 238 wells in the Northern Plains region, 166 wells in Northwest Alberta, and 343 wells in the Southern Plains region. The Company also drilled 642 net wells targeting crude oil during 2005. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 360 heavy crude oil wells, 84 Pelican Lake crude oil wells, 109 thermal crude oil wells, and 7 light crude oil wells were drilled. Another 82 light crude oil wells were drilled during the year in the Company's other regions.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal projects, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. The Primrose North expansion was substantially completed in 2005 with total capital expenditures of approximately $300 million incurred. Initial steaming commenced in November 2005 and first crude oil production began in January 2006.

In 2004, the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The development application was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company expects construction to begin in 2007, with initial steaming scheduled for January 2009.

Development at Pelican Lake continued on track in 2005, with 84 wells being drilled and production increasing from approximately 18,000 bbl/d to approximately 28,000 bbl/d over the course of the year. The waterflood conversion project is on schedule with production response exceeding expectations. The Company plans to enhance the waterflood process through utilization of Polymer Flood technology. A Polymer Flood pilot has been in operation since May 2005 with positive results. The drilling of 150 horizontal wells is planned for 2006.

During 2005, the Company sold a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario that were considered non-core to its operations, for proceeds of approximately $345 million, after giving effect to anticipated adjustments.

Above average temperatures have continued into 2006. Accordingly, the Company is leveraging its deep drilling inventory and optimizing drilling plans to adjust for road bans and/or site access issues. Despite these challenges the Company still expects to complete the majority of its winter drilling program. However, the risk remains for an early spring breakup which could significantly delay tie-ins of many of these new wells. In 2006, the Company's overall drilling activity in North America is expected to be comprised of approximately 1,139 net natural gas wells and 697 net crude oil wells excluding stratigraphic test/service wells.

HORIZON PROJECT

On February 9, 2005 the Board of Directors of the Company unanimously approved the Company to proceed with Phase 1 of the Horizon Project.

The Horizon Project has continued on schedule and on budget. Specifically, as at December 31, 2005:

- Phase 1 Horizon Project construction was 19% complete;
- The detailed engineering work was on schedule, with 3-D engineering models progressing as planned;
- The Company awarded $3.8 billion of contracts and purchase orders, with a further $600 million in various stages of the tender process; and
- Approximately 1,700 people were on site and functional.

Major activities for 2006 will include:

- Substantial completion of detailed engineering;
- Completion and setting of main piperack modules;
- Receiving and erecting of critical equipment;
- Beginning construction of ore preparation plant; and
- Substantial completion of foundations in each area.

First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008. The Horizon Project is in the early stages of construction.

NORTH SEA

The Company continued in 2005 with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2005, 14 net wells were drilled, consisting of 12 net crude oil wells, 1 net dry well and 1 net service well, with an additional 2.9 net wells drilling at quarter-end.

In anticipation of the 2005 program of infill drilling, workovers, and third party business on the T and B Blocks, the Company completed a major refurbishment of the Tiffany platform drilling rig, which is facilitating a two-well program targeting unswept areas of the field. The first of these two wells was drilled and completed late in 2005.

Production from the Kyle Field was diverted to the Banff FPSO during 2005. Under the terms of an early termination agreement, the existing Kyle FPSO was released in September 2005. The consolidation of these production facilities is expected to result in lower combined operating costs from these fields and may ultimately extend field lives for both fields.

OFFSHORE WEST AFRICA

Offshore West Africa capital expenditures include the development of the 57.61% owned and operated Baobab Field, which commenced production on August 9, 2005 at approximately 30,000 bbl/d net to the Company. Upon completion of drilling additional wells in 2006, production levels are expected to achieve approximately 35,000 bbl/d net to the Company.

In East Espoir, two of the four infill wells scheduled for drilling were completed during 2005, with the remainder expected to be completed in 2006. The drilling of these wells was a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources and production. The West Espoir drilling tower, which will facilitate development drilling of the reservoir, is on site and was installed in late 2005. This project is progressing on time and on budget with first crude oil expected in 2006, increasing to approximately 13,000 boe/d once fully developed.

The Company purchased a 100% operator interest in the Olowi PSC offshore Gabon in October 2005 and received approval of its development plan for this acquisition subsequent to year end. Development plans include a FPSO handling input from two or three shallow-water producing platforms. Development is expected to begin late in 2006, with first oil expected late in 2008 at a rate of approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2005	2004	2003
Working capital deficit (1)	$ 1,774	$ 652	$ 505
Long-term debt	$ 3,321	$ 3,538	$ 2,748
Shareholders' equity			
Share capital	$ 2,442	$ 2,408	$ 2,353
Retained earnings	5,804	4,922	3,650
Foreign currency translation adjustment	(9)	(6)	3
Total	$ 8,237	$ 7,324	$ 6,006
Debt to cash flow (2)	0.7x	1.0x	0.9x
Debt to EBITDA (3)	0.6x	0.9x	0.8x
Debt to book capitalization (4)	28.7%	33.8%	32.8%
Debt to market capitalization	9.7%	21.4%	25.1%
After tax return on average common shareholders' equity (5)	14.3%	21.4%	25.6%
After tax return on average capital employed (6)	10.4%	15.3%	17.1%

(1) Calculated as current assets less current liabilities.
(2) Calculated as current and long-term debt; divided by cash flow from operations for the year.
(3) Calculated as current and long-term debt; divided by earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities for the year.
(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 net earnings for the year as a percentage of average common shareholders' equity for the period.
(6) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year.

The Company's capital resources at December 31, 2005 consist primarily of cash flow from operations and available credit facilities. 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 credit facilities and raise new debt is dependent upon these factors, maintaining an investment grade debt rating and the condition of capital and credit markets. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its five and ten year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt, will be sufficient to sustain its operations and support its growth strategy.

At December 31, 2005 the Company had undrawn bank lines of credit of $3,285 million. These credit lines are supported by credit facilities, which if not extended, mature in 2008, 2009 and 2010.

At December 31, 2005, the Company's working capital deficit was $1,774 million and included the current portion of other long-term liabilities of $1,471 million, comprised of stock-based compensation of $629 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $842 million. The settlement of the stock-based compensation liability is dependant upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

The Company is committed to maintaining a strong financial position. In 2005, strong operational results and high commodity prices resulted in debt to book capitalization levels of 28.7%. The Company believes it has the necessary financial capacity to complete the

Horizon Project while at the same time not compromising delivery of conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to December 31, 2005, such as Baobab, Primrose North and West Espoir should provide identified growth in production volumes in 2006 through 2008, and are expected to generate incremental free cash flows during this period.

In January 2005, the Board of Directors authorized the expansion of the Company's commodity hedging program to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow for its capital expenditures program through the Horizon Project construction period. This expanded program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 75% of budgeted 2006 crude oil volumes have been hedged through the use of collars. Approximately 60% of budgeted 2006 natural gas volumes have similarly been hedged through the use of collars. In addition, for 2007, put options have been acquired on 200,000 bbl/d at an average floor price of US$47.50 and a further 100,000 bbl/d at an average floor price of US$28.00. The Company has not hedged any production volumes beyond 2007. The Company continues to evaluate the need for further hedging in 2007 and beyond, given continuing capital requirements for Horizon and other capital projects.

LONG-TERM DEBT

Long-term debt at December 31, 2005 amounted to $3,321 million. The debt to EBITDA ratio decreased to 0.6x and the debt to book capitalization decreased to 28.7% compared to a debt to EBITDA ratio of 0.9x and a debt to book capitalization of 33.8% in 2004. These ratios are currently below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 35% to 45%.

OPERATING FACILITIES

As at December 31, 2005 the Company had in place unsecured syndicated bank credit facilities of $3,425 million, comprised of:

- a $100 million operating demand facility;
- a two-tranche revolving credit and term loan facility of $1,825 million; and
- a 5-year revolving and term loan facility of $1,500 million.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If not extended, the full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit and term loan facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. These facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2005, was 5.44% (2004 – 3.47%).

The Company also has an unsecured £15 million demand overdraft credit facility for the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, as at December 31, 2005 letters of credit aggregating $24 million have been issued.

MEDIUM-TERM NOTES

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program.

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

SENIOR UNSECURED NOTES

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes. The 6.42% senior unsecured notes were repaid in May 2004.

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Agreement.

US DOLLAR DEBT SECURITIES

In June 2005, the Company filed a short form shelf prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014.

The ratings of the Company's debt securities and its relationships with principal banks are important to the Company as it continues to expand and grow. Hence, it is the Company's management intention to maintain a strong balance sheet and financial position. The Company's debt securities are rated "Baa1" with a stable outlook by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation ("S&P") and "BBB(high)" with a stable trend by Dominion Bond Rating Services Limited. S&P assigns a rating outlook to the Company and not to the individual debt intruments. S&P has assigned a negative outlook to the Company.

SHARE CAPITAL

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. As at December 31, 2005, there were 536,348,000 common shares outstanding. As at February 21, 2006, the Company had 537,156,000 common shares outstanding.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 26,818,012 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at December 31, 2005, the Company had purchased 850,000 common shares at an average price of $53.29 per common share for a total cost of $45 million.

In January 2006, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007. As at February 21, 2006, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

In February 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.225 per common share. In May 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.24 per common share. In February 2004, the Board of Directors increased the annual dividend paid by the Company to $0.20 per common share, up from the previous level of $0.15 per common share.

In February 2006, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.30 per common share for 2006. The increase represents a 27% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the sixth consecutive year in which the Company has paid dividends and the fifth consecutive year of an increase in the distribution paid to its Shareholders.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. The Company has not entered into any contracts that would require consolidation under CICA Accounting Handbook, AcG-15, Consolidation of Variable Interest Entities. The following table summarizes the Company's commitments as at December 31, 2005:

($ millions)		2006		2007		2008		2009		2010		Thereafter
Product transportation and pipeline [1]	$	195	$	133	$	148	$	94	$	85	$	1,111
Offshore equipment operating lease	$	51	$	51	$	52	$	51	$	51	$	180
Offshore drilling	$	132	$	100	$	35	$	–	$	–	$	–
Asset retirement obligations [2]	$	82	$	4	$	4	$	4	$	7	$	3,224
Long-term debt [3]	$	–	$	161	$	36	$	36	$	–	$	2,966
Other [4]	$	61	$	62	$	21	$	29	$	23	$	8

(1) During the year, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.
(2) Represents management's estimate of the future payments to settle asset retirement obligations related to resource properties, facilities, production platforms and gathering systems, based on current legislation and industry operating practices.
(3) No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.
(4) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

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

RESERVES

For the year ended December 31, 2005, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved and probable crude oil, natural gas liquids ("NGL") and natural gas reserves [1] and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional assets. The Company has been granted an exemption from National Instrument 51-101 – Standards of Disclosure for 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. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of this Annual Report. The Company has elected to provide the net present value [2] of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as voluntary additional information, which is disclosed in the Company's most recent Annual Information Form.

Reserves and net present values presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices escalated at appropriate rates throughout the productive life of the properties.

For the year ended December 31, 2005, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Project and prepare an Evaluation Report on the Company's proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGL and natural gas reserves.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ 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 conventional crude oil, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

Additional reserve disclosure is contained in the supplementary oil and gas information of this Annual Report and the Company's most recent Annual Information Form.

(1) Conventional crude oil, NGL and natural gas includes all of the Company's light and medium, heavy, and thermal crude oil, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets.
(2) Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Only future development costs and associated material well abandonment liabilities have been applied with the exception of Offshore West Africa where all abandonment liabilities have been included.

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. These inherent risks include, but are not limited to, the following items:

- Economic risk of finding and producing reserves 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 and depletion rates.
- Pricing risk of marketing reserves at an acceptable price given current market conditions.
- 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.
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts.
- Interest rate risk associated with the Company's ability to secure financing at commercially acceptable terms.
- Foreign exchange risk due to fluctuating exchange rates, as the majority of sales are based in US dollars.
- Environmental impact risk associated with exploration and development activities.
- Risk of catastrophic loss due to fire, explosion or acts of nature.
- Other risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's international operations.

The Company uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses. Operational control is enhanced by focusing efforts on large core regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Refer to the "Risk management activities" section of this MD&A. In addition, the Company reviews 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.

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 most recent Annual Information Form.

ENVIRONMENT

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

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

- An annual 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 reduction and conservation program; and
- A program to replace the majority of fresh water for steaming with brackish water.

The Company has also established stringent operating standards in four areas:

- Using water-based, environmentally friendly drilling muds whenever possible;
- Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;
- Exercising care with respect to all waste produced through effective waste management plans; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2005, the Company's capital expenditures included $46 million for abandonment expenditures, an increase from $32 million in 2004 (2003 – $40 million).

Estimated asset retirement obligation, undiscounted ($ millions)	2005	2004
North America	$ 2,050	$ 1,770
North Sea	1,185	1,265
Offshore West Africa	90	25
	3,325	3,060
North Sea PRT recovery	(370)	(600)
	$ 2,955	$ 2,460

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with present legislation and industry operating practice. The future abandonment costs to be incurred by the Company in the North Sea will result in an estimated recovery of PRT of $370 million (2004 – $600 million, 2003 – $330 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $2,955 million (2004 – $2,460 million, 2003 – $1,950 million). The North Sea PRT recovery has decreased substantially from 2004 primarily due to improved economics related to the various fields, including a higher pricing environment and stronger Canadian dollar at December 31, 2005. Under these economic conditions, end of field losses at Tiffany previously assumed to be available for relief against PRT due from other fields is significantly reduced. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

KYOTO PROTOCOL

In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto"). The Company continues to work with the Federal and Provincial governments on the regulatory framework for greenhouse gases for larger emitters. The framework under development would see harmonized regulation between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2006 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008, which is the first year of the compliance period for the Kyoto Protocol.

The Company will continue to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company will work with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting Canada's competitive position.

Due to the high degree of cost uncertainty when the Federal Government ratified Kyoto, maximum per tonne cost assurances were agreed with large emitters for 2008 – 2012. Beyond 2012 investment concerns were addressed by the Federal Government as outlined in eight principles that would guide its negotiations and policies for this later stage.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the Company's financial position and operations. Actual results could differ from those estimates, and those differences could be material. 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.

PROPERTY, PLANT AND EQUIPMENT/DEPLETION, DEPRECIATION AND AMORTIZATION

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment. Accordingly, all costs relating to the exploration for and development of conventional 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country. Under Canadian GAAP, the capitalized costs and 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 dollar pricing as required by the SEC. 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 and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate.

The alternate acceptable method of accounting for crude oil and natural gas 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 higher DD&A rates compared to the successful efforts method.

CRUDE OIL AND NATURAL GAS RESERVES

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable crude oil and natural gas reserves. In 2005, 100% of the Company's reserves were evaluated by qualified independent reserves evaluators.

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, 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 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 reserve estimate would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

ASSET RETIREMENT OBLIGATION

Under CICA Handbook Section 3110, Asset Retirement Obligations ("ARO"), the Company is required to recognize a liability for the future retirement obligations associated with the Company's property, plant and equipment. An ARO is recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset the Company is required to settle as a result of 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 based on experience.

The estimated fair values of asset retirement obligations 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 asset retirement obligations 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 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 of 6.8%. In subsequent periods, the asset retirement obligation 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 capital cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the asset retirement obligation, timing of cash flows to settle the obligation and future inflation rates could result in gains or losses on the final settlement of the asset retirement obligations.

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

RISK MANAGEMENT ACTIVITIES

The Company utilizes various instruments to manage its commodity price and foreign currency exposures on revenue, and interest rate exposures on US dollar denominated debt. These derivative and financial instruments are not used for trading or speculative purposes.

On January 1, 2004, the Company prospectively adopted the Canadian Institute of Chartered Accountants' ("CICA") Accounting Guideline ("AcG") 13, "Hedging Relationships" and Emerging Issues Committee ("EIC") 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial instruments". Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded on the consolidated balance sheet as either an asset or liability with changes in fair value recognized in net earnings. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

PURCHASE PRICE ALLOCATIONS

The costs of corporate and asset acquisitions are allocated to the 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 amount 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 made 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 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 future price forecasts amongst 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

Based on their evaluation as of December 31, 2005, the Company's President and the Chief Financial Officer concluded, pursuant to Canadian Multilateral Instrument 52-109 Part 2.1, that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings is recorded, processed, summarized and reported within the time periods that meet the regulatory requirements. In addition, as of December 31, 2005, there were no changes in the Company's internal controls over financial reporting that occurred during 2005 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. The Company will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

NEW ACCOUNTING STANDARDS

In January 2005, the CICA issued four new standards relating to the recognition, measurement and disclosure of financial instruments.

- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This Section also specifies how financial instruments gains and losses are to be presented. Transitional provisions for this Section vary based on the type of financial instruments under consideration.

- Section 3865 – "Hedges" expands on existing AcG 13 – "Hedging Relationships", and Section 1650 "Foreign Currency Translation", by specifying how hedge accounting is to be applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

- Section 1530 – "Comprehensive Income" introduces new standards for reporting and disclosure of comprehensive income. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Financial statements of prior periods are required to be restated only for non-financial instrument items.

- Section 3251 – "Equity" replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods are required to be restated only for non-financial instrument items. For all other items, comparative financial statements presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required.

The Company plans to adopt these new standards effective January 1, 2007. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time as the financial derivatives outstanding at December 31, 2006 and their related fair values are not known.

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 high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of 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 2006 to average 1,468 mmcf/d to 1,551 mmcf/d of natural gas and 335,000 bbl/d to 373,000 bbl/d of crude oil and NGLs.

The budgeted capital expenditures in 2006 are currently expected to be as follows:

($ millions)	2006 Budget
North America natural gas	$ 1,741
North America crude oil and NGLs	1,097
North Sea	733
Offshore West Africa	187
Property acquisitions, dispositions and midstream	63
	3,821
Horizon Project Phase 1 Construction	2,561
Capitalized interest and other items	222
Horizon Project Phases 2/3 engineering	128
Canadian Natural Upgrader engineering	30
Total	$ 6,762

NORTH AMERICA NATURAL GAS

The 2006 North American natural gas program will be as follows:

(number of wells)	2006 Budget
Northeast British Columbia	262
Northwest Alberta	147
Northern Plains	251
Southern Plains	479
Total	1,139

Drilling will comprise both deep and conventional targets, with new production growth coming from the Company's Northeast British Columbia and Northwest Alberta areas.

NORTH AMERICA CRUDE OIL AND NGLS

The 2006 North America crude oil drilling program is highlighted by continued development of Primrose North thermal production and another strong conventional heavy program, as follows:

(number of wells)	2006 Budget
Conventional heavy crude oil	344
Thermal heavy crude oil	92
Light crude oil	111
Pelican Lake crude oil	150
Total	697

The Company continues the disciplined development of its heavy crude oil resources. Conventional heavy crude oil drilling is expected to increase, reflecting favourable crude oil prices and new opportunities identified in the property acquisitions made during 2004. Due to the nature of heavy crude oil production patterns, where production volumes ramp up during the first months of production, much of the production resulting from the expanded drill program will not be realized until late 2007.

In 2006, the Company expects to continue its Primrose thermal crude oil expansion plans. Activity in 2006 will be focused on the Primrose South expansion. Production from this project is subject to the cycling of steam injection and crude oil production and is expected to remain at similar levels to the 2005 production. The waterflood conversion project is on schedule with production response exceeding expectations. The Polymer Flood pilot project has yielded positive results to date and will continue in 2006.

THE HORIZON PROJECT

The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is expected to commence in the second half of 2008 at 110,000 bbl/d of 34° API light, sweet synthetic crude oil ("SCO"). The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure.

Construction costs for Phase 1 of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

Extensive front end design and the high degree of project definition have enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. The high degree of up front project engineering and pre-planning is expected to reduce the risks associated with scope changes.

NORTH SEA

The capital budget in 2006 for the North Sea is $733 million and includes the drilling of approximately 12 net platform wells on Ninian, Murchison and Tiffany. The Company will also conduct a mobile drilling program for which 6 subsea producer wells will be drilled at Columba E, Lyell, Toni and Thelma. Average crude oil production is expected to increase from 2005 production levels; however, natural gas volumes are expected to be flat as natural gas production at the Banff Field is diverted to reinjection.

OFFSHORE WEST AFRICA

In 2006, the capital budget for Offshore West Africa is set at $187 million, of which the Company anticipates $79 million to be spent on completing infill drilling at East Espoir and developing the West Espoir Field. West Espoir development is expected to yield first oil by mid-2006 at approximately 13,000 boe/d. Two additional wells will be completed at Baobab in 2006, allowing production to ramp to approximately 35,000 bbl/d net to the Company. $32 million will be expended on development of the Olowi Field offshore Gabon in 2006, with first oil expected late in 2008.

SENSITIVITY ANALYSIS [1]

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 2005. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	Cash flow from operations ($ millions)	Cash flow from operations ($/share, basic)	Net earnings ($ millions)	Net earnings ($/share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [2]				
Excluding financial derivatives	$ 113	$ 0.21	$ 79	$ 0.15
Including financial derivatives	$ 60	$ 0.11	$ 40	$ 0.07
Natural gas – AECO C$0.10/mcf [2]				
Excluding financial derivatives	$ 38	$ 0.07	$ 24	$ 0.05
Including financial derivatives	$ 14	$ 0.03	$ 8	$ 0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 104	$ 0.19	$ 53	$ 0.10
Natural gas – 10 mmcf/d	$ 32	$ 0.06	$ 17	$ 0.03
Foreign currency rate change				
$0.01 change in C$ in relation to US$ [2]	$ 82-84	$ 0.15-0.16	$ 32-33	$ 0.06
Interest rate change – 1%	$ 7	$ 0.01	$ 7	$ 0.01

(1) The sensitivities are calculated based on 2005 fourth quarter results excluding mark-to-market gains (losses) on risk management activities.
(2) For details of financial instruments in place, refer to note 10 to the Company's audited annual consolidated financial statements as at December 31, 2005.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES [1]

	Q1	Q2	Q3	Q4	2005	2004	2003
Crude oil and NGLs (bbl/d)							
North America	209,125	215,693	231,260	230,263	221,669	206,225	174,895
North Sea	71,139	62,884	73,543	66,798	68,593	64,706	56,869
Offshore West Africa	7,539	10,487	29,921	43,207	22,906	11,558	10,628
Total	287,803	289,064	334,724	340,268	313,168	282,489	242,392
Natural gas (mmcf/d)							
North America	1,430	1,434	1,400	1,402	1,416	1,330	1,245
North Sea	23	17	18	15	19	50	46
Offshore West Africa	2	3	5	6	4	8	8
Total	1,455	1,454	1,423	1,423	1,439	1,388	1,299
Barrels of oil equivalent (boe/d)							
North America	447,446	454,602	464,607	463,869	457,695	427,936	382,315
North Sea	74,956	65,751	76,545	69,361	71,651	73,093	64,469
Offshore West Africa	7,914	11,027	30,759	44,275	23,614	12,806	12,030
Total	530,316	531,380	571,911	577,505	552,960	513,835	458,814

(1) The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. For production where revenue has not yet been recognized, the related crude oil inventory volumes, by segment, were as follows at December 31, 2005:

(bbls)	2005
North America, related to Corsicana pipeline line fill	484,157
North Sea, related to timing of liftings	747,141
Offshore West Africa, related to timing of liftings, net of government entitlement to profit oil	412,841
	1,644,139

At December 31, 2004, variances between production volumes and liftings were not significant.

PER UNIT RESULTS [1]

	Q1	Q2	Q3	Q4	2005	2004	2003
Crude oil and NGLs ($/bbl)							
Sales price [2]	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86	$ 37.99	$ 32.66
Royalties	3.39	3.33	5.11	3.89	3.97	3.16	2.77
Production expense	11.30	11.66	11.48	10.33	11.17	10.05	10.28
Netback	$ 25.12	$ 27.52	$ 40.76	$ 32.16	$ 31.72	$ 24.78	$ 19.61
Natural gas ($/mcf)							
Sales price [2]	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57	$ 6.50	$ 6.21
Royalties	1.30	1.48	1.93	2.30	1.75	1.35	1.32
Production expense	0.69	0.71	0.76	0.76	0.73	0.67	0.60
Netback	$ 4.69	$ 5.14	$ 5.92	$ 8.61	$ 6.09	$ 4.48	$ 4.29
Barrels of oil equivalent ($/boe)							
Sales price [2]	$ 39.94	$ 43.05	$ 54.87	$ 56.08	$ 48.77	$ 38.45	$ 34.84
Royalties	5.42	5.85	7.84	8.01	6.82	5.37	5.20
Production expense	8.04	8.29	8.56	7.93	8.21	7.35	7.15
Netback	$ 26.48	$ 28.91	$ 38.47	$ 40.14	$ 33.74	$ 25.73	$ 22.49

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

NETBACK ANALYSIS

($/boe) [1]	2005	2004	2003
Sales price [2]	$ 48.77	$ 38.45	$ 34.84
Royalties	6.82	5.37	5.20
Production expense [3]	8.21	7.35	7.15
Netback	33.74	25.73	22.49
Midstream contribution [3]	(0.26)	(0.26)	(0.28)
Administration [4]	0.75	0.66	0.52
Interest, net	0.74	1.01	1.20
Realized risk management activities loss	5.13	2.52	1.09
Realized foreign exchange (gain) loss	(0.15)	0.02	0.05
Taxes other than income tax – current	1.01	1.12	0.69
Current income tax – North America	0.41	0.47	0.14
Current income tax – Large Corporations Tax	0.08	0.05	0.06
Current income tax – North Sea	0.77	0.01	0.26
Current income tax – Offshore West Africa	0.17	0.07	0.09
Current income tax – other	0.01	0.01	–
Cash flow	$ 25.08	$ 20.05	$ 18.67

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Including transportation costs and excluding risk management activities.
(3) Excluding inter-segment eliminations.
(4) Restated to conform to current year presentation.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2005 Total	2004 Total [1]
TSX – C$						
Trading volume (thousands)	169,018	155,274	160,121	153,579	637,992	606,024
Share price ($/share)						
High	$ 37.38	$ 46.98	$ 60.00	$ 62.00	$ 62.00	$ 27.58
Low	$ 24.28	$ 30.54	$ 45.52	$ 43.55	$ 24.28	$ 15.96
Close	$ 34.18	$ 44.40	$ 52.50	$ 57.63	$ 57.63	$ 25.63
Market capitalization at December 31 ($ millions)					$ 30,910	$ 13,744
Shares outstanding (thousands)					536,348	536,361
NYSE – US$						
Trading volume (thousands)	48,333	68,743	66,802	67,676	251,554	125,468
Share price ($/share)						
High	$ 30.37	$ 38.03	$ 50.73	$ 54.05	$ 54.05	$ 22.37
Low	$ 19.74	$ 24.49	$ 36.87	$ 36.65	$ 19.74	$ 11.94
Close	$ 28.41	$ 36.38	$ 45.19	$ 49.62	$ 49.62	$ 21.39
Market capitalization at December 31 ($ millions)					$ 26,614	$ 11,470
Shares outstanding (thousands)					536,348	536,361

(1) Restated to reflect two-for-one share split in May 2005.

Management's Report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. 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 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, 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 examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. 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. This committee, which is comprised of non-management directors, meets with management and the external 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 & Chief
Operating Officer
February 21, 2006

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

Randall S. Davis CA
Vice President, Financial
Accounting & Controls

Auditors' Report

TO THE SHAREHOLDERS OF CANADIAN NATURAL RESOURCES LIMITED,

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 21, 2006

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's consolidated financial statements, such as the change described in Note 10 to the consolidated financial statements. Our report to the shareholders dated February 21, 2006 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 21, 2006

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 18	$ 28
Accounts receivable and other	1,546	1,055
Future income tax (note 6)	487	83
Current portion of other long-term assets (note 2)	–	34
	2,051	1,200
Property, plant and equipment (note 3)	19,694	17,064
Other long-term assets (note 2)	107	108
	$ 21,852	$ 18,372
LIABILITIES		
Current liabilities		
Accounts payable	$ 573	$ 379
Accrued liabilities	1,781	1,019
Current portion of long-term debt (note 4)	–	194
Current portion of other long-term liabilities (note 5)	1,471	260
	3,825	1,852
Long-term debt (note 4)	3,321	3,538
Other long-term liabilities (note 5)	1,434	1,208
Future income tax (note 6)	5,035	4,450
	13,615	11,048
SHAREHOLDERS' EQUITY		
Share capital (note 7)	2,442	2,408
Retained earnings	5,804	4,922
Foreign currency translation adjustment (note 8)	(9)	(6)
	8,237	7,324
	$ 21,852	$ 18,372

Commitments (note 11)

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)	2005	2004	2003
Revenue	$ 10,107	$ 7,547	$ 6,155
Less: royalties	(1,366)	(1,011)	(872)
Revenue, net of royalties	8,741	6,536	5,283
Expenses			
Production	1,663	1,400	1,209
Transportation	270	250	262
Depletion, depreciation and amortization	2,013	1,769	1,509
Asset retirement obligation accretion (note 5)	69	51	62
Administration	151	125	87
Stock-based compensation (note 5)	723	249	200
Interest, net	149	189	201
Risk management activities (note 10)	1,952	434	148
Foreign exchange gain	(132)	(91)	(335)
	6,858	4,376	3,343
Earnings before taxes	1,883	2,160	1,940
Taxes other than income tax (note 6)	194	165	107
Current income tax (note 6)	286	116	92
Future income tax (note 6)	353	474	338
Net earnings	$ 1,050	$ 1,405	$ 1,403
Net earnings per common share (note 9)			
Basic	$ 1.96	$ 2.62	$ 2.62
Diluted	$ 1.95	$ 2.60	$ 2.53

Consolidated Statements of Retained Earnings

For the years ended December 31 (millions of Canadian dollars)	2005	2004	2003
Balance – beginning of year	$ 4,922	$ 3,650	$ 2,424
Net earnings	1,050	1,405	1,403
Dividends on common shares (note 7)	(127)	(107)	(81)
Purchase of common shares under Normal Course Issuer Bid (note 7)	(41)	(26)	(96)
Balance – end of year	$ 5,804	$ 4,922	$ 3,650

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	2005	2004	2003
Operating activities			
Net earnings	$ 1,050	$ 1,405	$ 1,403
Non-cash items			
Depletion, depreciation and amortization	2,013	1,769	1,509
Asset retirement obligation accretion	69	51	62
Stock-based compensation	723	249	200
Unrealized risk management activities	925	(40)	–
Unrealized foreign exchange gain	(103)	(94)	(343)
Deferred petroleum revenue tax recovery	(9)	(45)	(9)
Future income tax	353	474	338
Deferred charges	(31)	(33)	10
Abandonment expenditures	(46)	(32)	(40)
Net change in non-cash working capital (note 12)	(147)	(14)	(48)
	4,797	3,690	3,082
Financing activities			
(Repayment) issue of bank credit facilities	(435)	357	(647)
Issue (repayment) of medium-term notes	400	(125)	–
Repayment of senior unsecured notes	(194)	(54)	(85)
Repayment of preferred securities	(107)	–	–
Issue of US dollar debt securities	–	830	–
Repayment of obligations under capital leases	–	(7)	(8)
Dividends on common shares	(121)	(101)	(77)
Issue of common shares on exercise of stock options	9	24	89
Purchase of common shares	(45)	(33)	(144)
Net change in non-cash working capital (note 12)	19	6	(11)
	(474)	897	(883)
Investing activities			
Expenditures on property, plant and equipment	(5,340)	(4,582)	(2,486)
Net proceeds on sale of property, plant and equipment	454	7	20
Net expenditures on property, plant and equipment	(4,886)	(4,575)	(2,466)
Net proceeds on sale of other assets	11	–	–
Net change in non-cash working capital (note 12)	542	(88)	341
	(4,333)	(4,663)	(2,125)
(Decrease) increase in cash	(10)	(76)	74
Cash – beginning of year	28	104	30
Cash – end of year	$ 18	$ 28	$ 104

Supplemental disclosure of cash flow information (note 12)

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company head-quartered in Calgary, Alberta, Canada. The Company's operations are focused in North America, largely in western Canada, the United Kingdom portion of the North Sea and Offshore West Africa. Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US GAAP") is contained in note 15.

Significant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. A significant portion of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(B) MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Depletion, depreciation and amortization, and amounts used for ceiling test calculations are based on estimates of crude oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. Substantially all of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

The calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods could be material.

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of crude oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity of three months or less are reported as cash equivalents on the balance sheet.

(D) PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for crude oil and natural gas properties and equipment as prescribed 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. Administrative overhead incurred during the development phase of 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

Contractual arrangements that meet the definition of a lease as specified in Emerging Issues Committee ("EIC") 150 – "Determining Whether an Arrangement Contains a Lease" are accounted for as capital leases or operating leases as appropriate.

For mining activities, property acquisition, construction and development costs are capitalized. The Company reviews the recoverability of the carrying amount of its mining properties when events or circumstances indicate that the carrying amounts may not be recoverable.

(E) DEPLETION, DEPRECIATION AND AMORTIZATION

Costs related to each 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. Unproved properties are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs for major development projects are not subject to depletion until the projects are available for their intended uses. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its crude oil and natural gas 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 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 and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

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.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

(F) CAPITALIZED INTEREST

Beginning in 2005, following the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization will cease once construction is substantially complete and the Horizon Project is available for its intended use.

(G) DEFERRED CHARGES

Deferred charges primarily include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

(H) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms and gathering system 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 life of the asset. 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.

(I) 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 the foreign currency translation adjustment 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 items. Gains or losses on translation are included in the consolidated statement of earnings.

Gains or losses on the translation of long-term debt denominated in US dollars are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 8) for translation gains or losses for that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations.

(J) REVENUE RECOGNITION

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer and delivery has taken place. 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.

(K) TRANSPORTATION COSTS

Transportation costs incurred to transport crude oil and natural gas to customers are recorded as a separate cost in the consolidated statement of earnings.

(L) PRODUCTION SHARING CONTRACT

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSC"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover its share and the government's share of capital and operating costs carried by the Company. Profit revenues are allocated to the Company in accordance with its respective equity interest, after a portion has been allocated to the government. Cost recovery and profit revenues are reported as sales revenues. The government's share of revenues attributable to the Company's equity interest, except for income tax, is reported as a royalty expense in accordance with the PSCs.

(M) PETROLEUM REVENUE TAX

The Company accounts for the United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current reserves and anticipated sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(N) 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 on 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.

(O) STOCK-BASED COMPENSATION PLANS

The Company accounts for its stock-based compensation plans using the intrinsic value method. The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or 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. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. 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.

(P) RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all 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 enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements 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. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

Cross currency swap agreements 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. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

(Q) 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 included as a liability are used to purchase common shares at the average market price during the year. The dilutive effect of 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.

(R) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

FINANCIAL INSTRUMENTS

In January 2005, the CICA issued four new standards relating to the accounting for and disclosure of financial instruments.

- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This Section also specifies how financial instruments gains and losses are to be presented. Transitional provisions for this Section vary based on the type of financial instruments under consideration.

- Section 3865 – "Hedges" expands on existing Accounting Guideline 13 – "Hedging Relationships," and Section 1650 "Foreign Currency Translation," by specifying how hedge accounting is to be applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

- Section 1530 – "Comprehensive Income" introduces new standards for reporting and disclosure of comprehensive income. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Financial statements of prior periods are required to be restated only for non-financial instrument items.

- Section 3251 – "Equity" replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods are required to be restated only for non-financial instrument items. For all other items, comparative financial statements presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required.

The Company plans to adopt these new standards for interim and annual financial statements effective January 1, 2007. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time as the financial derivatives outstanding at December 31, 2006 and their related fair values are not known.

(S) COMPARATIVE FIGURES

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2005.

Common share data has been restated to reflect the two-for-one share split in May 2005.

2. OTHER LONG-TERM ASSETS

	2005	2004
Deferred charges	$ 107	$ 76
Risk management (note 10)	–	66
	107	142
Less: current portion	–	34
	$ 107	$ 108

3. PROPERTY, PLANT AND EQUIPMENT

	2005			2004		
	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation	Net
Crude oil and natural gas						
North America	$ 22,258	$ 7,948	$ 14,310	$ 19,750	$ 6,356	$ 13,394
North Sea	2,703	1,022	1,681	2,550	727	1,823
Offshore West Africa	1,547	294	1,253	1,091	190	901
Other	27	14	13	22	14	8
Horizon Project	2,169	–	2,169	672	–	672
Midstream	251	48	203	241	32	209
Head office	124	59	65	101	44	57
	$ 29,079	$ 9,385	$ 19,694	$ 24,427	$ 7,363	$ 17,064

During the year ended December 31, 2005, the Company capitalized administrative overhead of $41 million (2004 – $49 million, 2003 – $35 million) relating to exploration and development in the North Sea and Offshore West Africa and $236 million (2004 – $35 million, 2003 – $23 million) in North America, primarily related to the Horizon Project.

During the year ended December 31, 2005, the Company capitalized $72 million (2004 and 2003 – $nil) in construction period interest costs related to the Horizon Project.

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

	2005	2004
Crude oil and natural gas		
North America	$ 1,372	$ 1,028
North Sea	28	44
Offshore West Africa	182	528
Other	13	8
Horizon Project	2,169	672
	$ 3,764	$ 2,280

The Company has used the following estimated benchmark future prices ("escalated pricing") in its ceiling test prepared in accordance with Canadian GAAP, as at December 31, 2005:

	2006	2007	2008	2009	2010	Average annual change thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 60.81	$ 61.61	$ 54.60	$ 50.19	$ 47.76	1.5%
Hardisty Heavy 12° API (C$/bbl)	$ 37.07	$ 37.29	$ 34.23	$ 32.27	$ 31.15	1.6%
Edmonton Par (C$/bbl)	$ 70.07	$ 70.99	$ 62.73	$ 57.53	$ 54.65	1.5%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 58.81	$ 59.58	$ 52.54	$ 48.10	$ 45.64	1.5%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 11.59	$ 10.11	$ 8.50	$ 7.58	$ 7.32	1.5%
AECO (C$/mmbtu)	$ 11.58	$ 10.84	$ 8.95	$ 7.87	$ 7.57	1.5%
Huntingdon/Sumas (C$/mmbtu)	$ 11.34	$ 10.70	$ 8.81	$ 7.73	$ 7.43	1.5%

4. LONG-TERM DEBT

	2005	2004
Bank credit facilities		
Bankers' acceptances	$ 122	$ –
US dollar bankers' acceptances (2005 – US$nil, 2004 – US$471 million)	–	557
Medium-term notes		
7.40% unsecured debentures due March 1, 2007	125	125
4.95% unsecured debentures due June 1, 2015	400	–
Senior unsecured notes		
7.69% due December 19, 2005 (2005 – US$nil, 2004 – US$125 million)	–	194
Adjustable rate due May 27, 2009 (2005 – US$93 million, 2004 – US$93 million)	108	112
Preferred securities		
8.30% due June 25, 2011 (2005 – US$nil, 2004 – US$80 million)	–	96
US dollar debt securities		
6.70% due July 15, 2011 (2005 – US$400 million, 2004 – US$400 million)	467	482
5.45% due October 1, 2012 (2005 – US$350 million , 2004 – US$350 million)	408	421
4.90% due December 1, 2014 (2005 – US$350 million, 2004 – US$350 million)	408	421
7.20% due January 15, 2032 (2005 – US$400 million, 2004 – US$400 million)	467	482
6.45% due June 30, 2033 (2005 – US$350 million, 2004 – US$350 million)	408	421
5.85% due February 1, 2035 (2005 – US$350 million, 2004 – US$350 million)	408	421
	3,321	3,732
Less: current portion of long-term debt	–	194
	$ 3,321	$ 3,538

BANK CREDIT FACILITIES

As at December 31, 2005 the Company had in place unsecured syndicated bank credit facilities of $3,425 million, comprised of:

- a $100 million operating demand facility;
- a two-tranche revolving credit and term loan facility of $1,825 million; and
- a 5-year revolving and term loan facility of $1,500 million.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If not extended, the full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit and term loan facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. These facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2005, was 5.44% (2004 – 3.47%).

The Company also has a £15 million demand overdraft credit facility related to the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, as at December 31, 2005 letters of credit aggregating $24 million (2004 – $24 million) have been issued.

MEDIUM-TERM NOTES

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program.

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

SENIOR UNSECURED NOTES

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes. The 6.42% senior unsecured notes were repaid in May 2004.

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES

In June 2005, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest determined as at the date of issuance.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014 (note 10).

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2006	$ –
2007	$ 161
2008	$ 36
2009	$ 36
2010	$ –
Thereafter	$ 2,966

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

5. OTHER LONG-TERM LIABILITIES

	2005	2004
Asset retirement obligations	$ 1,112	$ 1,119
Stock-based compensation	891	323
Risk management (note 10)	885	26
Other	17	–
	2,905	1,468
Less: current portion	1,471	260
	$ 1,434	$ 1,208

ASSET RETIREMENT OBLIGATIONS

At December 31, 2005, the Company's total estimated undiscounted costs to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was approximately $3,325 million (2004 – $3,060 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 an average credit-adjusted risk-free interest rate of 6.8%. A reconciliation of the discounted asset retirement obligations is as follows:

	2005	2004
Asset retirement obligations		
Balance – beginning of year	$ 1,119	$ 897
Liabilities incurred	47	339
Liabilities settled	(46)	(32)
Asset retirement obligation accretion	69	51
Revision of estimates	(56)	(86)
Foreign exchange	(21)	(50)
Balance – end of year	$ 1,112	$ 1,119

The Company's pipelines have an indeterminant life and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the first year in which the lives of the assets are determinable.

STOCK-BASED COMPENSATION

The Company recognizes a liability for the 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.

	2005	2004
Stock-based compensation		
Balance – beginning of year	$ 323	$ 171
Stock-based compensation provision	723	249
Cash payment for options surrendered	(227)	(80)
Transferred to common shares	(29)	(38)
Capitalized to Horizon Project	101	21
Balance – end of year	891	323
Less: current portion of stock-based compensation	629	243
	$ 262	$ 80

6. TAXES

TAXES OTHER THAN INCOME TAX

	2005	2004	2003
Current petroleum revenue tax	$ 181	$ 190	$ 106
Deferred petroleum revenue tax recovery	(9)	(45)	(9)
Provincial capital taxes and surcharges	22	20	10
	$ 194	$ 165	$ 107

INCOME TAX

The provision for income tax is as follows:

	2005	2004	2003
Current income tax expense			
Current income tax – North America	$ 82	$ 89	$ 43
Large Corporations Tax – North America	16	11	16
Current income tax – North Sea	155	2	23
Current income tax – Offshore West Africa	32	13	10
Current income tax – other	1	1	–
	286	116	92
Future income tax expense	353	474	338
Income tax	$ 639	$ 590	$ 430

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:

	2005	2004	2003
Canadian statutory income tax rate	38.0%	39.3%	41.1%
Income tax provision at statutory rate	$ 716	$ 849	$ 797
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	309	221	285
Canadian resource allowance	(293)	(270)	(281)
Large Corporations Tax	16	11	16
Deductible UK petroleum revenue tax	(65)	(57)	(40)
Foreign tax rate differentials	(1)	(31)	20
Federal income tax rate reductions	–	–	(247)
Provincial income tax rate reductions	(19)	(66)	(31)
Non-taxable portion of foreign exchange	(15)	(36)	(103)
Attributed Canadian Royalty Income	(21)	(4)	4
Other	12	(27)	10
Income tax	$ 639	$ 590	$ 430

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

	2005	2004
Future income tax liabilities		
Property, plant and equipment	$ 3,960	$ 3,677
Timing of partnership items	1,646	1,254
Unrealized foreign exchange gain on long-term debt	112	102
Risk management activities	–	19
Other	31	43
Future income tax assets		
Asset retirement obligations	(384)	(418)
Capital loss carryforwards	(79)	(92)
Attributed Canadian Royalty Income	(75)	(54)
Stock-based compensation	(300)	(106)
Risk management activities	(304)	–
Deferred petroleum revenue tax	(59)	(58)
Future income tax liability	4,548	4,367
Less: future income tax asset	(487)	(83)
Net future income tax liability	$ 5,035	$ 4,450

A significant portion of North America's taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependent upon the nature and amount of capital expenditures incurred in Canada.

During 2005, the Government of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5%, effective July 1, 2005, resulting in a $19 million reduction in the Company's future income tax liability.

During 2004, the Government of Alberta enacted legislation to reduce its corporate income tax rate by 1.0% effective April 1, 2004, resulting in a $66 million reduction in the Company's future income tax liability.

During 2003, the Government of Alberta enacted legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. Also during 2003, the Canadian federal government enacted legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is being phased out and a deduction for actual crown royalties paid is being phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the federal resource income tax rate changes.

7. 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

	2005			2004		
Common shares	Numbers of shares (thousands)		Amount	Numbers of shares (thousands)		Amount
Balance – beginning of year	536,361	$	2,408	534,926	$	2,353
Issued upon exercise of stock options	837		9	3,182		24
Previously recognized liability on stock options exercised for common shares	–		29	–		38
Purchase of common shares under Normal Course Issuer Bid	(850)		(4)	(1,747)		(7)
Balance – end of year	536,348	$	2,442	536,361	$	2,408

SHARE SPLIT

The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. All common share and per common share amounts have been restated to retroactively reflect the share split.

NORMAL COURSE ISSUER BID

In January 2005, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,818,012 common shares or 5% of the outstanding common shares of the Company on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at December 31, 2005, the Company had purchased 850,000 common shares (2004 – 1,746,800 common shares) at an average price of $53.29 per common share (2004 – $19.00 per common share), for a total cost of $45 million (2004 – $33 million). Retained earnings was reduced by $41 million (2004 – $26 million), representing the excess of the purchase price of the common shares over their stated value.

On January 20, 2006, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007. As at February 21, 2006, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

DIVIDEND POLICY

The Company pays regular quarterly dividends in January, April, July and October of each year.

On February 21, 2006, the Board of Directors set the Company's regular quarterly dividend at $0.075 per common share (2005 – $0.059 per common share, 2004 – $0.050 per common share).

STOCK OPTIONS

The Option Plan provides for granting of stock options to employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally 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 permits the holder to purchase one common share of the Company at the stated exercise price.

In June 2003 the Company approved a modification to its Option Plan providing the stock option holder the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of surrender, multiplied by the number of common shares covered by the stock options surrendered, in lieu of receiving common shares. The modification to the Option Plan was accounted for prospectively.

For the year ended December 31, 2005, the Company recorded stock-based compensation expense of $723 million (2004 – $249 million, 2003 – $200 million). In 2005, $101 million was capitalized to the Horizon Project (2004 – $21 million, 2003 – $10 million). As at December 31, 2005, the total liability for expected cash settlements under the Option Plan was $891 million (2004 – $323 million), of which $629 million (2004 – $243 million) was included as a current liability. During the year ended December 31, 2005, cash payments of $227 million were made for 7,523,000 stock options surrendered (2004 – cash payments of $80 million for 7,562,000 stock options surrendered). The following table summarizes information relating to stock options outstanding at December 31, 2005 and 2004:

	2005			2004		
	Stock options (thousands)		Weighted average exercise price	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	32,522	$	12.37	35,578	$	9.86
Granted	7,959	$	32.51	9,722	$	17.95
Exercised for common shares	(837)	$	9.81	(3,182)	$	7.55
Surrendered for cash settlement	(7,523)	$	10.49	(7,562)	$	9.36
Forfeited	(1,611)	$	19.36	(2,034)	$	13.86
Outstanding – end of year	30,510	$	17.79	32,522	$	12.37
Exercisable – end of year	8,677	$	11.21	7,632	$	9.92

The range of exercise prices of stock options outstanding and exercisable at December 31, 2005 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
$7.85 – $9.99	8,794	1.41	$	9.63	4,835	$	9.54
$10.00 – $14.99	6,690	2.50	$	11.74	2,780	$	11.54
$15.00 – $19.99	6,234	3.53	$	17.07	883	$	17.05
$20.00 – $24.99	1,568	4.82	$	22.89	176	$	22.55
$25.00 – $29.99	4,301	4.18	$	26.26	3	$	26.26
$30.00 – $34.99	1,449	4.84	$	33.22	–	$	–
$40.00 – $44.99	201	5.45	$	40.25	–	$	–
$45.00 – $49.99	251	5.54	$	47.16	–	$	–
$50.00 – $54.99	600	5.72	$	54.43	–	$	–
$55.00 – $59.35	422	5.88	$	55.89	–	$	–
	30,510	3.02	$	17.79	8,677	$	11.21

8. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

		2005		2004
Balance – beginning of year	$	(6)	$	3
Unrealized loss on translation of net investment		(12)		(24)
Hedge of net investment with US dollar denominated debt, net of tax		9		15
Balance – end of year	$	(9)	$	(6)

9. NET EARNINGS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted amounts per common share:

	2005	2004[2]	2003[2]
(thousands of shares)			
Weighted average common shares outstanding – basic	536,650	536,223	536,940
Effect of dilutive stock options [1]	–	–	4,889
Assumed settlement of preferred securities with common shares	1,775	4,461	7,816
Weighted average common shares outstanding – diluted	538,425	540,684	549,645
Net earnings	$ 1,050	$ 1,405	$ 1,403
Interest on preferred securities, net of tax	4	5	5
Revaluation of preferred securities, net of tax	(2)	(4)	(18)
Diluted net earnings	$ 1,052	$ 1,406	$ 1,390
Net earnings per common share			
Basic	$ 1.96	$ 2.62	$ 2.62
Diluted	$ 1.95	$ 2.60	$ 2.53

(1) The Option Plan described in note 7 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 diluted earnings per share effective from June 2003, the date of the modification.
(2) Restated to reflect two-for-one share split in May 2005.

10. FINANCIAL INSTRUMENTS

RISK MANAGEMENT

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications.

As at December 31, 2005 and 2004, the estimated fair values of non-designated financial derivatives were comprised as follows:

	2005		2004	
	Risk management mark-to-market	Deferred revenue	Risk management mark-to-market	Deferred revenue
Balance – beginning of year	$ 66	$ (26)	$ 40	$ (40)
Net cost of put options outstanding as at December 31	190	–	38	–
Net change in fair value of financial instruments outstanding as at December 31	(943)	–	26	–
Amortization of deferred revenue	–	18	–	14
Balance – end of year	(687)	(8)	104	(26)
Less: put premium financing obligations	(190)	–	(38)	–
	(877)	(8)	66	(26)
Less: current portion [1]	834	8	34	17
	$ (43)	$ –	$ 32	$ (9)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective option.

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

	2005	2004	2003
Net realized risk management loss	$ 1,027	$ 474	$ 148
Net unrealized risk management loss (gain)	925	(40)	–
	$ 1,952	$ 434	$ 148

As at December 31, 2005, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $990 million (December 31, 2004 – net unrecognized asset of $33 million).

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities, risk management activities, stock-based compensation and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information, appropriate valuation methodologies and third party indications. However, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities, stock-based compensation and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments were as follows:

	2005		2004	
	Carrying value	Fair value	Carrying value	Fair value
Asset (liability)				
Derivative financial instruments	$ (687)	$ (1,700)	$ 66	$ 33
Fixed rate notes	$ (3,199)	$ (3,367)	$ (3,175)	$ (3,364)

COMMODITY PRICE RISK MANAGEMENT

The Company uses certain derivative financial instruments to manage its commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding as at December 31, 2005:

	Remaining term	Volume	Average price	Index
Crude oil				
Crude oil price collars	Jan 2006 – Dec 2006	167,644 bbl/d	US$38.26 – US$48.28	WTI
	Jan 2006 – Dec 2006	82,356 bbl/d	US$44.75 – US$76.93	WTI
	Jan 2006 – Dec 2006	22,000 bbl/d	C$46.53 – C$58.67	WTI
Crude oil puts (1)	Mar 2006 – Jul 2006	55,000 bbl/d	US$40.00	WTI
	Aug 2006 – Dec 2006	51,000 bbl/d	US$45.00	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$28.00	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$45.00	WTI
Brent differential swaps	Jan 2006 – Dec 2006	25,000 bbl/d	US$1.29	WTI/Dated Brent
	Jan 2007 – Dec 2007	50,000 bbl/d	US$1.34	WTI/Dated Brent

(1) Subsequent to year end, the Company settled 17,000 bbl/d of the US$40.00 put options for 2006 and purchased 100,000 bbl/d of US$50.00 put options for 2007.

	Remaining term	Volume	Average price	Index
Natural gas				
AECO collars	Jan 2006 – Mar 2006	700,000 GJ/d	C$5.88 – C$8.78	AECO
	Jan 2006 – Mar 2006	400,000 GJ/d	C$6.00 – C$12.29	AECO
	Jan 2006 – Mar 2006	100,000 GJ/d	C$8.00 – C$27.75	AECO
	Apr 2006 – Jun 2006	993,000 GJ/d	C$5.71 – C$8.13	AECO
	Apr 2006 – Jun 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Jul 2006 – Sep 2006	725,000 GJ/d	C$5.60 – C$7.59	AECO
	Jul 2006 – Sep 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Oct 2006 – Dec 2006	244,000 GJ/d	C$5.60 – C$7.59	AECO
	Oct 2006 – Dec 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Oct 2006 – Dec 2006	464,000 GJ/d	C$7.50 – C$18.80	AECO
	Jan 2007 – Mar 2007	700,000 GJ/d	C$7.50 – C$18.80	AECO

Commodity related derivative financial instruments designated as hedges at December 31, 2005, were all 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 agreements 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, 2005, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan 2006 – Jan 2007	US$200 (2)	7.20%	LIBOR (1) + 2.23%
	Jan 2006 – Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Jan 2006 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2006 – Mar 2007	C$6	7.36%	CDOR (3)

(1) London Interbank Offered Rate

(2) Subsequent to year end the Company received approximately $1 million in settlement of the 7.20% fixed to floating rate swap.

(3) Canadian Deposit Overnight Rate

Interest rate related derivative financial instruments designated as hedges at December 31, 2005, were all classified as fair value hedges.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign exchange rate risk in Canada on its US dollar denominated debt and on product sales based on US dollar denominated benchmarks. The Company is also exposed to foreign exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self sustaining foreign subsidiaries. Cross currency swap agreements 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. The Company may also enter into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations (note 8).

COUNTERPARTY CREDIT RISK MANAGEMENT

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 this risk by entering into sales contracts with only highly rated entities. In addition, the Company reviews 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. The Company is also 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 only highly rated financial institutions and other entities.

11. COMMITMENTS

The Company has committed to certain payments as follows:

	2006	2007	2008	2009	2010	Thereafter
Product transportation and pipeline (1)	$ 195	$ 133	$ 148	$ 94	$ 85	$ 1,111
Offshore equipment operating lease	$ 51	$ 51	$ 52	$ 51	$ 51	$ 180
Offshore drilling	$ 132	$ 100	$ 35	$ –	$ –	$ –
Asset retirement obligations (2)	$ 82	$ 4	$ 4	$ 4	$ 7	$ 3,224
Other (3)	$ 61	$ 62	$ 21	$ 29	$ 23	$ 8

(1) During the year, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, production platforms and pipelines, based on current legislation and industry operating practices.

(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

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

12. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2005	2004	2003
Decrease (increase) in non-cash working capital			
Accounts receivable and other	$ (498)	$ (329)	$ 35
Accounts payable	196	39	125
Accrued liabilities	716	194	122
Net change in non-cash working capital	$ 414	$ (96)	$ 282
Relating to:			
Operating activities	$ (147)	$ (14)	$ (48)
Financing activities	19	6	(11)
Investing activities	542	(88)	341
	$ 414	$ (96)	$ 282
Other cash flow information:			
Interest paid	$ 200	$ 192	$ 178
Taxes paid	$ 430	$ 218	$ 51

13. SEGMENTED INFORMATION

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

The Company's Horizon Project has been classified as a separate segment. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from crude oil and natural gas activities. There are currently no revenues for this project and all directly related expenditures have been capitalized.

Midstream activities include the Company's pipeline operations and an electricity co-generation system.

Activities that are not included in the above segments are included in the segmented information as other.

Inter-segment eliminations include internal transportation and electricity charges.

	Crude oil and natural gas								
	North America			North Sea			Offshore West Africa		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Segmented revenue	$ 7,932	$ 5,979	$ 5,021	$ 1,659	$ 1,317	$ 953	$ 485	$ 222	$ 155
Less: royalties	(1,350)	(1,003)	(868)	(3)	(2)	1	(13)	(6)	(5)
Revenue, net of royalties	6,582	4,976	4,153	1,656	1,315	954	472	216	150
Segmented expenses									
Production	1,211	976	845	379	370	314	53	36	38
Transportation	287	256	264	20	32	30	–	–	–
Depletion, depreciation and amortization	1,595	1,444	1,209	306	265	252	104	53	41
Asset retirement obligation accretion	34	28	26	34	22	36	1	1	–
Realized risk management activities	870	362	157	157	112	(9)	–	–	–
Total segmented expenses	3,997	3,066	2,501	896	801	623	158	90	79
Segmented earnings before the following	$ 2,585	$ 1,910	$ 1,652	$ 760	$ 514	$ 331	$ 314	$ 126	$ 71
Non-segmented expenses									
Administration									
Stock-based compensation									
Interest									
Unrealized risk management activities									
Foreign exchange gain									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax expense									
Future income tax expense									
Net earnings									

	Midstream			Inter-segment elimination and other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	$ 77	$ 68	$ 61	$ (46)	$ (39)	$ (35)	$10,107	$ 7,547	$ 6,155
	–	–	–	–	–	–	(1,366)	(1,011)	(872)
	77	68	61	(46)	(39)	(35)	8,741	6,536	5,283
	24	20	15	(4)	(2)	(3)	1,663	1,400	1,209
	–	–	–	(37)	(38)	(32)	270	250	262
	8	7	7	–	–	–	2,013	1,769	1,509
	–	–	–	–	–	–	69	51	62
	–	–	–	–	–	–	1,027	474	148
	32	27	22	(41)	(40)	(35)	5,042	3,944	3,190
	$ 45	$ 41	$ 39	$ (5)	$ 1	$ –	3,699	2,592	2,093
							151	125	87
							723	249	200
							149	189	201
							925	(40)	–
							(132)	(91)	(335)
							1,816	432	153
							1,883	2,160	1,940
							194	165	107
							286	116	92
							353	474	338
							$ 1,050	$ 1,405	$ 1,403

CAPITAL EXPENDITURES

	2005 Cash expenditures	2005 Non-cash and fair value adjustments (1)	2005 Capitalized costs	2004 Cash expenditures	2004 Non-cash and fair value adjustments (1)	2004 Capitalized costs
Crude oil and natural gas						
North America	$ 2,530	$ (22)	$ 2,508	$ 3,329	$ 508	$ 3,837
North Sea	387	(136)	251	608	172	780
Offshore West Africa	439	27	466	295	–	295
Other	5	–	5	1	–	1
	3,361	(131)	3,230	4,233	680	4,913
Horizon Project	1,499	–	1,499	291	–	291
Midstream	4	–	4	16	–	16
Head office	22	–	22	35	–	35
	$ 4,886	$ (131)	$ 4,755	$ 4,575	$ 680	$ 5,255

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.

Segmented property, plant and equipment, net	2005	2004
Crude oil and natural gas		
North America	$ 14,310	$ 13,394
North Sea	1,681	1,823
Offshore West Africa	1,253	901
Other	13	8
Horizon Project	2,169	672
Midstream	203	209
Head office	65	57
	$ 19,694	$ 17,064

Segmented assets	2005	2004
Crude oil and natural gas		
North America	$ 15,939	$ 14,390
North Sea	1,950	2,036
Offshore West Africa	1,371	914
Other	30	35
Horizon Project	2,239	672
Midstream	258	268
Head office	65	57
	$ 21,852	$ 18,372

14. BUSINESS COMBINATIONS

PETROVERA PARTNERSHIP

In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as the Petrovera Partnership ("Petrovera"), for $471 million.

The acquisition was accounted for based on the purchase method. Results from Petrovera are consolidated with the results of the Company effective from the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

	February 1, 2004
Purchase price:	
Cash consideration	$ 467
Cash acquired	(23)
Non-cash working capital deficit assumed	27
Total purchase price	$ 471
Purchase price allocated as follows:	
Property, plant and equipment	$ 643
Future income tax liability	(129)
Asset retirement obligation	(43)
	$ 471

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

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements are not addressed.

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

(millions of Canadian dollars, except per common share amounts)	Notes	2005	2004	2003
Net earnings – Canadian GAAP		$ 1,050	$ 1,405	$ 1,403
Adjustments				
Depletion, net of tax of $3 million (2004 – $2 million; 2003 – $3 million)	(A)	4	4	4
Derivative financial instruments and hedging activities, net of tax of $11 million (2004 – $7 million; 2003 – $20 million)	(B)	(19)	(9)	(49)
Capitalized interest, net of tax of $11 million	(C)	–	16	–
Cumulative effect of change in accounting policy, net of tax of $3 million	(D)	–	–	(4)
Net earnings – US GAAP		$ 1,035	$ 1,416	$ 1,354
Net earnings – US GAAP per common share				
Basic		$ 1.93	$ 2.64	$ 2.52
Diluted		$ 1.93	$ 2.62	$ 2.44

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2005	2004	2003
Net earnings – US GAAP		$ 1,035	$ 1,416	$ 1,354
Derivative financial instruments and hedging activities, net of tax of $312 million (2004 – $3 million; 2003 – $9 million)	(B)	(635)	8	20
Foreign currency translation adjustment	(E)	(3)	(9)	(23)
Comprehensive income		$ 397	$ 1,415	$ 1,351

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

		2005		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (decrease)	US GAAP
Current assets	(B)	$ 2,051	$ 338	$ 2,389
Property, plant and equipment	(A,C)	19,694	(20)	19,674
Other long-term assets		107	–	107
		$ 21,852	$ 318	$ 22,170
Current liabilities	(B)	$ 3,825	$ 1,005	$ 4,830
Long-term debt	(B)	3,321	(18)	3,303
Other long-term liabilities	(B)	1,434	8	1,442
Future income tax	(A,B,C)	5,035	(5)	5,030
Shareholders' equity	(B,E)	8,237	(672)	7,565
		$ 21,852	$ 318	$ 22,170

		2004		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (decrease)	US GAAP
Current assets	(B)	$ 1,200	$ (33)	$ 1,167
Property, plant and equipment	(A,C)	17,064	(27)	17,037
Other long-term assets		108	–	108
		$ 18,372	$ (60)	$ 18,312
Current liabilities	(B)	$ 1,852	$ (44)	$ 1,808
Long-term debt		3,538	–	3,538
Other long-term liabilities		1,208	–	1,208
Future income tax	(A,B,C)	4,450	6	4,456
Shareholders' equity	(B,E)	7,324	(22)	7,302
		$ 18,372	$ (60)	$ 18,312

NOTES:

(A) Under Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes, are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (the "ceiling test"). 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 and costs as at the balance sheet date ("constant dollar pricing") and are discounted at 10%.

(B) The Company accounts for its derivative financial instruments under Canadian GAAP as described in note 1(P). For US GAAP purposes, Financial Accounting Standards Board Statement ("FAS") 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149, establishes US GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness of cash flow hedges is based on a combination of third party indications and internally derived valuations. The Company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

(C) 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 has been capitalized to the costs of construction beginning in 2004.

(D) Under Canadian GAAP, when the asset retirement obligation standard was adopted prior period comparative balances were restated to reflect the effect of the new standard on that year. Under US GAAP, when the asset retirement obligation standard was adopted the cumulative effect of the new standard on prior periods was included in earnings in the year adopted.

(E) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

(F) Recently issued accounting standards under US GAAP:

SHARE-BASED PAYMENT

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS 123(R) "Share-Based Payment," which is a revision of FAS 123. This standard requires all companies to reflect stock based compensation in their statement of earnings for US GAAP. The fair value of stock options must be recognized at the date of grant using option pricing models. The fair value must be remeasured each quarter and changes in fair value must flow through the statement of earnings. This is a difference from Canadian GAAP, where the Company's options are valued at the difference between the exercise price and the stock price. This standard is effective for the first interim or annual reporting period of a registrant's first fiscal year beginning on or after June 15, 2005. The Company plans to adopt this standard January 1, 2006.

ACCOUNTING CHANGES AND ERROR CORRECTIONS

In May 2005, the FASB issued FAS 154 "Accounting Changes and Error Corrections," which replaces FAS 3 "Reporting Accounting Changes in Interim Financial Statements" and APB Opinion 20 "Accounting Changes." The previous standards required that changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. The new standard requires that accounting changes be applied retrospectively and that prior accounting periods be restated as if the accounting principle had always been used. This change eliminates a difference from Canadian GAAP. The new standard will be applied to all future US GAAP accounting policy changes.

Supplementary Oil & Gas Information (unaudited)

This supplementary oil and natural gas information is provided in accordance with the United States FAS 69, "Disclosures about Oil and Gas Producing Activities", and where applicable is reconciled to the US GAAP financial information.

NET PROVED OIL AND NATURAL GAS RESERVES

The Company retains qualified independent reserves evaluators to evaluate the Company's proved oil and natural gas reserves.

- For the year ended December 31, 2005, the reports by Sproule Associates Limited ("Sproule") and Ryder Scott Company covered 100% of the Company's conventional reserves;
- For the year ended December 31, 2004, the reports by Sproule and Ryder Scott Company covered 100% of the Company's conventional reserves;
- For the year ended December 31, 2003, the reports by Sproule covered 100% of the Company's conventional reserves; and
- For the year ended December 31, 2002, the reports by Sproule covered 89% of the Company's conventional reserves.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of 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 conventional crude oil and natural gas reserves, net of royalties, as at December 31, 2005, 2004 and 2003:

Crude oil and NGLs (mmbbl)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2002	571	202	75	848
Extensions and discoveries	1	–	13	14
Improved recovery	63	–	–	63
Purchases of reserves in place	7	27	–	34
Sales of reserves in place	–	–	–	–
Production	(56)	(21)	(4)	(81)
Revisions of previous estimates	2	14	1	17
Reserves, December 31, 2003	588	222	85	895
Extensions and discoveries	17	–	–	17
Improved recovery	25	45	–	70
Purchases of reserves in place	36	38	–	74
Sales of reserves in place	–	–	–	–
Production	(66)	(24)	(4)	(94)
Revisions of previous estimates	48	22	34	104
Reserves, December 31, 2004	648	303	115	1,066
Extensions and discoveries	98	–	–	98
Improved recovery	3	3	2	8
Purchases of reserves in place	–	–	15	15
Sales of reserves in place	(3)	–	–	(3)
Production	(70)	(25)	(8)	(103)
Revisions of previous estimates	18	9	10	37
Reserves, December 31, 2005	694	290	134	1,118
Net proved developed reserves:				
December 31, 2002	340	107	27	474
December 31, 2003	348	138	23	509
December 31, 2004	367	218	20	605
December 31, 2005	402	214	80	696

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2002	2,446	71	71	2,588
Extensions and discoveries	58	–	6	64
Improved recovery	251	–	–	251
Purchases of reserves in place	50	19	–	69
Sales of reserves in place	(3)	–	–	(3)
Production	(355)	(17)	(3)	(375)
Revisions of previous estimates	(21)	(11)	(10)	(42)
Reserves, December 31, 2003	2,426	62	64	2,552
Extensions and discoveries	334	–	–	334
Improved recovery	80	–	–	80
Purchases of reserves in place	182	10	–	192
Sales of reserves in place	(8)	–	–	(8)
Production	(383)	(18)	(3)	(404)
Revision of previous estimates	(40)	(27)	11	(56)
Reserves, December 31, 2004	2,591	27	72	2,690
Extensions and discoveries	506	–	–	506
Improved recovery	30	–	–	30
Purchases of reserves in place	6	–	–	6
Sales of reserves in place	(23)	–	–	(23)
Production	(411)	(7)	(1)	(419)
Revision of previous estimates	42	9	1	52
Reserves, December 31, 2005	2,741	29	72	2,842
Net proved developed reserves:				
December 31, 2002	2,185	57	27	2,269
December 31, 2003	2,140	46	12	2,198
December 31, 2004	2,213	12	5	2,230
December 31, 2005	2,300	16	10	2,326

CAPITALIZED COSTS RELATED TO OIL AND NATURAL GAS ACTIVITIES

	2005				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 20,886	$ 2,675	$ 1,365	$ 14	$ 24,940
Unproved properties	1,372	28	182	13	1,595
	22,258	2,703	1,547	27	26,535
Less: accumulated depletion and depreciation	(7,993)	(1,022)	(294)	(14)	(9,323)
Net capitalized costs	$ 14,265	$ 1,681	$ 1,253	$ 13	$ 17,212

	2004				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 18,749	$ 2,506	$ 563	$ 14	$ 21,832
Unproved properties	1,028	44	528	8	1,608
	19,777	2,550	1,091	22	23,440
Less: accumulated depletion and depreciation	(6,410)	(727)	(190)	(14)	(7,341)
Net capitalized costs	$ 13,367	$ 1,823	$ 901	$ 8	$ 16,099

	2003				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 15,125	$ 1,905	$ 566	$ 14	$ 17,610
Unproved properties	789	56	231	6	1,082
	15,914	1,961	797	20	18,692
Less: accumulated depletion and depreciation	(4,984)	(522)	(140)	(12)	(5,658)
Net capitalized costs	$ 10,930	$ 1,439	$ 657	$ 8	$ 13,034

COSTS INCURRED IN OIL AND NATURAL GAS ACTIVITIES

	2005				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ (448)	$ (3)	$ 63	$ –	$ (388)
Unproved	210	–	(52)	–	158
Exploration	360	22	16	5	403
Development	2,288	368	412	–	3,068
Finding and development costs	2,410	387	439	5	3,241
Asset retirement costs	98	(136)	27	–	(11)
Actual retirement expenditures	(46)	–	–	–	(46)
Costs incurred	$ 2,462	$ 251	$ 466	$ 5	$ 3,184

	2004				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 1,748	$ 302	$ –	$ –	$ 2,050
Unproved	298	4	–	–	302
Exploration	290	11	35	2	338
Development	1,403	308	259	–	1,970
Finding and development costs	3,739	625	294	2	4,660
Asset retirement costs	98	165	(10)	–	253
Actual retirement expenditures	(32)	–	–	–	(32)
Costs incurred	$ 3,805	$ 790	$ 284	$ 2	$ 4,881

	2003				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 236	$ 100	$ –	$ –	$ 336
Unproved	116	23	–	–	139
Exploration	190	41	27	7	265
Development	1,227	193	148	–	1,568
Finding and development costs	1,769	357	175	7	2,308
Asset retirement costs	80	59	9	–	148
Actual retirement expenditures	(30)	(1)	(9)	–	(40)
Costs incurred	$ 1,819	$ 415	$ 175	$ 7	$ 2,416

RESULTS OF OPERATIONS FROM OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from oil and natural gas producing activities for the years ended December 31, 2005, 2004 and 2003 are summarized in the following tables:

	2005			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 5,727	$ 1,499	$ 472	$ 7,698
Production	(1,211)	(379)	(53)	(1,643)
Transportation	(287)	(20)	–	(307)
Depletion, depreciation and amortization	(1,588)	(306)	(104)	(1,998)
Asset retirement obligation accretion	(34)	(34)	(1)	(69)
Petroleum revenue tax	–	(172)	–	(172)
Income tax	(1,007)	(235)	(110)	(1,352)
Results of operations	$ 1,600	$ 353	$ 204	$ 2,157

	2004			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 4,579	$ 1,203	$ 216	$ 5,998
Production	(976)	(370)	(36)	(1,382)
Transportation	(256)	(32)	–	(288)
Depletion, depreciation and amortization	(1,438)	(265)	(53)	(1,756)
Asset retirement obligation accretion	(28)	(22)	(1)	(51)
Petroleum revenue tax	–	(145)	–	(145)
Income tax	(690)	(148)	(44)	(882)
Results of operations	$ 1,191	$ 221	$ 82	$ 1,494

	2003			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 3,961	$ 962	$ 150	$ 5,073
Production	(845)	(314)	(38)	(1,197)
Transportation	(263)	(30)	(1)	(294)
Depletion, depreciation and amortization	(1,203)	(250)	(42)	(1,495)
Asset retirement obligation accretion	(23)	(39)	(1)	(63)
Petroleum revenue tax	–	(97)	–	(97)
Income tax	(673)	(93)	(24)	(790)
Results of operations	$ 954	$ 139	$ 44	$ 1,137

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

The following standardized measure of discounted future net cash flows from proved oil and natural gas reserves has been computed using year-end sales prices and costs 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 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 potential reserves;
- Future production of oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end sales prices and costs 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 site restoration costs 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 oil and natural gas reserves based on the standardized measure as prescribed in FAS 69:

	2005			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 52,266	$ 19,961	$ 8,515	$ 80,742
Future production costs	(17,310)	(6,130)	(1,803)	(25,243)
Future development and site restoration costs	(3,916)	(3,099)	(1,032)	(8,047)
Future income taxes	(10,272)	(6,631)	(2,092)	(18,995)
Future net cash flows	20,768	4,101	3,588	28,457
10% annual discount for timing of future cash flows	(7,793)	(1,144)	(1,068)	(10,005)
Standardized measure of future net cash flows	$ 12,975	$ 2,957	$ 2,520	$ 18,452

	2004			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 31,727	$ 15,526	$ 5,249	$ 52,502
Future production costs	(10,995)	(6,302)	(1,137)	(18,434)
Future development and site restoration costs	(2,944)	(2,832)	(631)	(6,407)
Future income taxes	(6,438)	(3,783)	(1,242)	(11,463)
Future net cash flows	11,350	2,609	2,239	16,198
10% annual discount for timing of future cash flows	(4,385)	(691)	(634)	(5,710)
Standardized measure of future net cash flows	$ 6,965	$ 1,918	$ 1,605	$ 10,488

	2003			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 32,720	$ 9,099	$ 3,192	$ 45,011
Future production costs	(9,480)	(3,015)	(1,179)	(13,674)
Future development and site restoration costs	(2,393)	(1,749)	(697)	(4,839)
Future income taxes	(7,295)	(2,801)	–	(10,096)
Future net cash flows	13,552	1,534	1,316	16,402
10% annual discount for timing of future cash flows	(6,203)	(336)	(432)	(6,971)
Standardized measure of future net cash flows	$ 7,349	$ 1,198	$ 884	$ 9,431

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)	2005	2004	2003
Sales of oil and natural gas produced, net of production costs	$ (5,785)	$ (4,331)	$ (3,582)
Net changes in sales prices and production costs	11,056	(553)	(2,750)
Extensions, discoveries and improved recovery	3,596	2,120	1,360
Changes in estimated future development costs	(971)	(894)	(346)
Purchases of proved reserves in place	469	1,386	594
Sales of proved reserves in place	(130)	(20)	(8)
Revisions of previous reserve estimates	961	1,431	144
Accretion of discount	1,812	1,558	2,000
Changes in production timing and other	1,414	1,357	(1,411)
Net change in income taxes	(4,458)	(997)	426
Net change	7,964	1,057	(3,573)
Balance – beginning of year	10,488	9,431	13,004
Balance – end of year	$ 18,452	$ 10,488	$ 9,431

Ten-Year Review

Years ended December 31	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
FINANCIAL INFORMATION										
(C$ millions, except per share amounts)										
Net earnings	1,050	1,405	1,403	539	639	758	213	31	104	88
Per share – basic [1]	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$ 0.51	$ 0.08	$ 0.26	$ 0.27
Cash flow from operations [2]	5,021	3,769	3,160	2,254	1,920	1,884	724	444	503	360
Per share – basic [1]	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$ 1.74	$ 1.12	$ 1.28	$ 1.08
Capital expenditures, net of dispositions (including business combinations)	4,932	4,633	2,506	4,069	1,885	2,823	1,901	610	1,119	1,204
Balance Sheet information										
Working capital (deficiency) surplus	(1,774)	(652)	(505)	(14)	(6)	(77)	36	58	(19)	(1)
Property, plant and equipment, net	19,694	17,064	13,714	12,934	8,766	7,439	4,679	3,135	2,831	1,993
Total assets	21,852	18,372	14,643	13,793	9,290	8,051	4,976	3,329	3,016	2,144
Long-term debt	3,321	3,538	2,748	4,200	2,788	2,573	2,157	1,426	1,136	588
Shareholders' equity	8,237	7,324	6,006	4,754	3,928	3,297	1,962	1,317	1,250	1,108
SHARE INFORMATION										
Common shares outstanding (thousands)	536,348	536,361	534,926	535,104	484,804	489,116	445,816	399,236	395,276	389,532
Weighted average shares outstanding (thousands)	536,650	536,223	536,940	511,532	485,200	466,804	415,624	397,324	392,168	332,984
Dividends declared per common share	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ –	$ –	$ –	$ –	$ –
Trading statistics [1]										
TSX – C$										
Trading volume (thousands)	637,992	606,024	590,702	619,316	534,976	567,412	430,460	410,440	402,152	396,888
Share Price ($/share)										
High	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$ 9.65	$ 7.88	$ 11.06	$ 9.85
Low	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$ 4.95	$ 4.56	$ 7.23	$ 4.81
Close	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$ 8.81	$ 5.75	$ 7.65	$ 9.40
NYSE – US$										
Trading volume (thousands)	251,554	125,468	46,916	31,864	20,764	3,172	–	–	–	–
Share Price ($/share)										
High	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$ –	$ –	$ –	$ –
Low	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$ –	$ –	$ –	$ –
Close	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$ –	$ –	$ –	$ –
RATIOS										
Debt to cash flow [3]	0.7x	1.0x	0.9x	1.9x	1.5x	1.4x	3.0x	3.2x	2.3x	1.6x
Debt to book capitalization [3]	28.7%	33.8%	32.8%	47.1%	41.7%	44.0%	52.4%	52.0%	47.6%	34.7%
Return on average common shareholders' equity, after tax [3]	14.3%	21.4%	25.6%	13.0%	17.7%	28.8%	13.0%	2.4%	8.8%	10.9%
Debt to EBITDA [3]	0.6x	0.9x	0.8x	1.7x	1.4x	1.2x	2.6x	2.9x	4.8x	3.0x
Daily production before royalties per ten thousand common shares (boe/d)	10.3	9.6	8.5	8.2	7.4	6.6	5.0	4.7	4.5	3.6
Conventional proved and probable reserves per common share (boe) [4]	4.8	4.3	4.0	3.3	3.1	2.9	2.4	1.9	1.7	1.3
Net asset value per common share [1][5]	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54	$ 12.33	$ 8.08	$ 6.80	$ 6.46

(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.
(2) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on earnings and cash flow. Cash flow from operations may not be comparable to similar measures used by other companies.
(3) Refer to the MD&A, page 62, "Liquidity and Capital Resources", for the definitions of these items.
(4) Based upon constant dollar Company gross reserves (before royalties), using year-end common shares outstanding.
(5) Based upon 10% discounted, forcast price pre-tax proved and probable net present values as reported in the Company's AIF for conventional reserves, with $250/acre added for core undeveloped land in 2005 and $75/acre for all years prior, less long-term debt and existing asset liabilities and adjusted for working capital. See reserves disclosures on pages 40 to 44.

Years ended December 31	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
OPERATING INFORMATION										
Conventional crude oil and NGLs (mmbbl)										
Company gross proved reserves (before royalties)										
North America	785	695	672	665	644	643	554	284	257	136
North Sea	290	303	222	203	83	102	–	–	–	–
Offshore West Africa	148	125	106	94	61	36	–	–	–	–
	1,223	1,123	1,000	962	788	781	554	284	257	136
Company gross proved and probable reserves (before royalties)										
North America	1,154	992	977	742	740	731	640	380	329	185
North Sea	417	415	317	277	106	134	–	–	–	–
Offshore West Africa	230	214	187	162	111	46	–	–	–	–
	1,801	1,621	1,481	1,181	957	911	640	380	329	185
Conventional natural gas (bcf)										
Company gross proved reserves (before royalties)										
North America	3,378	3,202	3,006	3,048	2,566	2,360	2,183	1,901	1,716	1,566
North Sea	29	27	62	71	94	91	–	–	–	–
Offshore West Africa	83	81	86	90	69	65	–	–	–	–
	3,490	3,310	3,154	3,209	2,729	2,516	2,183	1,901	1,716	1,566
Company gross proved and probable reserves (before royalties)										
North America	4,372	4,100	3,611	3,450	2,915	2,762	2,547	2,211	2,078	1,926
North Sea	69	57	101	89	118	114	–	–	–	–
Offshore West Africa	127	102	111	120	96	84	–	–	–	–
	4,568	4,259	3,823	3,659	3,129	2,960	2,547	2,211	2,078	1,926
Total proved reserves (before royalties) (mmboe)	1,804	1,674	1,526	1,497	1,243	1,200	918	601	543	397
Total proved and probable reserves (before royalties) (mmboe)	2,562	2,330	2,118	1,791	1,479	1,404	1,065	749	675	506
Oil sands, mining (mmbbl)										
Gross proved and probable reserves (before royalties)										
Bitumen	3,430	–	–	–	–	–	–	–	–	–
Synthetic crude oil *	2,878	–	–	–	–	–	–	–	–	–
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America	222	206	175	169	167	155	87	76	71	37
North Sea	68	65	57	39	36	17	–	–	–	–
Offshore West Africa	23	12	10	7	3	2	–	–	–	–
	313	283	242	215	206	174	87	76	71	37
Natural gas (mmcf/d)										
North America	1,416	1,330	1,245	1,204	906	793	721	673	626	499
North Sea	19	50	46	27	12	1	–	–	–	–
Offshore West Africa	4	8	8	1	–	–	–	–	–	–
	1,439	1,388	1,299	1,232	918	794	721	673	626	499
Total production (before royalties) (mboe/d)	553	514	459	421	359	306	207	188	175	120
Product pricing										
Average crude oil and NGLs price ($/bbl)	46.86	37.99	32.66	31.22	23.45	31.89	22.26	11.98	18.99	24.73
Average natural gas price ($/mcf)	8.57	6.50	6.21	3.77	5.45	4.92	2.52	2.11	1.97	1.67

* SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

Corporate information

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

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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.

Toronto Stock Exchange ("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 and material revisions to such plans. Canadian Natural follows TSX rules with respect to shareholder approval of equity compensation plans.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2005 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying the quality of its public disclosure.

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario
Computershare Investor Services LLC
New York, New York

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Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants
Calgary, Alberta

Ryder Scott Company
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange
CNQ
CNQ.U (Denotes trading in US funds)
The New York Stock Exchange
CNQ

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Canadian Natural

IMPORTANT DATES

PRESS RELEASE FIRST QUARTER 2006
Thursday, May 4, 2006

ANNUAL GENERAL MEETING
Thursday, May 4, 2006

PRESS RELEASE SECOND QUARTER 2006
Wednesday, August 2, 2006

PRESS RELEASE THIRD QUARTER 2006
Wednesday, November 1, 2006

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You can request documents by calling our head office or via email: **ir@cnrl.com**

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