C A N A D I A N N A T U R A L R E S O U R C E S L I M I T E D

ANNUAL INFORMATION FORM

April 22, 2002

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CURRENCY

Unless otherwise indicated, all dollar figures stated in this Annual Information Form represent Canadian dollars.

DEFINITIONS

The following are definitions of certain abbreviations used in this Annual Information Form:

"**ARTC**" means Alberta Royalty Tax Credit.

"**bbl**" or "**barrel**" means 34.972 Imperial gallons or 42 U.S. gallons.

"**Bcf**" means one billion cubic feet.

"**Bpd**" means barrels per day.

"Canadian Natural Resources Limited", **"CNRL"** or **"Company"** means Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries.

"FPSO" means floating production, storage and off-take vessel.

"**gross acres**" means the total number of acres in which the Company holds a working interest or the right to earn a working interest.

"**gross wells**" means the total number of wells in which the Company has a working interest.

"**Mbbls**" means one thousand barrels.

"**Mcf**" means one thousand cubic feet.

"**Mcfd**" means one thousand cubic feet per day.

"MMbbls" means one million barrels.

"**MMbtu**" means one million British thermal units

"**MMcf**" means one million cubic feet.

"**MMcfd**" means one million cubic feet per day.

"**NGLs**" means natural gas liquids.

"**net acres**" refers to gross acres multiplied by the percentage working interest therein owned or to be owned by the Company.

"**net wells**" refers to gross wells multiplied by the percentage working interest therein owned or to be owned by the Company.

"SAGD" means steam -assisted gravity drainage.

"**undeveloped land**" or "**non-reserve acreage**" refers to lands on which wells have not been drilled nor completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

"**working interest**" means the interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens.

"WTI" means West Texas Intermediate.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or incorporated herein by reference may constitute "forward-looking statements" within the meaning of the United States Private 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 the Company "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 which 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, insurgent groups or other conflict including conflict between states; industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the ability of the Company to complete its capital programs; the 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 availability and cost of financing; the success of exploration and development activities; 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); site restoration costs; 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 upon other factors, and management'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 are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

THE COMPANY

Canadian Natural Resources Limited was incorporated under the laws of the Province of British Columbia on November 7, 1973 as AEX Minerals Corporation (N.P.L.) and on December 5, 1975 changed its name to Canadian Natural Resources Limited. CNRL was continued under *The Companies Act of Alberta* on January 6, 1982 and was further continued under the *Business Corporations Act* (Alberta) on November 6, 1985. The head, principal and registered office of the Company is located in Calgary, Alberta, Canada at 2500, 855–2nd Street S.W., T2P 4J8.

CNRL formed a wholly owned subsidiary, CanNat Resources Inc. ("CanNat") in January 1995. Pursuant to a Plan of Arrangement the Company acquired all of the outstanding shares of Sceptre Resources Limited ("Sceptre") in September 1996 and in January 1997, Sceptre and CanNat amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name CanNat Resources Inc.

Pursuant to an Offer to Purchase all of the outstanding shares, the Company completed the acquisition of Ranger Oil Limited, including its subsidiaries, ("Ranger") in July 2000. On October 1, 2000 Ranger Oil Limited and the Company amalgamated under the name Canadian Natural Resources Limited.

The material operating subsidiaries of the Company, each of which is directly or indirectly wholly-owned, and their jurisdiction of incorporation are as follows:

Name of Company	Jurisdiction of Incorporation
CanNat Resources Inc.	Alberta
CNR International (U. K.) Developments Limited	England
CNR International (U. K.) Limited	England
Ranger Oil Côte d'Ivoire SARL	Côte d'Ivoire

CNRL as the managing partner and CanNat are the partners of Canadian Natural Resources (the "Partnership"). The Partnership is a general partnership, which holds Canadian crude oil and natural gas properties. CNRL also has a 15% interest in Cold Lake Pipeline Ltd., which is the General Partner of Cold Lake Pipeline Limited Partnership of which CNRL has a 14.7% interest.

The consolidated financial statements of CNRL include the accounts of the Company and all of its subsidiaries and partnerships.

GENERAL DEVELOPMENT OF THE BUSINESS

CNRL's business is the acquisition of interests in crude oil and natural gas rights and the exploration, development, production, marketing and sale of crude oil and natural gas.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. CNRL's objective is to grow its cash flow and earnings through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company’s principal areas of crude oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom (the “UK”) sector of the North Sea and offshore West Africa. The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2001 the Company had 1,186 full time employees.

In the third quarter of 1999 the Company acquired the remaining assets held by the crude oil business unit of BP Amoco for an acquisition price of $1.1 billion. These assets were comprised of crude oil producing properties including related facilities, undeveloped lands, an 85-megawatt co-generation plant and gross overriding royalties. The Company also acquired through a plan of arrangement proposed by the Company under the *Companies Creditors' Arrangement Act* (Canada), all of the crude oil and natural gas properties and related assets held by Blue Range Resource Corporation for cash consideration of $235.0 million and the issuance of 500,000 share purchase warrants entitling the holder to acquire, on or before August 16, 2001, one common share of the Company at a price of $30.00 per common share. The Company's 1999 acquisition and disposition activities resulted in the completion of 170 transactions at an aggregate net expenditure of $137.3 million.

The Company issued on May 28, 1999 $125.0 million 6.85% unsecured debentures maturing May 28, 2004 pursuant to a short form shelf prospectus dated February 22, 1999.

The Company issued 10,500,000 common shares at $38.00 per share pursuant to a short form prospectus offering dated August 24, 1999.

In July 2000 the Company acquired 100 percent of Ranger for a total purchase price of $1.7 billion. Ranger held a portfolio of producing and non-producing crude oil and natural gas properties in the Western Canadian Sedimentary Basin, the United States Gulf Coast, the UK sector of the North Sea, and offshore West Africa. The Offer to Purchase dated June 19, 2000 offered $8.25 cash per common share for each Ranger common share subject to an aggregate maximum of $650 million cash and to proration as described in the Offer to Purchase; or 0.175 common shares of CNRL, subject to an aggregate maximum of 10 million common shares and to proration as described in the Offer to Purchase. Pursuant to the Offer to Purchase, 7,602,068 common shares of CNRL were issued.

During 2000, the Company completed another 170 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $150.2 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition the Company disposed of non-operated Canadian properties owned by Ranger, not located in the Company's core areas, for proceeds of $128.0 million.

The Company issued on February 24, 2000 $125.0 million 7.40% unsecured debentures maturing March 1, 2007 pursuant to a short form shelf prospectus dated February 22, 1999.

In 2001, 121 transactions were completed by the Company in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $519.2 million. These properties are located in the Company’s principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company’s core areas for proceeds of $63.0 million, including a large portion of the properties acquired with Ranger in the United States Gulf Coast.

The Company issued on July 24, 2001US $400.0 million 6.70% unsecured notes maturing July 15, 2011 pursuant to a prospectus supplement dated July 19, 2001 to the short form shelf prospectus dated July 6, 2001. Pursuant to a prospectus supplement dated January 15, 2002 to the short form shelf prospectus dated July 6, 2001, the Company issued on January 23, 2002 US $400.0 million 7.20% unsecured notes maturing January 15, 2032.

REGULATORY MATTERS

The Company’s business is subject to regulations generally established by government legislation and governmental agencies. The regulations are summarized in the following paragraphs.

Canada

The petroleum and natural gas industry in Canada operates under various government legislation and regulations, which govern exploration, development, production, refining, marketing, prevention of waste and other activities.

The Company's Canadian properties are located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. Most of these properties are held under leases/licences obtained from the respective provincial or federal governments, which give the holder the right to explore for and produce crude oil and natural gas. The remainder of the properties is held under freehold (private ownership) lands.

Conventional petroleum and natural gas leases issued by Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a term of up to ten years. Those portions of the leases that are producing or are capable of producing at the end of the primary term will “continue” for the productive life of the lease. The exploration licences in the Northwest Territories are administered by the Federal Government and only grant the right to explore. They have initial terms of four to five years. A Commercial Discovery Licence must be obtained in order to produce crude oil and natural gas, which requires the approval of a satisfactory development plan.

An oil sands permit and oil sands primary lease is issued for 5 and 15 years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued out of the permit. A primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as “producing” will continue for their productive life while those designated as “non-producing” can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and natural gas liquids from each province. Government royalties are payable on crude oil and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 43 percent after allowable deductions.

International

Under existing law, the UK Government has broad authority to regulate the petroleum industry, including the power to regulate exploration, development, conservation and rates of production.

Production from offshore fields as defined by applicable legislation, whose development was approved prior to April 1,1982 is subject to Royalty of 12.5 percent on or after deduction of certain allowances. Fields receiving development approval after April 1, 1982 are not subject to Royalty.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK Petroleum Revenue Tax (“PRT”) of 50 percent charged on crude oil and natural gas profits. Crude oil and natural gas fields granted development approval on or after March 16, 1993 are exempted from PRT. Profits for PRT purposes are calculated on a field-by-field basis by deducting Royalty paid, field operating costs and field development costs from production and third party tariff revenue. In addition, certain statutory allowances are available which may reduce the PRT payable.

The Company is subject to UK Corporation Tax ("CT") on its UK profits as adjusted for CT purposes. PRT and Royalties paid are deductible for CT purposes. The current CT rate, which became effective April 1, 1999, is 30 percent.

On April 17, 2002, the UK Government, in its 2002 budget speech by the UK Chancellor of the Exchequer, announced changes to taxation policies on UK North Sea crude oil and natural gas production. A supplementary charge of 10%, excluding any deduction for financing costs, will be added to the current 30% CT and the capital allowance deduction for expenditures on plant and machinery was changed from 25% to 100% per year. In addition, the UK Government stated it intended to abolish the Royalty charged on older fields at a future date to be determined through consultation.

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and by concession within each country. Production from the Kiame field, on Block 4 in Angola, was subject to a six percent royalty on gross income and fifty percent Petroleum Income Tax, which equates to seven percent calculated on the Company’s gross income. The Company does not expect to pay more than this amount on royalty or tax on production from Kiame. Development of the Espoir field on CI-26, Côte d'Ivoire, is under the terms of a production sharing arrangement which provides that tax or royalty payments to the Government are deemed to be met from the Government's share of profit oil (See “Principal Crude Oil and Natural Gas Properties – Offshore West Africa”).

Any changes in government policies or operating environment in the countries where the Company conducts business could have a significant impact on the Company's business ventures in such jurisdictions. Risks of foreign operations include, but are not necessarily limited to, changes of laws affecting foreign ownership, government participation, taxation, royalties, duties, rates of exchange, inflation, exchange control, repatriation of earnings and domestic or international unrest. There are no assurances that the economic and political conditions in the countries in which the Company operates will continue in such countries as they are at the present time. The effect of any changes in any of these factors cannot be accurately predicted.

COMPETITIVE MATTERS

The crude oil and natural gas industry, domestically and in the international arena, is highly competitive by nature. The Company must compete with integrated oil and natural gas companies and independent producers and marketers of crude oil and natural gas products in all aspects of the Company’s business. This competition extends to exploration, property and asset acquisition and to the selling of the Company’s crude oil and natural gas products. The financial strength of some of the Company’s competitors may be greater than that of the Company.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and good industry practice. Environmental specialists in the UK and Canada review the operations of the Company’s world-wide interests and report on a regular basis to the senior management of the Company, which reports directly to the Board of Directors.

The Company regularly meets with, and submits to inspections by the various governments in the regions where the Company operates. At present, the Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the crude oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected. The Company's production facilities are relatively new and the likelihood of major capital expenditures being required to meet future changes is reduced in the near term. The Company has internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The Company’s environmental plan and operating guidelines focus on minimizing the environmental impact of field operations while meeting regulatory requirements and corporate standards. The Company’s proactive program includes: an annual environmental compliance audit and inspection program of our operating facilities; an aggressive 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; progressive due diligence related to groundwater monitoring; and, prevention of and reclaiming spill sites. During 2001, the Company realized emission reductions of more than one million tonnes annually of Carbon Dioxide Equivalent. CNRL participates in Canada’s Voluntary Challenge Registry Inc. (“VCR”). In 2001, for performance under this program, the Company received a gold award from VCR.

The costs incurred by the Company for compliance with environmental matters and site restoration costs amount to approximately one percent of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2001, 2000 and 1999.

DESCRIPTION OF THE BUSINESS

CNRL is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, natural gas liquids and natural gas. The Company's principal core areas of operations are western Canada, the United Kingdom sector of the North Sea and offshore West Africa.

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible CNRL takes on significant ownership levels, operates the properties and attempts to dominate the local land position and operating infrastructure. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either enter new core areas or increase dominance in existing core areas.

The Company's operations are centred on balanced product offerings, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold, accounting for 43 per cent of 2001 production. Virtually all of the Company's natural gas and natural gas liquids production is located in the Canadian provinces of Alberta and British Columbia and sold in Canada and the United States. Light oil, representing 20 per cent of 2001 production, is located principally in the Company's North Sea and offshore West Africa properties, with additional production in the Provinces of Saskatchewan, British Columbia and Alberta. Heavy oil operations in the Provinces of Alberta and Saskatchewan account for 27 per cent of 2001 production. Other heavy oil, which accounts for 10 per cent of 2001 production, is produced from the Pelican Lake area in central Alberta. This production, which has medium oil netback characteristics, is developed through a staged horizontal drilling program. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy and medium oil operations. CNRL expects its ownership of oil sands leases near Fort McMurray, Alberta will provide a basis for long-term synthetic oil production growth.

As a result of the Company's undeveloped land base of 6.5 million net acres in western Canada, its international concessions and the Alberta oil sands leases, the Company believes it has sufficient project portfolios in each of the product offerings to provide growth for the next several years.

A. PRINCIPAL CRUDE OIL AND NATURAL GAS PROPERTIES

Set forth below is a summary of the principal crude oil and natural gas properties as at December 31, 2001. The information relating to average production rates and reserve volumes is proportionate to the working interests and royalty interests owned by the Company.

	2001 AVERAGE DAILY PRODUCTION RATES		CRUDE OIL & NGL RESERVE VOLUMES (MMbbls)			NATURAL GAS RESERVE VOLUMES (Bcf)		
PROPERTY	OIL & NGLs Mbbls	GAS MMcf	PROVED RESERVES	PROBABLE RESERVES	* TOTAL RESERVES	PROVED RESERVES	PROBABLE RESERVES	TOTAL RESERVES
North America								
Northeast B.C./ Northwest Alberta	10.6	368.3	22	8	30	976	135	1,111
Northern Alberta	44.2	322.0	84	11	95	554	81	635
East Alberta/West Saskatchewan	97.0	35.3	486	73	559	222	38	260
Southern Alberta	6.7	162.3	21	3	24	677	66	743
Southeast Saskatchewan	6.5	2.2	23	1	24	14	-	14
Non - core areas	1.6	16.0	8	-	8	123	29	152
International								
United Kingdom North Sea	36.3	12.0	85	23	108	94	24	118
Offshore West Africa								
Angola	3.4	-	-	-	-	-	-	-
Côte d'Ivoire	-	-	61	50	111	69	27	96
Total	206.3	918.1	790	169	959	2,729	400	3,129

***** NGL's represent approximately 2 percent of the Company's total crude oil and NGL reserve volumes.

Northeast British Columbia/Northwest Alberta

This region comprises lands from south of Fort St. John, British Columbia to the northern border of British Columbia and straddles the B.C./Alberta border. Similar geological attributes extend from Alberta into British Columbia throughout the more than 50 separate fields developed by the Company in the region, producing light oil, natural gas liquids and natural gas. The Company holds working interests ranging up to 100 percent and averaging 79 percent in 2,906,926 gross (2,307,690 net) acres of producing and undeveloped land in the region.

Crude oil reserves are found primarily in the Halfway or lower Halfway formation, while natural gas and associated natural gas liquids are found in numerous zones at depths reaching approximately 2,000 vertical meters. In the southern portion of the region, the Company owns natural gas producing and undeveloped lands in which the productive zones are at depths up to 3,500 meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic geological areas close to existing infrastructure. Applying under-balanced multi-leg horizontal drilling has also proven highly effective in this region. A large proportion of the assets acquired during 1999 through the Plan of Arrangement proposed by the Company for the assets of Blue Range Resource Corporation were located in this region. Natural gas production from the region averaged 368 million cubic feet per day for 2001, an increase of 23 percent from the average of 300 million cubic feet per day produced for 2000 and 250 million cubic feet per day produced in 1999. Crude oil and natural gas liquids production decreased from 12.5 thousand barrels per day in 2000 to an average of 10.6 thousand barrels per day in 2001. Crude oil and natural gas liquids produced from the area averaged 11.2 thousand barrels per day in 1999.

This region contains the Ladyfern Slave Point natural gas pool, which is estimated to contain between 700 and 750 billion cubic feet of natural gas-in-place. During 2001, the Company drilled 8 net natural gas wells in the area with a total production capability of over 600 million cubic feet per day. Production from the area has been restricted due to insufficient processing facilities and pipelines. The Company entered into a production sharing agreement with other producers in the pool, which limits the total production from the pool to prevent over capitalization of facilities. In the first quarter of 2002, additional facilities were constructed to maximize the pool production cap at 785 million cubic feet per day. The pool production cap is allocated to each producer based upon the production capability of the producer's wells drilled into the pool. At the end of 2001, production net to the Company was at 150 million cubic feet per day.

Through the acquisition of Ranger in 2000, the Company acquired an interest and operatorship in extensive acreage adjacent to the northern border of this region. A further acquisition in the fourth quarter of 2001 resulted in the Company obtaining 100 per cent ownership in its producing natural gas assets and undeveloped land in the Helmet area of the region. This acreage also extends over the border of British Columbia into the Northwest Territories. Ranger had drilled a number of producing natural gas wells on the acreage. Further development of this acreage will be enhanced through the facilities and infrastructure owned by the Company in the region.

During 2001 the Company drilled 8.1 net oil wells, 74.6 net natural gas wells, and 9.5 net abandoned wells on its lands in this region for a total of 92.2 net wells. The Company held an average 77 percent working interest in these wells. In 2000, the Company drilled a total of 103.1 wells in this region. The Company owns and operates significant production facilities in this region including 12 net multi-well oil batteries, 76 net natural gas plants or compressor stations and extensive pipeline and gathering facilities. Interests are also owned in additional facilities operated by other industry participants. All of the facilities are in close proximity to sales facilities.

Northern Alberta

The Company holds working interests ranging up to 100 percent and averaging 87 percent in 4,477,885 gross (3,896,795 net) acres of producing and undeveloped land in the region.

Both sweet and sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 1,500 meters. In the southwest portion of the region, natural gas liquids and light oil are also encountered at slightly deeper depths. The region continues to be one of the Company's largest natural gas producing regions with natural gas production from the region amounting to 322 million cubic feet per day in 2001 compared to 300 million cubic feet per day in 2000 and 303 million cubic feet per day in 1999. Crude oil and natural gas liquids production from this region increased to 44.2 thousand barrels per day in 2001 from 35.0 thousand barrels per day in 2000 and 18.0 thousand barrels per day in 1999.

Included in the northern part of this region are the Company's 100 percent-owned holdings at Pelican Lake. These lands contain reserves of 14°-16° API heavy oil. Operating costs are low due to no sand production or disposal requirements, the gathering and pipeline facilities in place and negligible water production and disposal. The Company has the major ownership position in the necessary infrastructure including roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors to ensure future economic development of the large crude oil pool located on the lands. The Company's holdings in the area were further augmented with the acquisition in 1999 of additional lands and assets included in the acquisition from BP Amoco. In the first quarter of 2001, the Company added to its holdings in this area through the acquisition of additional producing lands from another industry participant. After these acquisitions, the Company holds and controls in excess of 80 percent of the known crude oil pool in this area.

During 2001, the Company drilled 53.6 net natural gas wells, 104.2 net oil wells, 12.0 net stratigraphic tests and 15.1 net wells that were abandoned for a total of 184.9 net wells. The Company's average working interest in these wells was in excess of 91 percent. In 2000 the Company drilled a total of 244.6 net wells. The Company operates and owns 87 net natural gas plants or compressor stations in the area. In addition, the Company owns and operates 18 net oil batteries and has additional interests in plants and compressors in the region, which are operated by other companies.

East Alberta/West Saskatchewan

The region comprises lands located from approximately Cold Lake to Lloydminster on the Alberta/Saskatchewan border. The Company holds working interests ranging up to 100 percent and averaging 88 percent in 1,947,331 gross (1,716,471 net) acres of producing and undeveloped land in the region.

Reserves of heavy oil (averaging 12° - 14° API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons up to 1,000 meters deep. The energy required to flow the heavy oil to the wellbore in this type of heavy oil reservoir comes from solution gas. The amount of solution gas together with the viscosity of the crude oil will determine the amount of crude oil produced from the reservoir, which will vary from three to twenty percent. A key component to maintaining profitability in the production of heavy oil is to be a low cost producer. The Company continues to achieve low costs by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

The price received for heavy oil is discounted from the benchmark WTI price and during the last quarter of 2000, this differential widened to historically high levels. As a result, the Company took a proactive stance and consciously reduced the number of heavy oil wells drilled in 2001, with a further reduction planned in 2002; reduced heavy oil production by 15,000 barrels per day beginning December 2001and changed the steaming pattern at its Primrose facility. The heavy oil differential has narrowed to more historical levels and the Company continues to monitor this market and work on strategies to eliminate some of the uncertainty surrounding this commodity pricing.

Daily production from the region increased in 2001 to 97.0 thousand barrels of crude oil and 35 million cubic feet of natural gas compared to 91.0 thousand barrels of crude oil and 30 million cubic feet of natural gas in 2000 and 43.1 thousand barrels of crude oil and 28 million cubic feet of natural gas per day in 1999.

Ranger owned significant land and production in this area, with much of its land being contiguous to CNRL holdings. With the operations combined, future development of the total lands in the area became more effective and provides opportunities for cost savings. As part of the acquisition of Ranger, the Company also acquired a 50 percent interest in the ECHO Pipeline system, a crude oil transportation pipeline; and, in 2001 the Company acquired the remaining 50 percent. The pipeline was extended to the Beartrap field during 2001, enhancing further development of the Company's extensive holdings in the area. This pipeline is capable of transporting 57,000 barrels per day of hot unblended crude oil to sales facilities at Hardisty, Alberta. With minor upgrades, its capability can be expanded to handle up to 75,000 barrels per day. The ECHO Pipeline system is a high temperature, insulated pipeline that eliminates the requirement for field condensate blending. The pipeline will enable the Company to transport its own production volumes at a reduced operating cost as well as earn third party transportation revenue. The ECHO Pipeline system together with other midstream assets, which the Company has partial interests in, permits CNRL to transport in excess of 75% of its heavy oil to the international mainline liquids pipelines. This transportation control enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy oil.

Included in the assets acquired from BP Amoco was a 100 percent interest in oil sands leases located in this region at Primrose and Wolf Lake. Production from these lands involves processes that utilize steam to increase the recovery of the oil. The two processes employed by the Company are cyclic steam stimulation and SAGD. Both recovery processes inject steam to heat the heavy oil deposits, reducing the oil viscosity and therefore improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 60,000 barrels per day and a 50 percent interest in a co-generation facility capable of producing 85 megawatts of electricity for the Company's use or sale into the power grid at pool prices. In 2000, the Company successfully converted and tested two existing pads of wells from low pressure steaming to high pressure steaming. This conversion increased average production at the 20 existing wells from 100 to 190 barrels of crude oil per day per well. An additional 24 wells were drilled using the high-pressure steam process with initial production averaging 600 barrels of crude oil per day per well. These results have confirmed the benefits of converting the Primrose field to high pressure steaming. In 2001 the Company received regulatory approval to convert an additional 3 low pressure cyclic pads to high pressure cyclic pads which should result in the Company being better able to control steam injection volumes and timing. Production from these high pressure pads is expected to commence in the second or third quarter of 2002. CNRL has also commenced a pilot project to determine the economic feasibility of burning produced heavy oil instead of natural gas to generate steam for its thermal operations to mitigate the effect of high natural gas prices on its production cost of thermal heavy oil. Additional development of the leases will be undertaken in phases over the next several years. A successful SAGD heavy oil project in which the Company holds a 50 percent interest is also in operation in the Saskatchewan portion of this region.

During 2001, the Company drilled a total of 103.0 net oil wells, 31.1 net natural gas wells, 67.5 stratigraphic test wells, 15.0 net service wells and 5.7 net wells that were abandoned for a total of 222.3 net wells. The Company holds an average interest of 95 percent in these wells. This compares to 210.1 net wells in 2000. In this region, the Company owns and operates 14 net oil batteries and 15 net compressor stations as well as the related gathering and other processing facilities.

Oil Sands - Horizon Project

In the Fort McMurray area of Alberta, the Company holds working interests ranging up to 100 per cent and averaging 85 per cent in 276,908 gross (236,479 net) acres of undeveloped oil sands in the region containing mineable bitumen. The oil sands lie close to the surface and once overburden is stripped away, the bitumen can be removed and trucked to a processing plant for extraction and upgrading to synthetic oil, or can be accessed by using in-situ production methods.

The Company owns 100 per cent of the leases in 99,000 gross acres located in this area comprising the Horizon Project. During 2001, the Company filed a public disclosure document as the initial step in making application to obtain regulatory approval for a long-term oil sands project which has four components: surface mining and bitumen processing, in-situ operations, an upgrader and associated infrastructure. Formal application is expected to be made by mid-2002. The first phase of the front-end engineering work on the Horizon project has been completed. An Environment Impact Assessment was undertaken and will be submitted to the regulatory authorities in the second quarter of 2002. The project will provide for a potential recovery of 6 billion barrels of bitumen over an estimated 50-year life span. CNRL anticipates start of construction in 2004 with first synthetic oil production as early as 2006 with full capacity by 2010 of 300 thousand barrels per day of bitumen. No reserves from these leases are included in the Company’s reserves of crude oil and natural gas liquids.

During 2001, the Company drilled 257.0 stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

Southern Alberta

The region was added to the Company's focused areas of operation in mid-1996 with the acquisition of Sceptre and expanded with the acquisition of lands owned by Ranger. The Company holds interests ranging up to 100 percent and averaging 84 percent in 1,759,153 gross (1,474,673 net) acres of producing and undeveloped land in the region.

Reserves of natural gas, condensate and light and medium gravity crude oil are contained in numerous productive horizons at depths up to 2,300 meters. Unlike the Company’s other two natural gas producing regions, which have areas with limited or winter access only, drilling can take place in this region year round. With a higher sales price for natural gas it is economic to drill shallow wells in closer proximity to each other which may have smaller overall reserves and lower productivity per well but will achieve a high return on capital employed.

The Company's share of production averaged 6.7 thousand barrels of crude oil and natural gas liquids per day and 162 million cubic feet of natural gas per day in 2001. Average daily production realized by the Company in 2000 amounted to 7.3 thousand barrels of crude oil and natural gas liquids and 150 million cubic feet of natural gas and 7.0 thousand barrels of crude oil and natural gas liquids and 134 million cubic feet of natural gas in 1999.

During 2001, the Company drilled a total of 8.9 net oil wells, 316.4 net natural gas wells and 1.0 net abandoned wells in this region for a total of 326.3 net wells. The Company’s average working interest in these wells is 82 percent. In 2000 the Company drilled 238.0 net wells in this region. The wells are predominantly in areas where the Company already has gathering and processing facilities. The Company owns and operates 24 net oil batteries and 27 net natural gas plants or compressor stations in the area.

Southeast Saskatchewan

The Williston Basin is located in Southeastern Saskatchewan with lands extending into Manitoba and North Dakota. This region was owned by Sceptre and became a core area of the Company in mid 1996 with the acquisition of Sceptre. The Company holds interests ranging up to 100 percent and averaging 84 percent in 257,965 gross (217,971 net) acres of producing and undeveloped lands in the region.

The region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters. During 2001, production to the Company averaged 6.5 thousand barrels of crude oil per day compared to an average of 6.8 thousand barrels of crude oil per day in 2000 and 6.3 thousand barrels of crude oil per day in 1999.

The Company drilled 4.0 net oil wells in 2001 with an average 67 percent working interest. In 2000, the Company drilled 12.6 net wells in this region. These wells included a number of horizontal wells that further developed the existing known pools of crude oil in the Company's lands. The Company owns appropriate production facilities, including 31 net oil batteries and gathering systems in close proximity to sales facilities.

United Kingdom North Sea

The Company’s wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, has operated in the North Sea for 30 years and has developed a significant database, extensive operating experience and an experienced staff. The Company owns interests ranging from 4 percent up to 40 percent in 904,517 gross (255,951 net) acres of producing and non-producing acreage in the UK sector of the North Sea. In 2001, the Company produced from 12 crude oil and natural gas fields.

The most northerly fields are centered around the Ninian field where the Company has a 24.1 percent working interest. The central processing facility is connected to other fields including the Columba fields where the Company operates with working interests of 32 percent to 34 percent. The Company also receives tariff revenue from other operators for the transportation and processing of crude oil and natural gas through the processing facilities. Opportunities for further long reach well development on adjacent fields are provided from the existing processing facilities.

In the central portion of the North Sea, the Company owns a 26.2 percent working interest in the Banff field and a 40 percent operated working interest in the Kyle field. Production at the Banff field was temporarily curtailed in September 2000 while the owners of the FPSO removed the vessel from the field to make repairs and modifications. Production resumed from the field in 2001. At the Kyle field the Company drilled one additional well and during the summer of 2000 produced this well on an extended well test to confirm reservoir quality. A third well was drilled, tested and connected to production facilities in 2001. The wells at Kyle are tied into an FPSO located at the Curlew field, which the Company took over operatorship of in 2001. Increased production from the U. K. sector of the North Sea in 2001 is due to the new production in the Company operated fields of Kyle and Columba and the recommencement of production from the Banff field.

During 2001, production to the Company from this region averaged 36.3 thousand barrels of crude oil per day and 12 million cubic feet of natural gas per day compared to an average production to the Company in 2000 of 35.0 thousand barrels of crude oil per day and 3 million cubic feet of natural gas per day after being acquired by the Company in 2000. The Company drilled 2.2 net oil wells, 0.6 net service wells and 0.2 net abandoned wells for a total of 2.9 net wells in 2001 in this region with an average working interest of 18 per cent. This compares to 0.9 net oil wells and 0.1 net injection wells in the last half of 2000.

Offshore West Africa

With the purchase of Ranger in 2000, the Company acquired interests in areas of crude oil and natural gas exploration and development offshore Côte d'Ivoire and Angola, West Africa. The Company owns working interests ranging from 25 percent to 100 percent in 2,323,122 gross (1,103,840 net) acres in this region.

Côte d'Ivoire

The Company owns interests in five exploration licences offshore Côte d'Ivoire comprising 798,403 net acres. During 2001 the Company increased its interest in Block CI-26, which contains the Espoir crude oil and natural gas field, to a 59 percent operating interest. The Espoir field is located in water depths ranging from 100 to 700 meters. During the 1980s the Espoir field produced 31 million barrels of crude oil by natural depletion prior to relinquishment by the previous licencees in 1988. The government of Côte d'Ivoire approved a development plan to recover the remaining reserves and the Company will continue its exploitation and development of the field. The development of East Espoir, which includes the drilling of both producing and water injection wells from a single wellhead tower, is proceeding on schedule. Development of the West Espoir field will proceed after full development of East Espoir, in approximately three years. Using an FPSO with a capacity of 40,000 barrels of crude oil per day, crude oil production commenced in the first quarter of 2002 at an initial rate of 8,500 barrels of crude oil per day from one producing well with increased production expected over the next several months to 30,000 barrels of crude oil per day by the fourth quarter of 2002. A subsea pipeline has been constructed for the delivery of associated natural gas to onshore Côte d'Ivoire where it will be sold to local power producers. In the first quarter of 2001 the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, in which the Company has a 61 per cent interest, eight kilometres south of the Espoir facilities. The well encountered hydrocarbons at a rate of 6,700 barrels of crude oil per day. Seismic surveys have been acquired on the other Côte d'Ivoire blocks and leads or prospects identified.

During 2001, the Company drilled 1.2 net oil wells and 0.6 net service wells for a total of 1.8 net wells with an average working interest of 59 per cent.

Angola

The Company owns 100 percent of and operates the Kiame field situated offshore The People's Republic of Angola. The field has been on production since June 1998 through a leased FPSO and in 2001 production averaged 3.4 thousand barrels of crude oil per day decreasing from 5.1 thousand barrels of crude oil per day averaged in the last half of 2000. The field has reached its economic limit of production and production ceased in April 2002. The Company has a 25 percent non-operating interest in Block 19, a 1.2 million-acre block, which lies in water depths of 300 to 1,800 meters. A 2,500 square kilometre 3-D seismic survey was completed in 1999 and is currently under interpretation. The Company is evaluating other opportunities to participate in the Angola deepwater Tertiary play.

B. CRUDE OIL AND NATURAL GAS RESERVES

The Company retains independent petroleum engineering consultants Sproule Associates Limited (“Sproule”) to evaluate the Company's proved and probable crude oil and natural gas reserves and prepare an evaluation report on the Company's total reserves ("Evaluation Report"). For the year ended December 31, 2001, the Evaluation Report covered 91 percent of the Company's reserves with the Company internally evaluating the remaining 9 percent, which are generally comprised of reserves in properties not currently strategic to the Company's core business areas. The Company has retained Sproule since 1989 to evaluate its assets.

The Board of Directors Reserve Committee met with Sproule and carried out independent due diligence procedures with Sproule as to the Company’s reserves.

The following tables summarize the evaluations of reserves and estimated future net production revenues at December 31, 2001.

The estimated future net revenues contained in the following tables are not to be construed as a representation of the fair market value of the properties to which they relate. The present worth of all probable reserves has been reduced by 50 percent to account for risk. The estimated future net revenues derived from the assets take into account the effect of ARTC, processing revenues and Corporate Capital Gas Cost Allowance but are prepared prior to consideration of income taxes and abandonment liabilities. No indirect costs such as overhead, interest and administrative expenses have been deducted from the estimated future net revenues. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

Crude Oil, NGL and Natural Gas Reserves

	Escalated Prices and Costs			
	Crude Oil and Natural Gas Liquids		Natural Gas	
	Gross	Net	Gross	Net
	(MMbbls)		(Bcf)	
Proved developed producing	398	360	2,139	1,727
Proved developed non-producing	59	54	185	151
Proved undeveloped	333	305	405	345
Total proved reserves	790	719	2,729	2,223
Probable reserves	169	152	400	324
Total proved and probable reserves	959	871	3,129	2,547

Estimated Future Net Revenues

	Escalated Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
		($ Millions)		
Proved developed producing	$11,828	$7,084	$6,030	$5,289
Proved developed non-producing	1,196	766	649	562
Proved undeveloped	4,263	1,699	1,177	844
Total proved reserves	17,287	9,549	7,856	6,695
Probable reserves	1,860	847	642	506
Total proved and probable reserves	$19,147	$10,396	$8,498	$7,201

Crude Oil, NGL and Natural Gas Reserves

	Constant Prices and Costs			
	Crude Oil and Natural Gas Liquids		Natural Gas	
	Gross	Net	Gross	Net
	(MMbbls)		(Bcf)	
Proved developed producing	398	360	2,139	1,728
Proved developed non-producing	59	55	185	152
Proved undeveloped	331	306	405	345
Total proved reserves	788	721	2,729	2,225
Probable reserves	169	153	400	325
Total proved and probable reserves	957	874	3,129	2,550

Estimated Future Net Revenues

	Constant Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
		($Millions)		
Proved developed producing	$9,679	$6,235	$5,406	$4,809
Proved developed non-producing	972	654	562	493
Proved undeveloped	3,032	1,275	893	644
Total proved reserves	13,683	8,164	6,861	5,946
Probable reserves	1,448	707	543	433
Total proved and probable reserves	$15,131	$8,871	$7,404	$6,379

NOTES

1. "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by the Company before deduction of royalties payable to others.

2. "Net" reserves mean the Company's gross reserves less all royalties payable to others.

3. "Proved developed producing" reserves are those proved reserves that are presently being produced from completion intervals open for production in existing wells with existing equipment and operating methods.

4. "Proved developed non-producing" reserves are those proved reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These proved reserves are expected to be produced through the existing wells in the predictable future and are classified as proved developed since the cost of making such reserves available for production is relatively small, compared to the cost of a new well.

5. "Proved undeveloped" reserves are those proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

6. "Proved" reserves are those quantities of crude oil, natural gas and natural gas liquids, which, upon analysis of geologic and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known crude oil and natural gas reservoirs under presently anticipated economic and operating conditions for the escalated prices and costs case and under existing economic and operating conditions for the constant prices and costs case.

7. "Probable" reserves are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions

which contain proved reserves. **The estimated future net revenues of the probable reserves set forth above have been risk weighted by 50 percent to account for the probability of obtaining production from such reserves.**

8. Canadian securities legislation and policies permit the disclosure, which is included or incorporated by reference herein under a multi-jurisdicitional disclosure system adopted by the SEC, of probable reserves which may not be disclosed in registration statements otherwise filed with the SEC. Probable reserves are generally believed to be less likely to be recovered than proved reserves. The reserve estimates, included or incorporated by reference in this Annual Information Form could be materially different from the quantities and values ultimately realized.

9. All values are shown in Canadian dollars.

10. The escalated price and cost case assumes the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed below and adjusted for quality of reserves and contract conditions. Subsequent to 2013, reference prices and costs are escalated at 1.5 percent per year. Future crude oil, natural gas liquids and natural gas price forecasts were based on Sproule's January 1, 2002 crude oil, natural gas liquids and natural gas pricing model.

    The principal crude oil and natural gas price forecasts used in the Evaluation Reports are as follows:

	NATURAL GAS				CRUDE OIL				
YEAR	Company Average Price $CDN/Mcf	Henry Hub Louisiana $US/Mmbtu	AECO $CDN/Mmbtu	British Columbia Plantgate $CDN/Mmbtu	Company Average Price $CDN/bbl	WTI @ Cushing (i) $US/bbl	Hardisty Heavy 12° API $US/bbl	Edmonton Par (ii) $CDN/bbl	Brent UK $US/bbl
2002	3.80	2.89	3.80	3.75	18.36	19.90	14.41	29.86	18.40
2003	4.33	3.24	4.35	4.30	20.85	20.64	18.44	30.96	19.11
2004	4.32	3.25	4.36	4.26	23.44	21.12	21.58	31.67	19.29
2005	4.33	3.25	4.36	4.26	23.75	21.44	22.13	32.15	19.58
2006	4.42	3.29	4.44	4.34	24.01	21.76	22.62	32.65	19.87
2007	4.49	3.34	4.51	4.41	24.32	22.08	23.09	33.14	20.17
2008	4.55	3.39	4.59	4.49	24.42	22.42	23.56	33.65	20.47
2009	4.59	3.44	4.67	4.57	24.59	22.75	24.04	34.16	20.78
2010	4.67	3.50	4.76	4.66	24.69	23.09	24.53	34.68	21.09
2011	4.72	3.55	4.84	4.74	25.12	23.44	25.02	35.20	21.41
2012	4.78	3.60	4.92	4.82	25.58	23.79	25.52	35.74	21.73
2013	4.87	3.66	5.01	4.91	26.71	24.15	26.03	36.28	22.05

(i) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.

(ii) "Edmonton Par Price" refers to the price of light gravity (40^{o} API), low sulphur content crude oil at Edmonton, Alberta.

11. Product prices in the constant price evaluation are those in effect at the end of the year adjusted for the average light oil to heavy oil differential used for 2002 in the escalated price evaluation. The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Evaluation Report. Product prices have not been escalated beyond 2002. In addition, operating and capital costs have not been increased on an inflationary basis.

12. Estimated future net revenue from all assets is income derived from the sale of net reserves of crude oil, natural gas and natural gas liquids, less all capital costs, production taxes, and operating costs and before provision for income taxes and administrative overhead costs.

13. The estimated total capital costs net to the Company necessary to achieve the estimated future net proved and risked weighted probable production revenues are:

	Escalated Price Case ($Millions)	Constant Price Case ($Millions)
2002	367	367
2003	497	490
2004	342	332
2005	98	93
2006	121	115
2007	67	62
2008	96	88
2009	140	126
Thereafter	49	40
	1,777	1,713

14. Estimated future net revenue includes the Alberta Royalty Tax Credit which, in both the escalated and constant price case, is estimated to be $20.8 million undiscounted and $5.1 million, $3.6 million and $2.7 million discounted at 10%, 15% and 20% respectively.

15. Estimated future net revenue includes the value of the Company's Corporate Capital GCA - Alberta Crown Credits which, in both the escalated and constant price case is estimated to be $59.0 million undiscounted and $50.2 million, $46.7 million and $43.8 million discounted at 10%, 15% and 20% respectively.

16. Estimated future net revenue includes the value of the Company's midstream assets is estimated to be $636.5 million undiscounted and $276.0 million, $211.2 million and $171.6 million in the escalated price case discounted at 10%, 15% and 20% respectively. In the constant price case the value of the Company's midstream assets is estimated to be $641.7 million undiscounted and $279.8 million, $214.1 million and $173.7 million discounted at 10%, 15% and 20% respectively.

17. The Evaluation Report was based upon data supplied by the Company with respect to quality and heating value adjustments, interests owned, royalties payable, operating costs and contractual commitments. No field inspection was conducted.

C. RECONCILIATION OF CHANGES IN RESERVES

The following table summarizes the changes in reserves before deduction of royalties payable to others during the past year:

	Crude oil and natural gas liquids (Mmbbls)				Natural gas (Bcf)			
	North America	**North Sea**	**Offshore West Africa**	**Total**	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Proved Reserves								
Reserves, December 31, 2000	642	102	37	781	2,360	91	66	2,517
Extensions and discoveries	14	-	38	52	470	1	-	471
Property purchases	16	-	8	24	167	-	24	191
Property disposals	(1)	-	-	(1)	(25)	-	-	(25)
Production	(61)	(13)	(1)	(75)	(331)	(4)	-	(335)
Revisions of prior estimates	34	(4)	(21)	9	(75)	6	(21)	(90)
Reserves, December 31, 2001	644	85	61	790	2,566	94	69	2,729
Probable Reserves								
Reserves, December 31, 2000	88	33	9	130	402	23	19	444
Extensions and discoveries	(1)	(1)	-	(2)	9	(1)	-	8
Property purchases	1	-	19	20	23	-	11	34
Property disposals	-	-	-	-	(6)	-	-	(6)
Revisions of prior estimates	7	(9)	23	21	(79)	2	(3)	(80)
Reserves December 31, 2001	95	23	51	169	349	24	27	400
Total Reserves December 31, 2001	739	108	112	959	2,915	118	96	3,129

D. CRUDE OIL AND NATURAL GAS PRODUCTION

The Company's working interest share of oil, NGLs and natural gas production and revenues received for the last two financial years is summarized in the following tables:

	YEAR ENDED DECEMBER 31				
	2001	2000	1999	1998	1997
Daily Production					
Crude Oil and NGLs (Bpd)	206,323	173,591	86,750	75,744	70,619
Natural Gas (MMcfd)	918.1	794.4	721.0	672.6	625.5
Annual Production					
Crude Oil and NGLs (Mbbls)	75,308	63,534	31,664	27,646	25,776
Natural Gas (Bcf)	335.1	290.8	263.2	245.5	228.3

CRUDE OIL, NGL and NATURAL GAS PRODUCTION
INFORMATION BY QUARTER

	Year 2001					**Year 2000**				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes										
Crude Oil and NGL (bbls)	205,588	214,716	207,064	198,000	206,323	138,735	145,519	206,696	202,732	173,592
Natural Gas (mcf)	850.8	884.6	923.8	1,011.6	918.1	734.0	766.2	844.5	831.8	794.4
Product Netbacks										
Oil and Liquids ($/bbl)										
Sales Price	$ 22.06	$ 25.32	$ 28.37	$ 21.28	$ 24.31	$ 29.45	$ 29.48	$ 35.23	$ 25.37	$ 29.99
Royalties	2.36	2.42	2.47	1.41	2.17	3.06	2.91	3.36	2.83	3.05
Production Expenses	7.88	7.32	7.10	7.41	7.42	5.01	5.10	6.97	7.60	6.38
Netback	**$ 11.82**	**$ 15.58**	**$ 18.80**	**$ 12.46**	**$ 14.72**	**$ 21.38**	**$ 21.47**	**$ 24.90**	**$ 14.94**	**$ 20.56**
Natural Gas ($/mcf)										
Sales Price	$ 9.30	$ 5.93	$ 3.12	$ 2.94	$ 5.16	$ 2.67	$ 3.55	$ 4.30	$ 7.28	$ 4.53
Royalties	2.40	1.47	0.67	0.62	1.25	0.52	0.81	1.05	1.83	1.08
Production Expenses	0.50	0.50	0.50	0.53	0.51	0.41	0.42	0.45	0.47	0.44
Netback	**$ 6.40**	**$ 3.96**	**$ 1.95**	**$ 1.79**	**$ 3.40**	**$ 1.74**	**$ 2.32**	**$ 2.80**	**$ 4.98**	**$ 3.01**
Crude Oil and NGL Netbacks by Type										
Light/Medium/NGLs ($/bbl)										
Sales Price	$ 30.96	$ 33.59	$ 32.75	$ 26.95	$ 31.13	$ 33.54	$ 32.70	$ 39.37	$ 34.59	$ 35.69
Royalties	4.03	3.86	3.30	2.29	3.38	4.69	4.63	3.92	4.33	4.31
Production Expenses	5.99	6.10	6.12	7.15	6.34	3.77	3.73	7.12	6.67	5.80
Netback	**$ 20.94**	**$ 23.63**	**$ 23.33**	**$ 17.51**	**$ 21.41**	**$ 25.08**	**$ 24.34**	**$ 28.33**	**$ 23.59**	**$ 25.58**
Heavy ($/bbl)										
Sales Price	$ 12.76	$ 15.83	$ 23.21	$ 14.85	$ 16.63	$ 26.63	$ 27.12	$ 30.37	$ 15.13	$ 24.62
Royalties	0.61	0.77	1.50	0.43	0.83	1.95	1.68	2.71	1.18	1.88
Production Expenses	9.85	8.72	8.26	7.69	8.65	5.86	6.10	6.80	8.64	6.92
Netback	**$ 2.30**	**$ 6.34**	**$ 13.45**	**$ 6.73**	**$ 7.15**	**$ 18.82**	**$ 19.34**	**$ 20.86**	**$ 5.31**	**$ 15.82**

NOTE: Reference to medium oil in this table includes crude oil with an API of 14º to 16º produced from the Company's Pelican Lake crude oil pool.

NETBACKS
INFORMATION BY QUARTER

	Year 2001					Year 2000				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
SEGMENTED										
North America Product Netbacks										
Light/Medium/NGL ($/bbl)										
Sales Price	$ 27.04	$ 27.49	$ 29.95	$ 23.83	$ 27.10	$ 33.54	$ 32.70	$ 35.95	$ 30.93	$ 33.31
Royalties	4.57	5.04	4.17	2.79	4.16	4.69	4.63	5.14	5.22	4.96
Production Expenses	3.84	4.02	4.22	4.74	4.19	3.77	3.73	5.23	5.29	4.57
Netback	**$ 18.63**	**$ 18.43**	**$ 21.56**	**$ 16.30**	**$ 18.75**	**$ 25.08**	**$ 24.34**	**$ 25.58**	**$ 20.42**	**$ 23.78**
Heavy ($/bbl)										
Sales Price	$ 12.76	$ 15.83	$ 23.21	$ 14.85	$ 16.63	$ 26.63	$ 27.12	$ 29.67	$ 14.68	$ 24.33
Royalties	0.61	0.77	1.50	0.43	0.83	1.95	1.68	2.71	1.18	1.88
Production Expenses	9.85	8.72	8.26	7.69	8.65	5.86	6.10	6.80	8.64	6.92
Netback	**$ 2.30**	**$ 6.34**	**$ 13.45**	**$ 6.73**	**$ 7.15**	**$ 18.82**	**$ 19.34**	**$ 20.16**	**$ 4.86**	**$ 15.53**
Natural Gas ($/mcf)										
Sales Price	$ 9.30	$ 5.99	$ 3.13	$ 2.94	$ 5.19	$ 2.67	$ 3.55	$ 4.30	$ 7.28	$ 4.53
Royalties	2.40	1.49	0.68	0.63	1.26	0.52	0.81	1.05	1.83	1.08
Production Expenses	0.50	0.50	0.50	0.52	0.50	0.41	0.42	0.45	0.47	0.44
Netback	**$ 6.40**	**$ 4.00**	**$ 1.95**	**$ 1.79**	**$ 3.43**	**$ 1.74**	**$ 2.32**	**$ 2.80**	**$ 4.98**	**$ 3.01**
North Sea Product Netbacks										
Light Oil ($/bbl)										
Sales Price	$ 41.04	$ 43.07	$ 37.28	$ 33.39	$ 38.66	$ -	$ -	$ 45.22	$ 43.86	$ 44.61
Royalties	2.86	2.23	1.97	1.52	2.10	-	-	2.00	2.89	2.40
Production Expenses	9.22	8.42	8.09	10.54	9.00	-	-	9.13	8.09	8.66
Netback	**$ 28.96**	**$ 32.42**	**$ 27.22**	**$ 21.33**	**$ 27.56**	**$ -**	**$ -**	**$ 34.09**	**$ 32.88**	**$ 33.55**
Natural Gas ($/mcf)										
Sales Price	$ -	$ 1.74	$ 2.51	$ 3.00	$ 2.51	$ -	$ -	$ 3.65	$ 3.78	$ 3.66
Royalties	-	-	-	-	-	-	-	-	-	-
Production Expenses	-	0.61	0.74	1.34	0.94	-	-	0.84	-	0.79
Netback	**$ -**	**$ 1.13**	**$ 1.77**	**$ 1.66**	**$ 1.57**	**$ -**	**$ -**	**$ 2.81**	**$ 3.78**	**$ 2.87**
Offshore West Africa Product Netbacks										
Light Oil ($/bbl)										
Sales Price	$ 40.58	$ 39.75	$ 34.66	$ 19.56	$ 33.57	$ -	$ -	$ 54.05	$ 39.10	$ 45.77
Royalties	$ -	$ 0.65	$ 2.03	$ 0.64	$ 0.93	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 38.80	$ 17.23	$ 19.05	$ 19.15	$ 21.77	$ -	$ -	$ 22.75	$ 18.53	$ 20.41
Netback	**$ 1.78**	**$ 21.87**	**$ 13.58**	**$ (0.23)**	**$ 10.87**	**$ -**	**$ -**	**$ 31.30**	**$ 20.57**	**$ 25.36**

NOTE: Reference to medium oil in this table includes crude oil with an API of 14º to 16º produced from the Company's Pelican Lake crude oil pool.

E. DRILLING ACTIVITY

The following table sets forth the gross and net wells in which the Company has participated for the period indicated:

	YEAR ENDED DECEMBER 31									
	2001		2000		1999		1998		1997	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Natural Gas	576	475.7	474	408.1	481	457.6	216	193.2	237	199.6
Crude Oil	270	231.6	375	333.1	229	211.5	120	106.5	486	442.9
Injection/Stratographic	356	352.7	42	37.7	11	8.9	20	15.5	2	1.5
Dry	36	32.3	46	34.4	54	49.3	48	42.7	75	67.0
Total	1,238	1,092.3	937	813.3	775	727.3	404	357.9	800	711.0
Total Success Rate		97%		96%		93%		88%		91%

F. CAPITAL EXPENDITURES

Costs incurred by the Company in respect of its programs of acquisition and disposition, and exploration and development of crude oil and natural gas properties, are summarized in the following tables:

	YEAR ENDED DECEMBER 31				
	2001	2000	1999	1998	1997
			($Millions)		
Corporate acquisition	$ -	$1,687.3	$ -	$ -	$ -
Net property acquisitions	519.2	150.2	1,422.3	63.9	386.3
Land acquisition and retention	100.5	79.7	46.2	39.0	98.3
Seismic evaluation	94.6	40.5	17.9	17.2	38.9
Well drilling, completion and equipping	644.7	524.0	274.8	255.2	350.7
Pipeline and production facilities	395.0	335.7	143.2	205.7	240.3
Reserve replacement expenditures	1,754.0	2,817.4	1,904.4	581.0	1,114.5
Projects under construction	-	-	(6.5)	25.4	-
Midstream operations	97.3	-	-	-	-
Oil sands	26.8	-	-	-	-
Head office equipment	6.4	5.9	2.7	3.3	4.6
Total Net Capital Expenditures	$1,884.5	$2,823.3	$1,900.6	$ 609.7	$1,119.1

CAPITAL EXPENDITURES BY QUARTER	2001 THREE MONTHS ENDED ($Millions) MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Corporate acquisition	$ -	$ -	$ -	$ -
Net property acquisitions	190.7	55.5	24.6	248.4
Land acquisition and retention	27.7	21.5	35.8	15.5
Seismic evaluation	37.0	20.2	8.6	28.8
Well drilling, completion and equipping	228.4	152.8	153.6	109.9
Pipeline and production facilities	111.4	105.0	109.7	68.9
Net reserve replacement expenditures	595.2	355.0	332.3	471.5
Midstream operations	28.9	6.8	16.1	45.5
Oil sands	9.1	4.8	1.9	11.0
Head office equipment	1.5	1.4	1.8	1.7
Total Net Capital Expenditures	$ 634.7	$ 368.0	$ 352.1	$ 529.7

CAPITAL EXPENDITURES BY QUARTER	2000 THREE MONTHS ENDED ($Millions) MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Corporate acquisition	$ -	$ -	$ 1,687.3	$ -
Net property acquisitions	185.9	68.3	(11.3)	(92.7)
Land acquisition and retention	8.9	11.4	13.7	45.7
Seismic evaluation	11.1	1.1	10.2	18.1
Well drilling, completion and equipping	159.0	107.7	131.5	125.8
Pipeline and production facilities	102.3	58.5	76.7	98.2
Net reserve replacement expenditures	467.2	247.0	1,908.1	195.1
Midstream operations	-	-	-	-
Oil sands	-	-	-	-
Head office equipment	1.3	3.5	0.8	0.3
Total Net Capital Expenditures	$ 468.5	$ 250.5	$ 1,908.9	$ 195.4

G. NON-RESERVE ACREAGE

The following table summarizes the Company's working interest holdings in core area non-reserve acreage earned by the Company as at December 31, 2001:

	Gross Acres	Net Acres
North America		
Alberta	5,289,772	4,652,928
British Columbia	1,693,152	1,387,094
Saskatchewan	490,010	441,119
Manitoba	1,170	1,170
Northwest Territories	27,555	10,037
North Dakota, USA	5,144	2,572
United Kingdom		
North Sea	798,774	236,903
Offshore West Africa		
Angola	1,200,420	300,105
Côte d'Ivoire	1,109,370	793,709
Total	10,615,367	7,825,637

SELECTED FINANCIAL INFORMATION

The following table summarizes the consolidated financial statements of the Company, which follows the full cost method of accounting for crude oil and natural gas operations.

	YEAR ENDED DECEMBER 31				
	2001	2000	1999	1998	1997
	($ millions, except per share information)				
Net revenues (net of royalties)	2,981.1	2,716.3	1,098.9	760.8	768.7
Cash flow from operations attributable to common shareholders	1,920.0	1,883.6	723.5	444.2	503.0
Per common share - basic	15.83	16.14	6.96	4.47	5.13
Net earnings attributable to common shareholders	698.2	782.2	200.2	59.0	111.3
Per common share - basic	5.76	6.70	1.93	0.59	1.14
Total assets	9,040.7	7,775.6	4,850.8	3,247.4	2,931.1
Total long-term debt	2,669.2	2,454.5	2,156.8	1,425.5	1,136.3

	2001 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ millions, except per share information)			
Net revenues (net of royalties)	893.7	807.8	701.3	578.3
Net earnings attributable to common shareholders	264.5	249.4	132.3	52.0
Per common share - basic	2.17	2.06	1.10	0.43

	2000 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ millions, except per share information)			
Net revenues (net of royalties)	476.6	542.8	858.6	838.3
Net earnings attributable to common shareholders	142.3	175.5	241.2	223.2
Per common share - basic	1.27	1.55	2.04	1.84

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

The Company's common shares are listed and posted for trading on The Toronto Stock Exchange and the New York Stock Exchange under the symbol CNQ and CED, respectively.

On January 17, 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange, beginning January 22, 2001 and ending January 21, 2002, to purchase for cancellation up to 6,114,726 common shares of the Company, being 5 percent of the 122,294,533 common shares of the Company outstanding on January 17, 2001. During this period, 2,537,800 common shares were purchased for cancellation at an average price of $44.61.

On January 21, 2002, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange, beginning January 23, 2002 and ending January 22, 2003, to purchase for cancellation up to 6,060,180 common shares of the Company, being 5 per cent of the 121,203,603 common shares of the Company outstanding on January 18, 2002. No common shares have been purchased for cancellation as at the date hereof.

DIVIDEND HISTORY

Prior to 2001, dividends had not been paid on the common shares of the Company. On January 17, 2001 the Board of Directors approved a dividend policy for the payment of a regular quarterly dividend of $0.10 per common share. On February 25, 2002 the Board of Directors approved an increase in the quarterly dividend to $0.125 per common share commencing with the dividend payable April 1, 2002. These dividends are payable in January, April, July and October of each year. The dividend policy of the Company continues to be under periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time.

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company are set forth below.

Name	Position Presently Held	Principal Occupation During Past 5 Years
N. Murray Edwards (1)(2)(3) Calgary, Alberta	Director	President, Edco Financial Holdings Ltd. (a private investment and consulting company). Has served continuously as a director of the Company since September 1988.
James T. Grenon (1)(2) Calgary, Alberta	Director	Managing Director, TOM Capital Associates Inc. (a private investment company). Has served continuously as a director of the Company since September 1988.
John G. Langille Calgary, Alberta	President and Director	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Keith A.J. MacPhail (3) Calgary, Alberta	Director	Chairman and President, Bonavista Petroleum Ltd. since November 1997; prior thereto Officer of the Company. Has served continuously as a director of the Company since October 1993.
Allan P. Markin (1) Calgary, Alberta	Chairman and Director	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
James S. Palmer, C.M., Q.C.(2)(3) Calgary, Alberta	Director	Chairman, Burnet, Duckworth & Palmer LLP (Barristers & Solicitors). Has served continuously as a director of the Company since May 1997.
Dr. Eldon R. Smith, M.D.(3) Calgary, Alberta	Director	Professor and Former Dean, Faculty of Medicine, The University of Calgary. Has served continuously as a director of the Company since May 1997.
Brian L. Illing Calgary, Alberta	Executive Vice-President, Exploration	Officer of the Company
Steve W. Laut Calgary, Alberta	Executive Vice-President, Operations	Officer of the Company

Name	Position Presently Held	Principal Occupation During Past 5 Years
Allen M. Knight Calgary, Alberta	Senior Vice-President, International & Corporate Development	Officer of the Company
Tim S. McKay Calgary, Alberta	Senior Vice-President, North America Operations	Officer of the Company since September 1996.
Douglas A. Proll Calgary, Alberta	Vice-President, Finance	Officer of the Company since April 2001; prior thereto Vice President Finance and Treasurer of Renaissance Energy Ltd. until August 2000 and most recently Vice President Finance and Business Development of Husky Energy Inc. from August 2000 to February 2001.
William Clapperton	Vice-President, Regulatory, Stakeholder and Environmental Affairs	Officer of the Company since January 2002; prior thereto Manager, Surface Land and Environment for the Company.
Réal M. Cusson Calgary, Alberta	Vice-President, Marketing	Officer of the Company
Réal J. H. Doucet Calgary, Alberta	Vice-President, Oil Sands	Officer of the Company since October 2000; prior thereto director of various divisions at Suncor Inc. since 1993.
Lyle G. Stevens Calgary, Alberta	Vice-President, Exploitation	Officer of the Company since October, 1997; prior thereto Manager, Exploitation of the Company since June, 1996;
Gordon M. Adams Calgary, Alberta	Secretary	Partner, Parlee McLaws (Barristers and Solicitors)
Bruce E. McGrath Calgary, Alberta	Assistant Secretary	Officer of the Company

(1) Member of the Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Reserve Committee

All directors stand for election at each Annual General Meeting of CNRL shareholders. All of the current directors and two new nominees, Ambassador Gordon D. Giffin and David A. Tuer, are standing for election at the 2001 Annual General Meeting of shareholders scheduled for May 9, 2002.

There are potential conflicts of interest to which the directors and officers of the Corporation may become subject to in connection with the operations of the Corporation. Some of the directors and officers have been and will continue to be engaged in the identification and evaluation of businesses and assets with a view to potential acquisition of interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. Conflicts, if any, will be subject to the procedures and remedies under the *Business Corporations Act* (Alberta).

As at December 31, 2001, the directors and senior officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 6 percent of the total outstanding common shares (approximately 8 percent after the exercise of options pursuant to the Company's stock option plan).

ADDITIONAL INFORMATION

Additional information including Directors' and Executive Officers' remuneration, principal holders of The Company's securities, options to purchase The Company's securities and interest of insiders in material transactions is contained in The Company's Notice of Annual General Meeting and Information Circular dated March 29, 2002 in connection with the Annual General Meeting of Shareholders of CNRL to be held on May 9, 2002 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's Management Discussion and Analysis and comparative Consolidated Financial Statements for the most recently completed fiscal year ended December 31, 2001 found on pages 41 to 51 and 52 to 71 respectively, of the 2001 Annual Report to the Shareholders, which information is incorporated herein by reference.

The Company shall provide to any person, upon request to the Secretary of the Company:

(a) when securities of The Company are in the course of distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

  (i) one copy of the Annual Information Form of The Company, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form,

  (ii) one copy of the comparative consolidated financial statements of The Company for its most recently completed financial year together with the accompanying report of the auditor and one copy of any interim consolidated financial statements of the issuer subsequent to the consolidated financial statements for its most recently completed financial year,

  (iii) one copy of the information circular of The Company in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that information circular, as appropriate, and

  (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided The Company may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the issuer.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Corporate Secretary of the Corporation at:
2500, 855 – 2nd Street S.W.
Calgary, Alberta T2P 4J8