ENCANA CORPORATION 2003 ANNUAL REPORT TO SHAREHOLDERS

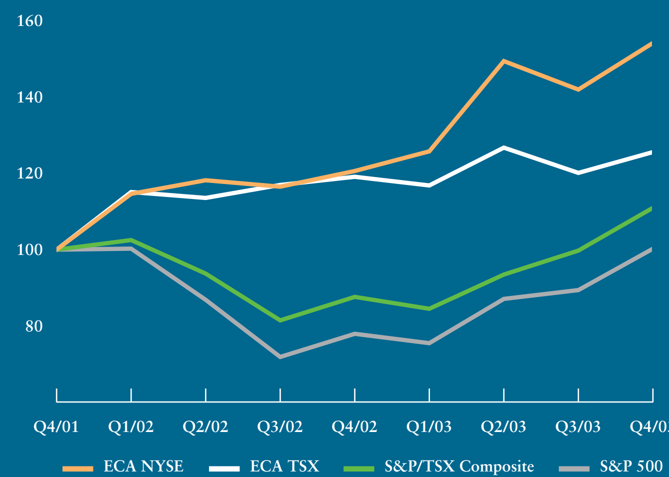
What Matters

EnCana™

CONTENTS

ENCANA TOTAL RETURN VS. MAJOR INDICES

(December 31, 2001 = 100)



U.S. DOLLAR AND U.S. PROTOCOL REPORTING

Starting with year-end 2003, EnCana is reporting its financial and operating results following U.S. protocols in order to facilitate a more direct comparison to other North American upstream exploration and development companies. Financial results are reported in U.S. dollars and operating results, namely production and reserves, are reported on an after-royalties basis. See page 47 for a more detailed Note Regarding Reserves Data and Other Oil and Gas Information.

ADVISORY

Certain information regarding the Company and its subsidiaries set forth in this document, including management's assessment of the Company's future plans and operations, may constitute "forward-looking statements" under applicable securities laws and necessarily involve risks and uncertainties associated with future events. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. See page 46 for a more detailed Note.

For convenience, references in this Annual Report to "EnCana", the "Company" or the "company", may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (each a "Subsidiary" or if more than one, "Subsidiaries") and the assets, activities and initiatives thereof. References to financial results of operations refer to the consolidated financial results of EnCana Corporation and its Subsidiaries, taken as a whole, except where otherwise noted or the context otherwise implies.

This Annual Report contains references to measures commonly referred to as non-GAAP measures. Additional disclosure relating to these measures is set forth in Management's Discussion and Analysis on pages 51, 52 and 61 of this Annual Report.

UPSTREAM

EnCana's key competitive advantages include: a vast and abundant asset base; leading technical competencies; low operating costs; low royalties; high working interest and well-developed infrastructure.

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RESOURCE PLAY

These unconventional plays form the foundation of EnCana's low-risk, predictable and profitable production and reserves growth. Making up about 60 percent of current North American production, these plays are expected to contribute about 80 percent of the company's North American production by year-end 2007.

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RESERVES

Employing the most rigorous practices in its reserves assessment is an EnCana hallmark. Each year, 100 percent of its reserves are evaluated by independent qualified reserve evaluators right from the fundamental geological and engineering data.

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CORPORATE RESPONSIBILITY

EnCana's reputation is critical to the creation of long-term shareholder value. The company's success on the bottom line is reinforced by its behaviour beyond the bottom line.

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FINANCIALS

In its financial disclosure, EnCana strives to achieve a level of transparency and clarity among the best in its industry. The financial statements have been presented in U.S. dollars. Reserves quantities and production volumes are presented on an after-royalties basis.

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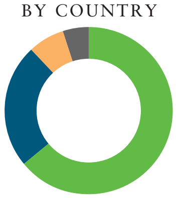
Growth & Returns Matter

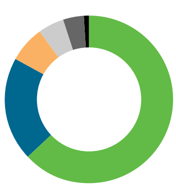
PROFILE

2003 YEAR-END PROVED RESERVES BY COUNTRY



- 64% Canada
- 24% U.S.A.
- 7% Ecuador
- 5% U.K.

2003 CAPITAL INVESTMENT



- 63% Canada
- 20% U.S.A.
- 7% Ecuador
- 5% Midstream & Marketing
- 4% U.K.
- 1% Other Countries

2003 SALES BY COUNTRY

SALES IN NORTH AMERICA 91%

=

74%

WESTERN CANADA
Over two-thirds of Western Canada sales are natural gas

+

17%

U.S.A.
Gas sales grow by nearly 50%

2%

U.K.
First oil expected from Buzzard development in late 2006

+

7%

ECUADOR
New pipeline helps double daily oil sales

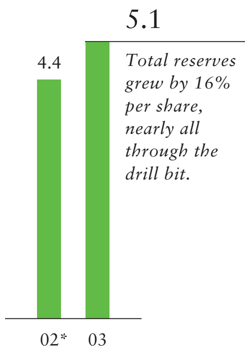
=

9%

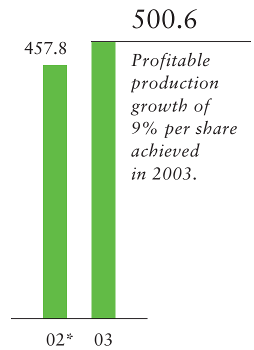
INTERNATIONAL SALES

EnCana is one of the world's leading independent oil and gas companies and North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are located in North America. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. Through its U.S. subsidiaries, EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deep water Gulf of Mexico. International subsidiaries operate two key high potential international growth regions: Ecuador, where it is the largest private sector oil producer, and the U.K., where it is the operator of a large oil discovery. EnCana and its subsidiaries also conduct high upside potential new ventures exploration in other parts of the world. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

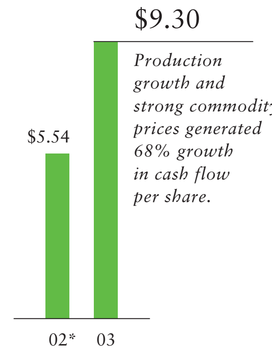
RESERVES PER SHARE
(Year-end, BOE)



SALES PER 1,000 SHARES
(BOE)



CASH FLOW PER SHARE
(US$)



US$ millions, except per share amounts

FINANCIAL HIGHLIGHTS	2003	2002*	% Change
Cash Flow	**4,459**	2,664	67
Per Share – basic	**9.41**	5.62	67
Per Share – diluted	**9.30**	5.54	68
Net Earnings	**2,360**	833	183
Per Share – basic	**4.98**	1.76	183
Per Share – diluted	**4.92**	1.73	184
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt issued in Canada (after-tax) and tax rate change gain	**1,375**	697	97
Per Share – diluted	**2.87**	1.45	98
Upstream Capital Investment	**4,939**	3,410	
Midstream & Marketing and Corporate Capital Investment	**383**	97	
Divestitures (including Discontinued Operations)	**(1,900)**	(273)	
Net Capital Investment	**3,422**	3,234	
Debt-to-Capitalization Ratio	**34:66**	31:69	
Debt-to-EBITDA *(times)*	**1.3**	1.0	
Return on Capital Employed *(%)*	**17**	8	
Return on Common Equity *(%)*	**24**	9	

OPERATING HIGHLIGHTS	2003	2002*	% Change
Natural Gas Sales *(MMcf/d)*			
Canada	**1,965**	1,975	-1
U.S.A.	**588**	395	49
U.K.	**13**	10	30
	2,566	2,380	8
Oil and NGLs Sales *(bbls/d)*			
Canada	**156,604**	143,465	9
U.S.A.	**9,291**	7,019	32
U.K.	**10,128**	10,528	-4
Ecuador	**46,521**	36,591	27
	222,544	197,603	13
Total Gas, Oil and NGLs Sales *(BOE/d)*	**650,211**	594,270	9
Net Reserves Additions *(MMBOE)*	**482**	358	
Production Replacement *(%)*	**203**	171	
Finding, Development & Acquisition Costs *($/BOE)*	**8.75**	7.95	

* *Note: All of the above information excludes Syncrude. 2002 financial and operating information is presented on a pro forma basis as if the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd. had occurred at the beginning of 2002 and is unaudited.*

Chief Executive Officer's Message

TAKING STOCK OF WHAT MATTERS

"Our second year of operation saw a sharpening of strategic focus on assets and opportunities where EnCana has clear competitive advantage."

GWYN MORGAN

TO FELLOW SHAREHOLDERS

THIS MARKS ENCANA'S SECOND ANNUAL REPORT TO SHAREHOLDERS AND A SECOND YEAR OF STRONG OPERATING AND FINANCIAL RESULTS. OUR REPORT THEME THIS YEAR IS "WHAT MATTERS".

OBVIOUSLY RESULTS MATTER. IN 2003, YOUR COMPANY'S EARNINGS INCREASED 97 PERCENT TO $1.4 BILLION, EXCLUDING THE IMPACT OF TAX RATE CHANGE AND FOREIGN EXCHANGE GAINS, COMPARED TO 2002 PRO FORMA RESULTS. CASH FLOW INCREASED 67 PERCENT TO $4.5 BILLION, OR $9.30 PER SHARE DILUTED. OPERATIONALLY, ENCANA ACHIEVED 9 PERCENT GROWTH IN OIL AND NATURAL GAS SALES, SELLING 650,200 BARRELS OF OIL EQUIVALENT PER DAY AND INCREASED PROVED RESERVES BY 12 PERCENT. CLEARLY, 2003 OPERATING PERFORMANCE IS CONSISTENT WITH OUR OBJECTIVE OF DELIVERING HIGH PERFORMANCE BENCHMARK RESULTS.

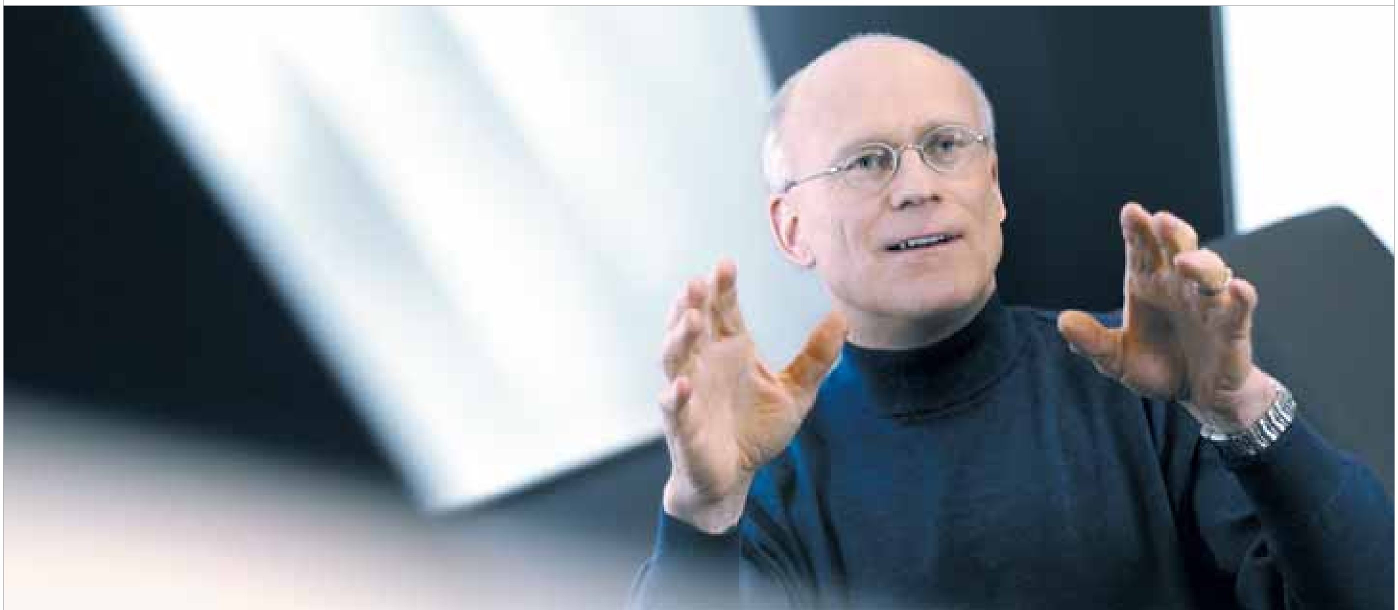
Underlying this performance are the cornerstones upon which we strive to build consistent per share intrinsic asset value growth, year after year. In this letter, I will concentrate on the cornerstones that we believe matter most for achieving growth and returns:

A CLEAR BUSINESS PLAN
focused on areas of key competitive advantage

QUALITY ASSETS
containing long-term, low-risk, strong-return growth opportunities

MARGIN ADVANTAGE *as a low-cost producer*

LOW-RISK PROFILE
including country risk, reserve risk and operational risk



GWYN MORGAN

President & Chief Executive Officer

DISCIPLINE *in applying realistically-risked return criteria for investment and divestment*

FINANCIAL STRENGTH *and flexibility in a range of commodity price scenarios*

A TRACK RECORD *of performance*

REPUTATION *for integrity and principled behavior in all we do*

ALIGNMENT *of shareholder and employee interests*

Here is the essence of each one of these cornerstones at EnCana:

A CLEAR BUSINESS PLAN *focused on areas of key competitive advantage.* Our second year of operation saw a sharpening of strategic focus on assets and opportunities where EnCana has clear competitive advantage. Our advantage resides in our large resource holdings where we can apply capital, creativity and core competencies to continuously add reserves, grow production and lower costs.

The company's future is anchored in its extensive North American natural gas assets. In recent years, it has become clear that conventional North American gas fields have entered a high-decline, high-replacement-cost era. In sharp contrast, EnCana has built an asset base focused on unconventional properties – characterized by tightly-packed gas-charged sandstones, silts and coals where resources in place are huge and production life is much longer than conventional reservoirs. Our teams have formed a unique technical and operational culture that has continuously improved our ability to locate, unlock and profit from unconventional gas reservoirs. We call them resource plays and they are now widely recognized as the future of North America gas production.

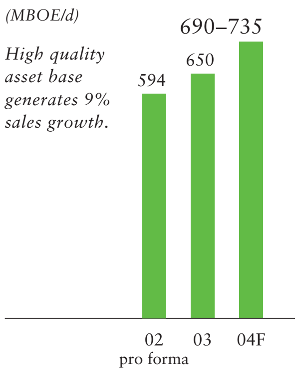
This era of declining conventional natural gas production has just begun, but it occurred 30 years earlier in conventional oil fields. In the early 1970s, North American conventional oil production peaked and began to enter a long-term decline phase. Since then, the only significant new onshore North America oil production has come from unconventional resources – the Alberta oilsands, an oil resource play. From a production point of view, there are two categories of oilsands recovery, mining projects and in-situ methods. Deposits close to the surface are accessed through mining mega projects. In 2003, we exited that business with the sale of our interest in the Syncrude mining project to focus on our 100 percent owned deeper oilsands reservoirs which require in-situ, or in-place, recovery methods. Here EnCana is successfully employing a new generation in-situ technology – steam-assisted gravity drainage (SAGD), which involves sophisticated horizontal drilling and thermal stimulation to extract the oil. These short-lead-time, lower-risk projects combine industry-leading technical know-how with continuous learning to progressively improve performance over time.

Our North American business plan capitalizes on our competitive advantage in resource plays in pursuit of being the highest internal growth, lowest unit cost producer.

TOTAL SALES

(MBOE/d)

High quality asset base generates 9% sales growth.



As I mentioned, North American conventional gas fields appear to have entered the decline phase of their life cycle. EnCana's huge unconventional natural gas resource play land base and expertise, built over decades, places us in an advantageous position. Our long-term gas growth is anchored by a multi-year drilling portfolio on our existing land base. Currently, about 60 percent of our North America production comes from resource plays. By year-end 2007, we expect it to be 80 percent.

In a nutshell, our North American business plan capitalizes on our competitive advantage in resource plays in pursuit of being the highest internal growth, lowest unit cost producer of natural gas and oil among our large capitalization peers.

The balance of EnCana's upstream strategy focuses on overseas and offshore oil exploration and production. The key growth anchor is the U.K. central North Sea where we are developing the Buzzard oil discovery. In Ecuador, substantial growth and value creation occurred during 2003 with the completion of the OCP Pipeline, allowing us to double production late in the year. Participation in a major discovery in the deep water Gulf of Mexico adds to our future oil growth outlook and we are striving to find the best plan for meeting our return criteria for development of our Deep Panuke gas discovery off Nova Scotia.

Our North America, U.K. and Ecuador regions contain clearly-visible, strong-return, growth projects which we estimate are capable of building reserves and production by an average of 10 percent per share per year for at least five years. Very importantly, EnCana does not need to find or acquire any new resources to meet this strong internal growth outlook. Adding further upside, we continue to have an active exploration program in these regions, where we drilled more than 600 net exploration wells in 2003. Beyond that, we have sharpened the focus of our international new ventures exploration program to countries where we have prospects offering significant upside potential. Our strategic plan calls for exploration outside existing core areas to be approximately 1 percent of our capital budget in 2004.

QUALITY ASSETS *containing long-term, low-risk, strong-return growth opportunities.* Every corporation is only as strong as the foundation upon which it is built. For our company, which has been building its asset base over several decades, each investment decision either strengthens or weakens the future. Over the many years that my senior management team and I have worked together, we have followed some clear and simple principles. Rather than focusing on short-term production spurts, which are typical in our business, we have built very large, wholly-owned land positions containing resources in which we invest capital, technology and experience to continually build production and reserves while driving down costs. Assets that didn't meet the criteria were steadily divested; assets that did were steadily added. In addition to our huge legacy assets on the Palliser and Suffield blocks in Alberta, EnCana has acquired high-quality North American resource plays at Greater Sierra and Cutbank Ridge in British Columbia, and Jonah and Mamm Creek in the U.S. Rockies. This has resulted in a leading onshore North American land position of 17 million acres of undeveloped land mainly in resource plays that contain long-life, low-risk, repeatable exploitation opportunities plus large unbooked resource potential. We unlock these reserves and production by employing a process of long-term, continuous learning called Resource Play Management. Randy Eresman, our Chief Operating Officer, describes this more fully in his letter and a vivid depiction is shown on the page 19 fold-out. For shareholders, it means that EnCana's existing North American asset base has the capability of strong reserves and production growth for many years to come.

MARGIN ADVANTAGE *as a low-cost producer.* Given our large contiguous land positions, we are able to operate large scale manufacturing-type programs that help us drive down costs. We focus on sweet natural gas to reduce operational complexity. As well, given the long-life nature of our resource play assets, we have opportunities to learn and apply technology to further drive down costs and improve recoveries. Our significant position in the industry and the economies of scale of our programs enable us to work with suppliers to innovate and improve returns – for both of us. For example, in our core operations in southern Alberta, the efficiencies our teams have brought to the business have helped us keep the costs of drilling a single well at a similar level for more than 20 years. This kind of efficiency also means that EnCana's operating and administrative cost performance today ranks among the best in our peer group.

In our core operations in southern Alberta, the efficiencies our teams have brought to the business have helped us keep the costs of drilling a single well at a similar level for more than 20 years.

LOW-RISK PROFILE *including country risk, reserve risk and operational risk.* I believe that investors in general pay too little attention to a company's risk profile.

In an increasingly complex and uncertain world, it is significant that 90 percent of EnCana's reserves and production are in North America. Our current projections show that in five years, country risk will be equally low with approximately 90 percent of our reserves and production in North America and the U.K. We believe EnCana's financial statements provide some of the most transparent and detailed disclosure in the corporate sector. For an oil and gas company, reliability and integrity of reserves assessment are just as important as financial disclosure. EnCana was one of the first to establish a committee of independent directors to oversee reserve evaluations and we are one of the few large oil and gas companies where all of the published reserves are the result of reports by independent qualified reserve evaluators. To be clear, these are not reserve audits or reviews. They are grassroots, detailed evaluations from base data and they are completed on all of our properties every year.

At EnCana, we regard our average 10 percent per share production growth projection as relatively low risk because it is based on the fundamental technical assessment of clearly-identified projects from assets the company now owns.

There has been a great deal of investor focus on EnCana's future production growth outlook. At EnCana, we regard our average 10 percent per share production growth projection as relatively low risk because it is based on the fundamental technical assessment of clearly-identified projects from assets the company now owns. The key thing to remember is that we believe that EnCana's current land base has more than enough unbooked resource potential to achieve our growth targets through low-risk, repeatable drilling, without any new discoveries or acquisitions. This means that in contrast to the industry, EnCana's risk is not in finding new reserves, but rather in execution of our large, repeatable, development programs to turn these resources into reserves and production. That's why one of our mantras is "keep it simple, focus and deliver."

DISCIPLINE *in applying realistically-risked return criteria for investment and divestment*. Studies of investment projects in essentially all capital intensive industries reflect a bias towards optimism at the time of project approval. Commodity prices are a big factor in profitability, but price variations tend to normalize over project life cycles. The key factor driving poor performance of many resource investments is a lack of discipline when estimating critical factors such as reserve size, capital cost and operating performance, all of which are subject to a range of uncertain outcomes. Consistent creation of shareholder value requires a disciplined approach to managing these uncertainties coupled with the application of realistic, risk-adjusted, technical and economic assessments and strong financial return criteria. The objective of this process is to select those projects with the highest probability of exceeding profitability hurdle rates. At EnCana, we strive for risk-adjusted, full-life-cycle project returns of at least 20 percent on exploitation projects and at least 15 percent on early stage exploration projects to capture new resource plays. While project lead-times necessitate a delay between capital outlay and returns, over time this discipline should result in steadily increasing normalized returns on capital and long-term sustainable intrinsic value creation. One of our biggest responsibilities to shareholders is to ensure this investment discipline is applied consistently throughout EnCana.

FINANCIAL STRENGTH *and flexibility in a range of commodity price scenarios.* In 2003, we retired 5 percent of our shares at a cost of $868 million, invested $4.5 billion in capital projects, purchased $820 million in assets, and sold $2.3 billion of assets while maintaining a debt-to-capitalization ratio among the lowest in our peer group. This reflects our philosophy of internally funding our growth, and using excess cash to further enhance per share value and results through EnCana share purchases. We also increased our dividend by 33 percent at the beginning of 2004. EnCana's $4.2 billion upstream core capital program for 2003 was about 45 percent directed at maintaining our production and reserves, meaning that about $2.6 billion of free cash flow was generated for reinvestment in growing our business.

EnCana engages in price hedging for the purpose of reducing the portion of our cash flow subject to commodity price risk, thereby increasing the likelihood of achieving target returns and ensuring our ability to comfortably fund our capital programs. As of the writing of this report, about 45 percent of our projected gas production is hedged for 2004 and 50 percent of our projected oil production is hedged for 2004.

EnCana's pension plans were essentially fully funded at year-end 2003. I also want to note that, for the first time, 2003 year-end financial statements include the expensing of stock option compensation costs.

A TRACK RECORD *of performance.* The creation of EnCana brought together two of Canada's most respected corporations, PanCanadian Energy and Alberta Energy Company, each with a long track record of shareholder value creation and corporate responsibility. In the two years since the merger, sales volumes have experienced growth of 22 percent and proved reserves have grown by 20 percent. Our continuing effort to focus on the highest quality assets has resulted in asset dispositions totalling $2.7 billion and asset acquisitions totalling $1.6 billion. The original merger capital and operating synergies totalling $365 million have been realized, with EnCana achieving top tier operating plus administrative cost performance. Our balance sheet remains strong. For shareholders who have held shares of EnCana (formerly PanCanadian) since the beginning of 2002, total return on the Toronto Stock Exchange has been 26 percent.

EnCana's shares represent approximately 40 percent of the TSX Oil and Gas Exploration and Production Index. In 2003, EnCana shares underperformed our Canadian-based peers. These companies benefited from a change in investors' outlook for oil-weighted stocks, driving an increase in their price to cash flow multiples, which had been low relative to gas-weighted stocks such as EnCana. Nevertheless, as of the writing of this report, EnCana's share price multiple remains above our Canadian peers and in the top three of our North American peer group.

For our U.S. investors, who make up about half of our shareholder base, the total shareholder return in 2003 on the New York Stock Exchange was 28 percent, with the difference reflected in the strong appreciation of the Canadian dollar. EnCana shares outperformed our U.S.-based peer group.

We strive for risk-adjusted, full-life-cycle project returns of at least 20 percent on exploitation projects and at least 15 percent on early stage exploration projects.

REPUTATION *for integrity and principled behavior in all we do.* I am especially proud to report that 2003 saw the completion and launch of a unique foundation project for EnCana – our Corporate Constitution. The Board of Directors resolution approving our Constitution states, in part, that it "will set out the foundation upon which we will build a high performance principled corporation." Flowing out of the Corporate Constitution was EnCana's Corporate Responsibility Policy. Both documents define the principles and behaviours that stakeholders can expect from EnCana and its people. They are posted on www.encana.com and are discussed in greater detail in the Corporate Responsibility section of this report on pages 36 to 41.

ALIGNMENT *of shareholder and employee interests.* Executive and employee compensation has been in the spotlight recently. Like many items in our world, the problems have developed most often as the result of excesses in implementation, rather than the basic principle involved. For example, stock options which are too large or too concentrated at the top of companies may drive short-term thinking. In my decade as a Chief Executive Officer, we have distributed stock options to essentially every employee, meaning a lower degree of concentration at the top. The fact that a lot of shareholder value was created over that decade and that our asset base is characterized by low-decline, long-life assets, certainly belies the short-term thinking issue. EnCana also has an employee savings plan where employees accumulate share ownership, and a significant portion of our annual High Performance Results Awards is tied to overall corporate performance and paid in EnCana shares. Effective January 1, 2004, EnCana's Board approved a plan that replaces approximately half of future share option grants with performance share units. In order for any payout to occur under these share units, EnCana's total shareholder return over a three-year period must be at least at the median of our North American peer group, with further upside as our performance moves to the top of our peer group. I believe these long-term incentives provide alignment with shareholder interests which, applied with care and diligence, will continue to help drive EnCana's operating performance over the long term.

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U.S. Protocol Reporting EnCana is a proud and strong Canadian-headquartered international corporation. Shares are traded on the Toronto and New York stock exchanges. An increasing number of our shareholders are international and, as a leading North American based independent, we are followed by a broad suite of domestic and international investment analysts. Most of our peer group is U.S. based. Since the formation of EnCana, it has become increasingly clear that reporting in different currency, production and reserves protocols than our U.S. competitors causes confusion and makes comparisons difficult. So for the first time, this annual report is published in U.S. dollars and production and reserves are reported after royalties. Today, more than 15 of Canada's largest companies report in U.S. dollars with the same objective – having the full value of their shares recognized in international investment markets.

Commodity Outlook World oil prices are impacted by a myriad of factors, but Asian demand growth, combined with political and social turmoil in some producing countries, has eroded worldwide spare capacity to only 3 percent of production. On top of that, the U.S. dollar has fallen by about 20 percent against most world currencies. This means that it takes $30 per barrel to yield the same real revenue for producing countries as $25 per barrel did in the past. Overall, we appear to have moved into an era of generally stronger US$ oil prices. Turning to natural gas prices, North American conventional gas supply seems to have peaked and entered the early stages of decline. There is very little prospect of significantly increased natural gas supply from offshore liquefied natural gas or Arctic sources prior to 2008 or 2009. This means that North America will have to get along with the current gas supply or less, signaling a strong and most likely volatile natural gas pricing environment.

North America will have to get along with the current gas supply or less, signaling a strong and most likely volatile natural gas pricing environment.

CONCLUSION 2003 was another year of change for the people of EnCana. Gerry Macey, President, Offshore & New Ventures Exploration, announced his retirement after a career marked by major exploration successes and we thank him for his contribution. Randy Eresman was appointed Chief Operating Officer, reflecting his lengthy and outstanding track record of disciplined value creation. The consolidation of our upstream business under Randy, and the sharpening of our strategic focus resulted in further reorganization, particularly in our offshore units. As in our merger year, EnCanans pulled together, accomplished their objectives and delivered on our promises to shareholders. The following reports by EnCana's leaders clearly illustrate the dedication, creativity and pursuit of excellence throughout our company. We welcomed Jane Peverett and Ralph Cunningham, two experienced leaders in the North American energy sector, to our Board of Directors. As the senior representative of EnCana's Executive Team, I want shareholders to know that your independent Board of Directors provided top flight governance, sound advice, strategic perspective and dedication, as we continued to pursue our vision – building the world's high performance benchmark oil and gas company.

GWYN MORGAN

President & Chief Executive Officer

February 26, 2004

17 Million
net acres of land
onshore North America

Two time
Production
Replacement

Average
10%
10%
10%

per share
production growth

1 Billion Barrels Oil Reserves

s

8.4

Gas Reserves

TCF

Stakeholder Engagement

Focus

Delivering
Growth &
Returns

Chief Operating Officer's Message

FOCUS AND DISCIPLINE MATTERS

"To fully appreciate EnCana's potential, one needs to understand resource plays and why we believe we can deliver both strong growth and returns by focusing on them."

RANDY ERESMAN

TO FELLOW SHAREHOLDERS

IT IS A PLEASURE TO HAVE THE OPPORTUNITY TO ADDRESS SHAREHOLDERS AFTER COMPLETING ONE YEAR AS CHIEF OPERATING OFFICER. 2003 WAS A YEAR OF TRANSITION FOR ENCANA – ONE THAT WE BELIEVE SETS US ON AN EVEN STRONGER FOOTING TO CREATE VALUE IN THE YEARS AHEAD. AS GWYN NOTED IN HIS CEO'S LETTER, WE SHARPENED OUR STRATEGIC FOCUS ON ASSETS WHERE WE BELIEVE WE HAVE A CLEAR AND NATURAL COMPETITIVE ADVANTAGE – NORTH AMERICAN RESOURCE PLAYS. TO FULLY APPRECIATE ENCANA'S POTENTIAL, ONE NEEDS TO UNDERSTAND THEM.

The resource play concept is not new to EnCana. Yet it's relatively recently that we have coined the term to describe what our predecessor companies were mainly built upon. From the middle of the last century, we have developed and grown our legacy assets in southeast Alberta on the Palliser and Suffield blocks. These expansive and abundant properties have provided predictable, reliable and profitable reserves and production growth for more than four decades. And they are expected to continue to do so well into the future. In more recent years, we have leveraged our well developed knowledge of these unconventional Alberta plays by building leading positions in the U.S. Rockies at Jonah and Mamm Creek; northeast British Columbia at Greater Sierra and Cutbank Ridge; and our oilsands at Foster Creek and Christina Lake in northeast Alberta. Today, these unconventional plays – these resource plays – provide over half of our current production, and represent the prime source of our future growth.

But you may ask what is so special about resource plays? There's plenty. Resource plays are highly concentrated occurrences of hydrocarbons, either areally over great expanses of land or vertically in thick sections of the earth's crust. Once identified, they have low geological and commercial development risk. And they have the potential to make a material impact because of their size and low, steady-state decline rates. The appropriate application of technology and program execution are keys to unlocking value

RANDY ERESMAN

Chief Operating Officer

from resource plays. Resource play developments occur over long periods of time, well by well, in large-scale developments that repeat common tasks in an assembly-line fashion and capture economies of scale to drive down costs. Unlike most conventional exploration and development, resource plays are relatively predictable in timing, costs, production rates and reserve additions and can provide steady long-term reserves and production growth. Furthermore, unit development and operating costs usually decrease with time. These characteristics stand in sharp contrast with most conventional oil and gas plays – where well decline rates accelerate and unit operating and reserve replacement costs increase as North American conventional discoveries become smaller and riskier. As such, the risks associated with EnCana's resource plays are known to be far lower than much of the industry's activity conducted to date.

To most effectively find and develop these distinct hydrocarbon play types, we have developed what we call our Resource Play Management System (RPMS), a disciplined process aimed at capturing the greatest value from each resource. The system entails identification of the potential resource, creative application of technology to unlock the resource, pilot testing to prove commerciality, large-scale strategic land acquisition, external stakeholder engagement and preparation of a long-term drilling and infrastructure plan. Our RPMS focuses on delivering profitable growth with relatively little geologic risk, and controlling our costs by managing our large-scale programs in a repeatable manufacturing style. We bring flexibility, simplicity and consistent standards to our work. We've found that as field development expands, learning emerges, innovation drives costs down and production goes up, continuously increasing return on investment. Every resource play has these same efficiency attributes and common life-cycle characteristics.

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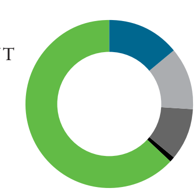
LOW RISK CAPITAL INVESTMENT PROFILE
2004 Forecast



- *63% Gas Exploitation*
- *14% Oil Exploitation*
- *12% Long-term Projects*
- *10% Core Area Exploration*
- *1% New Ventures Exploration*

In all of our resource plays, a large known resource had existed prior to us capturing the play. In fact, much of our current resource play lands were initially explored and identified by other oil and gas companies. Immature or inappropriate technologies produced poor results and subsequently the plays were largely ignored or abandoned in favour of conventional plays.

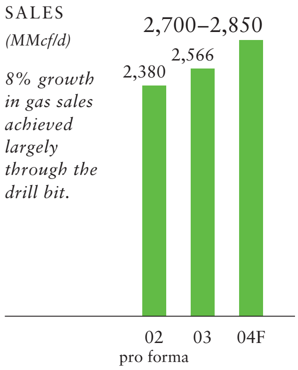
But today, technological innovation has become a key driver in unlocking the economic potential of these same resource plays, each with its own unique technical parameters. By cracking the nut technologically and piloting these advances, we are able to prove that the resource can be produced commercially. In general, advances in drilling, well completion and geophysical technologies have benefited the industry. But we've taken these advances even further. Coil-tubing drilling of shallow gas in Alberta; horizontal under-balanced drilling in northeast B.C.; multi-stage fracturing and micro-seismic in our deep, tight-gas plays in the U.S.; and four-dimensional seismic and steam-assisted gravity drainage in our oilsands operations have all contributed to capturing a resource that would still be locked in the ground had new technologies not been developed and implemented.

Once we determine the best technology to apply to the resource, we conduct a stealth-like land assembly to capture the land overlying it.

Once we determine the best technology to apply to the resource, we conduct a stealth-like land assembly to capture the land overlying it. Through land sales, acquisitions and swaps, we acquire large, contiguous tracts of land. Recent examples of this strategy include the capture of the Cutbank Ridge resource play in northeast British Columbia. We analyzed well data from more than 300 existing wells and drilled 25 exploration wells in order to test the productive capability of the reservoir as well as to test our dual-leg horizontal drilling technology. From this analysis, we believed that the Cadomin formation held tremendous resource potential. Using EnCana's financial capacity to our advantage, we were able to lock up huge land blocks covering about 500,000 net acres through private transactions and Crown land sales. Our success in securing this play allows us to capture an estimated 6 trillion cubic feet of original gas in place. And we are continuing to look for new resource plays as evidenced by the more than 600 net exploration wells drilled in 2003. Such a significant program is highly focused on rounding up a large resource rather than hoping for single-well exploration success, which often characterizes conventional exploration.

TOTAL GAS SALES
(MMcf/d)

8% growth in gas sales achieved largely through the drill bit.



But we can't successfully carry out these large focused development programs without the support of our stakeholders. Through regular dialogue with regulators, land owners, community representatives and aboriginal groups, we strive to work cooperatively towards meeting our common goals. Engaging our stakeholders early and often is key to minimizing execution risks associated with our developments.

At EnCana, looking back and learning is not an option, it is critical to our future success. The great advantage of resource plays is that they present huge opportunities to learn and apply technological advancements because the development programs, by their nature, are conducted over many years. These learnings produce innovative approaches that reduce costs and continually improve economics. This contrasts sharply with conventional plays where major development decisions must be made prior to first production, making risk management more art than science. The Jonah field in Wyoming is an example of a resource play where our constant learnings have been applied allowing us to access more and more gas resource. Today, after several years of drilling and testing new stimulation techniques, we believe we will be able to recover almost twice as much gas as we thought when we entered the Jonah field in June 2000.

That's the operating story that generates growth, but what about the economics? After all, investment returns are what really matter – building intrinsic value. Our decision to invest in any of our opportunities within our portfolio is made only after a thorough analysis of the fully-risked project economics. We will not sacrifice returns for the sake of production growth. Internal rate-of-return analysis is completed for each project with a 15 percent hurdle rate on an after-tax, fully-risked basis required for stand-alone developments or oilsands projects. For projects where historical capital has been invested, we apply a minimum 20 percent hurdle rate. We also have a cut-off for profit-to-investment ratio analysis which examines the amount of profit generated for each dollar invested, to ensure projects are profitable and not over-capitalized. We also stress test our projects against the constant commodity price that would generate a return exceeding our cost of capital after taking into consideration project specific transportation, quality differentials and hedging. We call this the project supply cost. We believe this disciplined approach, applied consistently across the portfolio, maximizes returns and balances both near- and long-term value creation.

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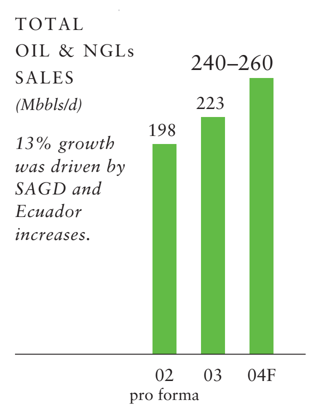


In the past year, we made a number of decisions that highlight our emphasis on intrinsic value creation. We called a regulatory time-out at our Deep Panuke gas project because the economics of the original field development plan did not meet our stringent capital investment hurdles. Additionally, we sold our interest in Syncrude for a value that, had we chosen to retain it, would have implied that we were willing to accept a rate of return below our cost of capital. Since the merger, we have sold a total of about 50,000 barrels of oil equivalent per day of upstream production at similarly strong valuations – assets that did not fit our core criteria of high working interest, long-life and low operating costs.

As we reflect on 2003, it was a year of strong operating and financial performance, largely the result of efforts of our motivated and focused teams. Executing a large, diversified program in Canada, the U.S.A., Ecuador, the U.K. and beyond takes dedicated and capable teams of people who know their business, operate safely and act environmentally responsibly, think for themselves and take educated risks in pursuit of what matters – building intrinsic value. At every level, we strive to keep things simple, focus on long-term value creation and deliver on our commitments. For that, I thank our people, our suppliers and our contractors.

RANDY ERESMAN

Chief Operating Officer

PROFILE

CANADIAN PLAINS

The Canadian Plains region combines the legacy lands of PanCanadian Energy and Alberta Energy into a regional powerhouse with 7 million net undeveloped acres, much of it in large contiguous blocks.

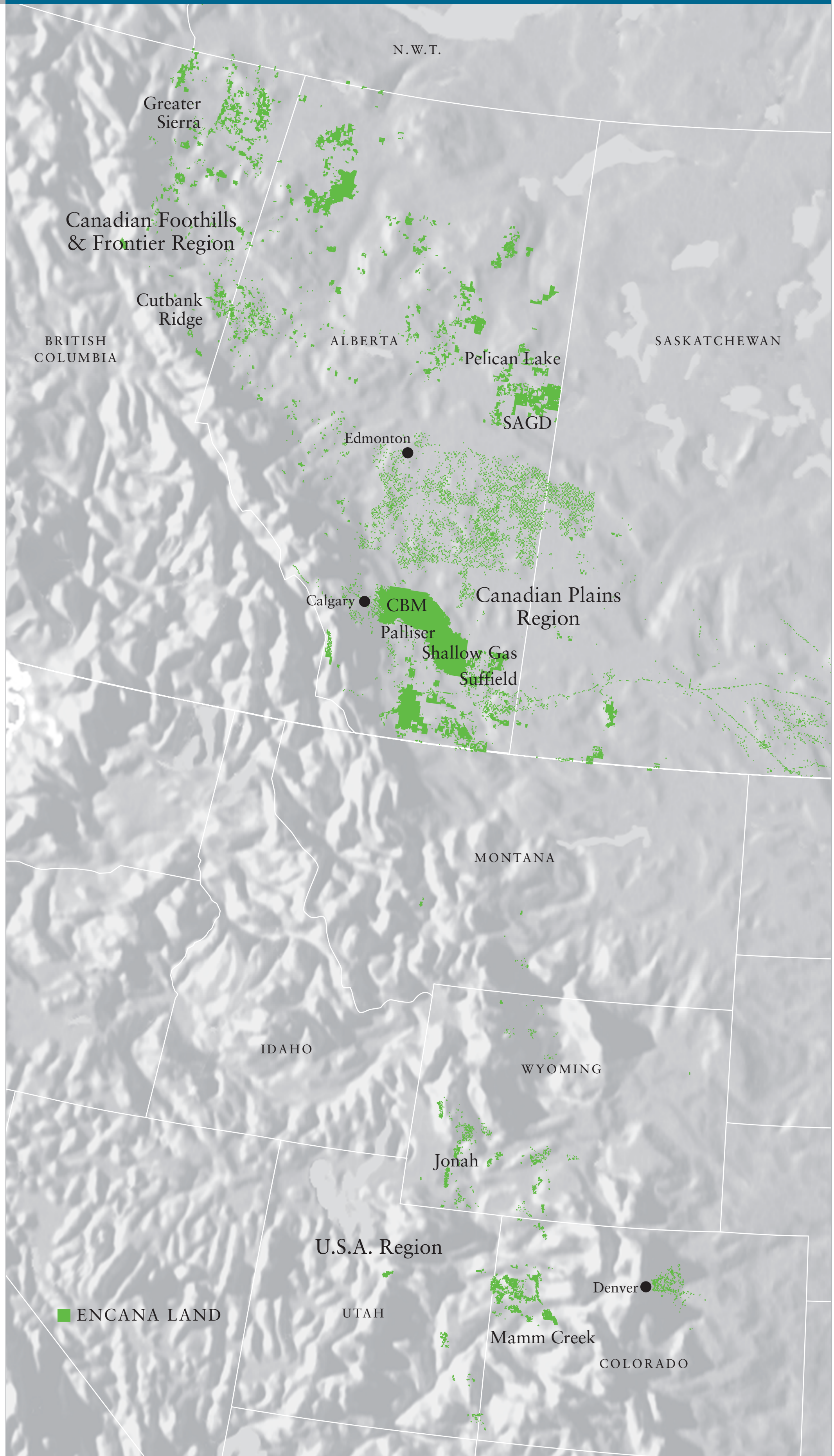
OILSANDS – CANADIAN PLAINS

EnCana's oilsands focus is on the 30 billion barrels of original oil in place on its lands in northeast Alberta. Using steam-assisted gravity drainage, the company is a leader in in-situ oilsands cost and reservoir performance.

U.S.A.

Following EnCana's entry into the U.S. Rockies in mid-2000, this deep, multi-zone, tight-gas exploitation play has become the company's highest growth area. The geology in the U.S. Rockies is characterized by sandstones with gross thickness of up to 3,000 feet.

ONSHORE NORTH AMERICA CORE AREAS



CANADIAN FOOTHILLS & FRONTIER

The Canadian Foothills & Frontier region has an undeveloped land base of 14.5 million net acres providing a strong base from which to leverage advanced core competencies in horizontal, underbalanced drilling.

U.K.

EnCana's Buzzard discovery was the largest in the U.K. central North Sea in the last decade. The project is fully sanctioned and moving towards its target first-oil date of late 2006.

ECUADOR

This South American country holds tremendous resource potential. With the opening of the OCP Pipeline in September 2003, EnCana was able to double production.

Upstream

OPERATING RESULTS MATTER

2003 RESULTS AND 2004 OUTLOOK (US$)

In 2003, EnCana invested capital of about $4,650 million adding 533 million barrels of oil equivalent of natural gas, oil and natural gas liquids reserves, before production and dispositions, at a finding, development and acquisition cost of about $8.75 per barrel of oil equivalent. The company drilled 5,632 net wells, nearly all of which were in its Western Canada and U.S. Rockies resource play regions. Total sales averaged 650,211 barrels of oil equivalent per day in 2003, 9 percent higher than the pro forma results for 2002, excluding Syncrude. Operating and administrative costs averaged $4.11 per barrel of oil equivalent.

Gas sales were 2,566 million cubic feet per day in 2003, an 8 percent increase over 2002 pro forma results. One of the inherent risks in natural gas exploitation and development in Western Canada is weather uncertainty. In 2003 Western Canada gas production growth was lower than forecast because of a shorter than expected winter drilling season in northeast B.C. and a wetter than normal spring in southeast Alberta. This impacted the company's ability to complete and tie-in all of its planned wells in the first half of 2003. In the U.S. Rockies, EnCana grew gas production by 49 percent reflecting strong drilling results in its Jonah field in Wyoming and Mamm Creek field in Colorado.

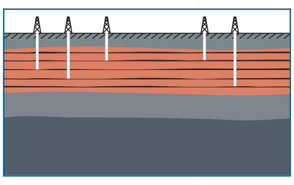
Oil and natural gas liquids sales averaged 222,544 barrels per day, a 13 percent increase over 2002 pro forma results, excluding Syncrude. A 26 percent increase in Western Canada heavy oil sales, largely from the company's Foster Creek SAGD operations, and a 27 percent increase in Ecuadorian oil sales, were the key drivers of the overall increase.

In 2004, EnCana expects barrel of oil equivalent sales volumes to increase between 6 percent and 13 percent with gas sales ranging from 2,700 to 2,850 million cubic feet per day and oil and NGLs sales ranging from 240,000 and 260,000 barrels per day. The company plans to drill about 5,000 net wells in 2004.

RESOURCE Plays Matter

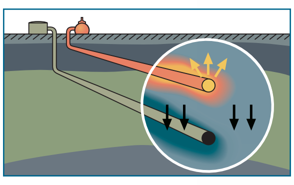
Steady, reliable and highly-profitable production growth year after year

Large, known sources of oil and gas are trapped beneath the earth's surface in what EnCana calls resource plays. The resource exists over huge areal or vertical expanses and was long considered uneconomic or a challenge technically. But by bringing together innovative technology and large scale exploitation programs, these resource plays are providing the foundation for long-term, low-risk, predictable and profitable production growth. EnCana's focus on resource plays in North America is fundamental to its target of delivering an average 10 percent per share growth in reserves and production per year for at least five years.



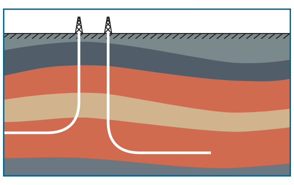
Shallow gas

Two decades of improving efficiencies in multi-zone shallow gas operations make this one of the company's most profitable and promising bases for the development of the next resource play in this region – coalbed methane.



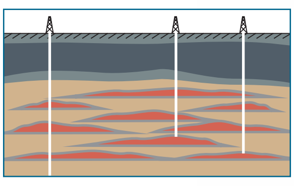
SAGD

Steam-assisted gravity drainage thermal recovery technology has unlocked EnCana's huge in-situ oilsands resource and its phased development is expected to generate long-term profitable production growth.



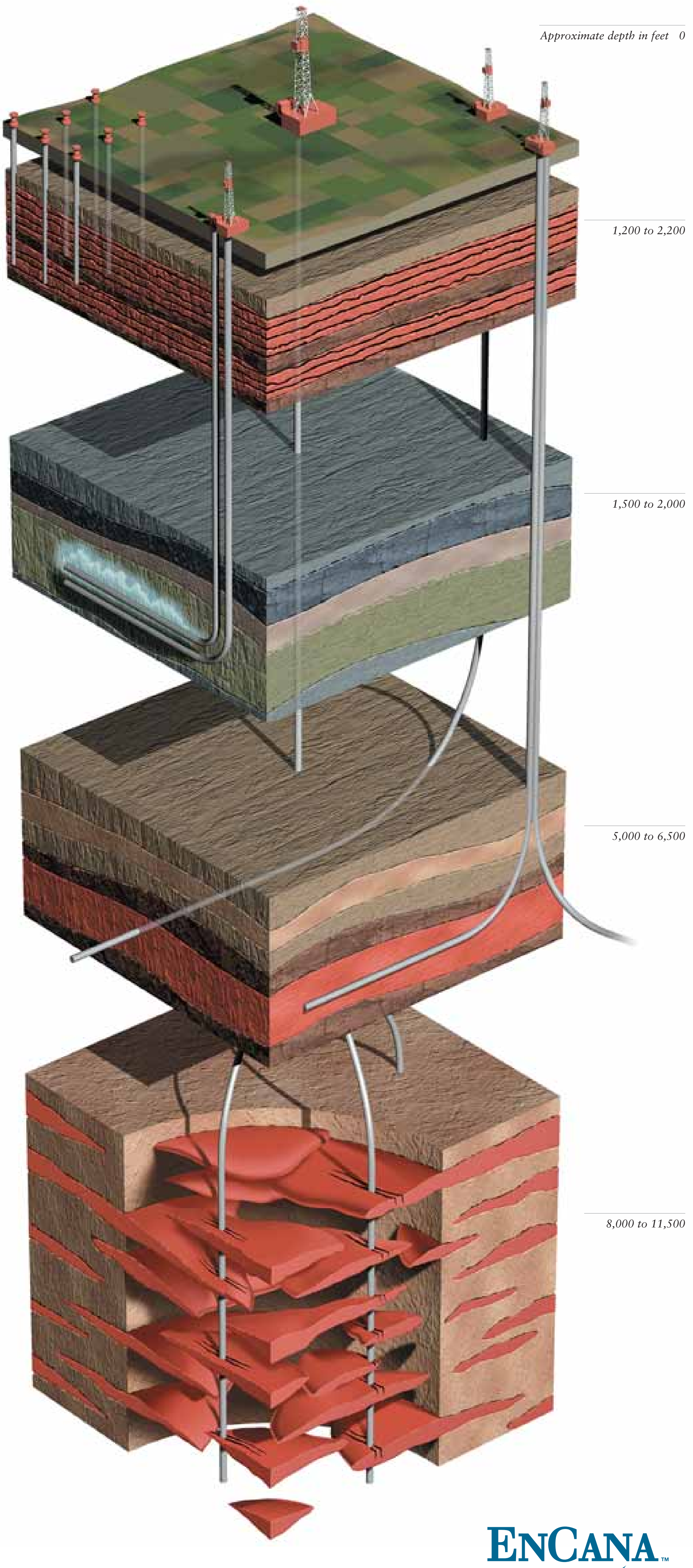
Horizontal drilling

The application of horizontal, underbalanced drilling in gas exploitation opened what is considered to be one of Canada's largest regional gas plays in the Greater Sierra region of northeast B.C.



U.S.A. tight gas

Applying innovative seismic and completion technologies in this deep, multi-zone, tight-gas region has dramatically increased reserves and driven production growth.



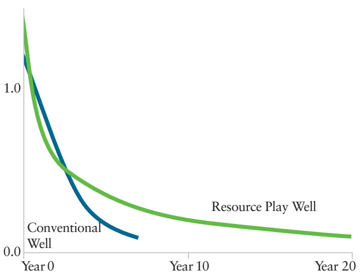
* *View EnCana's resource play animation at www.encana.com*

RESOURCE PLAY MANAGEMENT

1. *Focused exploration – you find what you look for*
2. *Pilot to prove commerciality*
3. *Assemble land*
4. *Risk mitigation – engage external stakeholders*
5. *Manufacturing-style development*
6. *Look back and learn*

PRODUCTION DECLINE COMPARISON

Conventional vs Resource
Production Rate Index



Decline Curve

A critical difference between a conventional well and a resource play well is the decline behavior. A resource play well has a steeper first year decline rate which continually decreases resulting in a long production life.

PLAYS

- SHALLOW GAS
- COALBED METHANE
- FOSTER CREEK
- PELICAN LAKE
- CUTBANK RIDGE
- GREATER SIERRA
- MAMM CREEK
- JONAH

Canadian Plains

PROGRAM EXECUTION AND EFFICIENCY MATTER

JEFF WOJAHN

President

Canadian Plains Region

PROVEN SUSTAINABILITY

Large contiguous land blocks totalling 7 million net undeveloped acres characterize Canadian Plains, where Canada's largest natural gas resource – the Medicine Hat shallow gas pool – has proven the sustainability of EnCana's huge Palliser and Suffield blocks. Coalbed methane exploitation, which can leverage EnCana's well-developed infrastructure, provides further long-term sustainable growth potential. And at EnCana's high-quality oilsands asset near Cold Lake in northeast Alberta, Foster Creek is producing more than 28,000 barrels per day, only a fraction of its potential.

SHALLOW GAS

It's a quintessential resource play – steady, reliable, sustainable production growth with continued opportunity on the horizon. EnCana's prolific shallow gas lands, covering about 3 million acres of mostly fee title lands across the southeast corner of Alberta, produced close to 700 million cubic feet of natural gas per day in 2003, a rise of 7 percent in the past year. This is a region where gas production declines rapidly in the first year of a new well, but then flattens out to continue flowing gas for decades.

Success in shallow gas development is rooted in program execution and efficiency. It starts with a deep understanding of reservoirs, developed using knowledge collected from tens of thousands of wells drilled over the past 40 years. Additional insight is obtained through pilot projects that help determine long-term reservoir and production characteristics. All the while, statistical reservoir characterization helps rank EnCana's portfolio of opportunities, as ongoing technology and process development initiatives improve cost structures, access more gas resource and minimize numerous risks. The reservoir sweet spots are identified, production profiles are predicted and project economics are well understood before the major investments are pledged towards developing the most profitable and productive regions. Based on these thorough assessments, EnCana drilled 2,400 wells in 2003. At an average rate of more than six per day, this requires comprehensive planning and military-like deployment of resources. Such a systematic approach helps ensure EnCana's shallow gas developments achieve strong project returns.

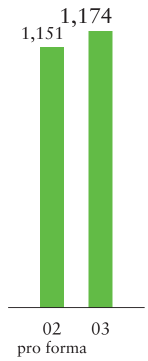
COALBED METHANE

Coal is Canada's most abundant fossil fuel, but coal also contains the principle component of natural gas – methane. In place resource estimates for coalbed methane (CBM) vary greatly, from about 150 trillion to more than 3,000 trillion cubic feet, but tell one tale: the potential is enormous. As in all resource plays, the objective is to unlock the resource potential. In 2003, EnCana turned two years of pilot evaluation work into Canada's first commercial CBM development. Following a 35-well pilot project, which produced about 3 million cubic feet per day, EnCana ramped up drilling in 2003 with another 270 wells on its fee title lands east of Calgary, taking year-end production to about 10 million cubic feet per day.

Incrementally, CBM volumes are small. Single wells produce between 30,000 and 250,000 cubic feet per day. But EnCana's multi-well projects can, over time, achieve substantial production growth. EnCana's CBM initiatives are an ideal extension of the

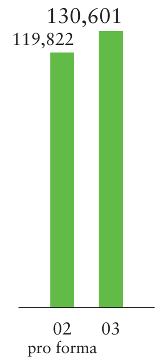
TOTAL GAS SALES
(MMcf/d)

This region has strong infill and stacked sands completion opportunities.



TOTAL OIL & NGLs SALES
(bbls/d)

Growth in oil sales has been led by SAGD at Foster Creek.



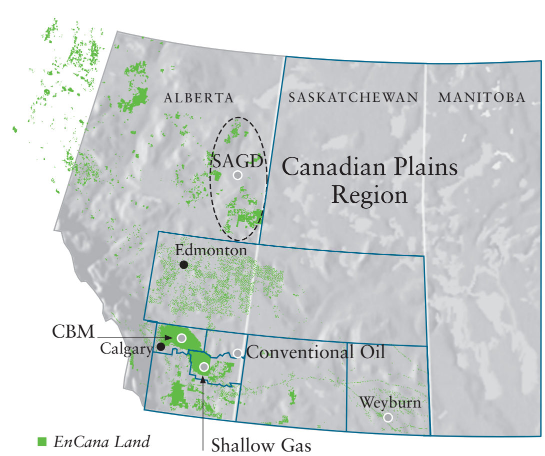
company's core competency in shallow gas development. EnCana uses the same rigs and drilling practices as shallow gas and captures significant synergies with existing multi-zone fracturing techniques. Capacity in existing compression and sales infrastructure can be utilized for CBM, reducing both development costs and cycle times. Of particularly favourable note, CBM production on EnCana's Palliser Block is essentially dry, producing less water than many shallow gas wells. In 2004, about 300 wells are planned, taking production to about 30 million cubic feet per day by year-end. Over the next five years, EnCana estimates CBM production could reach more than 200 million cubic feet per day.

OILSANDS

EnCana shifted its oilsands strategy in 2003, selling its non-operated interest in Syncrude's mining operation to focus on its 100-percent-owned in-situ (in-place) steam-assisted gravity drainage (SAGD) projects. Foster Creek, Canada's first large-scale commercial SAGD project, completed its first expansion on time and on budget, adding six new well pairs, which increased production more than 50 percent to about 28,000 barrels per day. Steam generation capacity increased with the construction of a co-generation plant that powers the SAGD facilities and sells electricity to the Alberta power grid. EnCana's other thermal oil recovery project – Christina Lake in northeast Alberta – is producing about 5,000 barrels per day from four well pairs. EnCana has achieved an industry leading steam-oil ratio, requiring only 2.5 barrels of steam for every one barrel of oil produced. The longer-term objective is further improvement to about two times. EnCana continues to look for ways to improve its economics. It is testing additives such as butane or propane to improve recovery rates and lower the volume of gas required to produce a barrel of oil. EnCana has also advanced the development of high-temperature, low-pressure pumps, which have delivered reliable performance during field production. EnCana has joined other producers in blending bitumen with other oil streams to expand sales opportunities with refiners. It's these kinds of innovative and incremental improvements that have placed EnCana at the leading edge of oilsands growth through SAGD. In 2004, EnCana's SAGD projects are expected to produce 38,000 barrels per day, more than a 40 percent increase from the average production of 27,000 barrels per day in 2003. EnCana's SAGD development strategy has been twofold: test the technology to prove its economic performance then build production capacity in manageable incremental steps that focus on cost control and the market's capacity to accommodate the added volumes. Future expansions are under consideration that could raise production to more than 100,000 barrels per day later this decade.

"After four decades of development and 50,000 gas wells by the industry, we're still learning about the huge, long-term potential of Canada's largest gas field and the source of one of EnCana's most profitable businesses – shallow gas."

JEFF WOJAHN

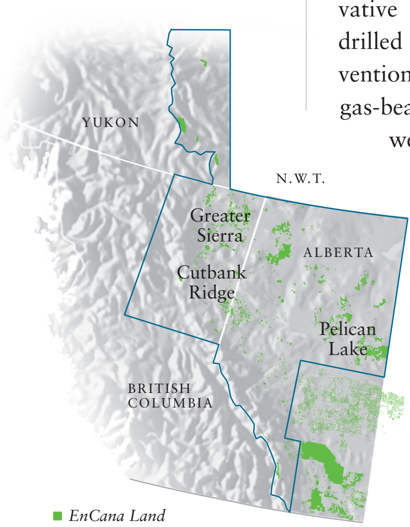


Canadian Foothills & Frontier

VISION MATTERS

"We've sharpened our geological focus on the discovery and capture of large, sustainable, productive hydrocarbon reservoirs where the vision and execution of our multi-disciplinary teams produce the kind of resource plays we've captured at Cutbank Ridge and Greater Sierra."

MIKE GRAHAM



A COMPETITIVE EDGE

Northeast British Columbia natural gas resource plays are in their infancy. Advanced drilling technologies have just started to unlock the massive gas volumes in Greater Sierra's Jean Marie geological formation, and in the Cadomin formation under Cutbank Ridge lands. With high working interests in over 4 million net undeveloped acres and operatorship of the processing and pipeline infrastructure, EnCana holds a clear advantage as it pursues reliable, profitable gas production growth. At Pelican Lake, in northeast Alberta, the region's largest waterflood project is expected to more than double oil production by 2006.

GREATER SIERRA

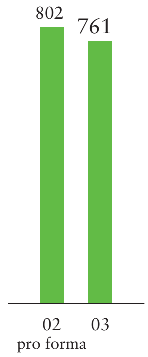
Once a domain where drilling occurred only after winter froze the muskeg, Greater Sierra has become a year-round oil and gas region. EnCana's high-growth B.C. resource play was built over the past four years by applying innovative techniques such as horizontal wells drilled with nitrogen foam rather than conventional mud which tends to invade the gas-bearing formation. These underbalanced wells unlock the large but once-marginal resource. To minimize surface disturbance and cut costs, up to four horizontal well bores are drilled from a single lease site. Recently, a new tool has been added – wooden mats linked together in summer to form short-distance roads and drilling islands that prevent trucks and rigs from sinking into the soft muskeg. It's an ideal solution, one that has kept rigs and equipment running year round and contributed to a 40 percent reduction in average well costs since 2000. While technological advances have improved Greater Sierra's prospects, so has the investment climate. The B.C. government's royalty programs for deep wells, horizontal wells, low productivity wells and summer drilling have encouraged activity. The province also partnered with industry by investing in road construction and maintenance to improve access to remote development areas. In 2003, EnCana acquired about 400 square miles of land, expanding its holdings to about 4,200 square miles and raising Greater Sierra's natural gas potential. Production increased by about 30 percent to average 143 million cubic feet per day, and exited the year at 215 million cubic feet per day. To date, EnCana has about 500 wells which, at a density of one per square mile, tap less than 15 percent of the company's Greater Sierra land base. With a five-year inventory of more than 1,000 drilling locations identified and the new Ekwan Pipeline expected to expand the region's takeaway capacity by mid 2004, Greater Sierra, though only in its infancy, continues to prove why it's a world-class gas discovery.

CUTBANK RIDGE

More than a year of intense geo-technical work had been poured into the Cadomin formation by the time the Cutbank Ridge exploration team submitted bids for EnCana's largest ever land acquisition – a $270 million purchase of about 350,000 net acres. In the 18 months prior, EnCana had already assembled 150,000 net acres in the region through purchases, land swaps and Crown land sales. When this

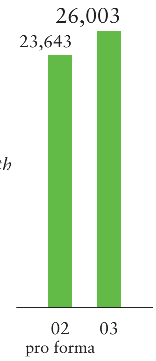
TOTAL GAS SALES
(MMcf/d)

Portfolio realignment is positioning for strong future growth.



TOTAL OIL & NGLs SALES
(bbls/d)

Waterflood technology is driving oil production growth at Pelican Lake.



land assembly was completed, EnCana had captured a major new resource play called Cutbank Ridge, which straddles the Rocky Mountain foothills along the B.C.-Alberta border. Like its predecessor B.C. resource play, the Jean Marie geological formation at Greater Sierra, the Cadomin formation had long been known to contain potentially significant quantities of natural gas. Yet, no one had figured out how to profitably extract it. It was not a conventional gas discovery where one or two wells flowed at strong rates. Rather it was tailor made for EnCana's resource play expertise. It takes vision to conceptualize such unconventional exploration plays, geological competency and technical know-how to evaluate and unlock the potential, stealth-like strategy to capture the land and financial strength to move with speed. Combining these qualities is the competitive advantage that EnCana employed to acquire Cutbank Ridge, the kind of high-quality asset that has the potential to deliver long-life production growth for many years ahead. In the last half of 2003, EnCana drilled 19 wells in Cutbank Ridge, where production exited the year at about 14 million cubic feet per day and is expected to exit 2004 at about 40 million cubic feet per day. It is anticipated that Cutbank Ridge could produce several hundred million cubic feet per day of gas by 2007.

PELICAN LAKE

EnCana is in the midst of significantly ramping up heavy oil production at Pelican Lake following the successful completion of eight waterflood pilot projects. With about 2.3 billion barrels of original oil in place on EnCana's Pelican Lake lands, and an estimated 1 billion barrels of resource that can be economically waterflooded, the key to success lies in improving recovery factors. Production in 2003 averaged about 16,000 barrels per day, but that's just the start. On primary production, Pelican Lake wells typically declined to about 25 barrels per day, yet the application of horizontal drilling and waterflood techniques has raised those well rates back to their initial production rates of over 200 barrels per day. As well, under waterflood, we believe we can double recovery levels. In 2003, EnCana drilled about 130 injectors and producing wells and production in 2004 is expected to average about 21,000 barrels per day. With that growth comes economies of scale as operating costs are forecast to average below $3.50 per barrel in 2004. And there's further growth potential beyond.

FRONTIERS

EnCana's East Coast initiatives continued to show substantial promise as the company began work on a new development plan for its Deep Panuke natural gas discovery. The changing operating, industry and market environment in this emerging basin caused EnCana to re-evaluate its original development plan and look for the most economic way to develop the discovery. Additional exploration in 2003 resulted in two successful natural gas wells at Margaree and MarCoh, near Deep Panuke. EnCana continues to explore in the deep waters off Canada's East Coast and in the Mackenzie Delta of Canada's Northwest Territories.

MIKE GRAHAM

President

Canadian Foothills

& Frontier Region

U.S.A.

FULL-CYCLE INNOVATION MATTERS

"People here challenge each other to continually improve, do their job better, drill a well faster and cheaper, frac formations more effectively, reduce our environmental impact and improve our stakeholder relations. Like our production growth, our opportunities for improvement are sustainable, built on full-cycle innovation."

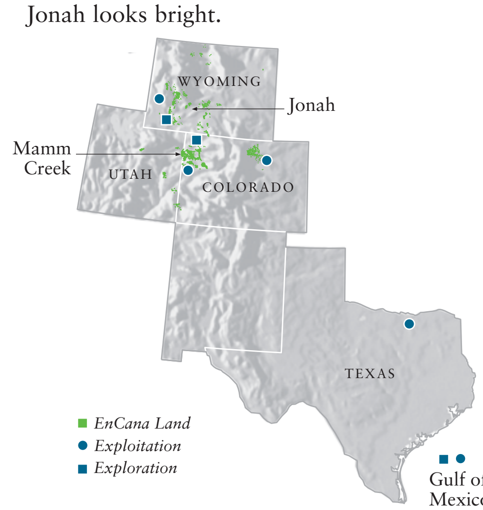
ROGER BIEMANS

APPLYING CONTINUOUS LEARNING

In the Rocky Mountain states, where the elevation is more than one mile above sea level, there sit a series of sedimentary basins containing thick layers of ancient sands packed tightly with natural gas. In the past four years, EnCana has systematically and successfully assembled an attractive portfolio of deep, tight, multi-zone natural gas resource plays. By leveraging its unconventional resource development expertise, EnCana has grown production and reserves with infill drilling, made opportune acquisitions and expanded through exploration. Our U.S.A. resource play pursuits have created the company's fastest growing region, where 2003 reserve additions exceeded 330 percent of annual production, heralding continued strong growth in the years ahead. Our U.S.A. gas production has grown rapidly each year since 2000. It now exceeds 650 million cubic feet per day with three-quarters of the growth coming through the drill bit. The company's two anchor assets – the Jonah gas field in Wyoming and the Mamm Creek gas field in Colorado – continue to outpace original expectations, with development drilling in 2003 further expanding the potential of these fields. EnCana has also added a series of emerging opportunities in the Piceance Basin in Colorado and in north Texas.

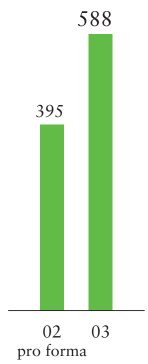
JONAH

Spanning just 30 square miles of southwest Wyoming, the Jonah natural gas field contains an estimated 10 trillion cubic feet of original gas in place, an average of 300 billion cubic feet per square mile. EnCana owns about 75 percent of it. Jonah's treasures lie deep underground, in a zone between 8,000 and 11,500 feet. This gas-charged zone is thicker than two Empire State buildings stacked on top of each other. Since Jonah's discovery in 1986, wells have been drilled on 40 acre spacing. Through pilot projects, EnCana has determined there's plenty of untapped natural gas between the wellbores. Initial tests of wells from increased density pilot projects have delivered strong results, with several geological horizons at original pressures and production rates similar to wider-spaced wells. Knowing there is far more gas to recover, EnCana is seeking regulatory approval to increase drilling density. This approval process includes completion of an environmental impact assessment by the U.S. Bureau of Land Management, which is expected later in 2004. Upon completion of the environmental impact assessment, EnCana plans to increase drilling and significantly grow production. This infill potential adds a five-year inventory of up to 1,200 wells. Add to that the application of recompletion techniques of bypassed zones in wells drilled before 2000 and the future of Jonah looks bright.



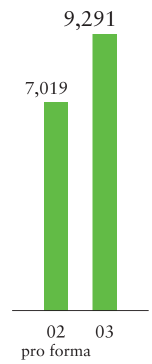
TOTAL GAS SALES
(MMcf/d)

The U.S.A. continues to be EnCana's highest growth region.



TOTAL NGLs SALES
(bbls/d)

Liquids rich gas production drives growth.



ROGER BIEMANS

President

U.S.A. Region

MAMM CREEK

Oil and Gas Investor Magazine recently named Mamm Creek as the Best Field Rejuvenation in 2003, recognizing the tremendous growth achieved over the past couple of years from this high-quality Colorado property. This is a success story of continuous innovation. Mamm Creek's gas-bearing zone is typically 2,500 feet thick. These tight sandstone reservoirs contain large volumes of natural gas that are trapped by the dense structure of the rock. Freeing the gas requires high-pressure rock fracturing. In 2000, the accepted technique called for splitting the gas-bearing zone into several zones through fracture stimulation, yielding typical initial gas production rates of about 500,000 cubic feet per day. Through experiment and pilot testing, EnCana has made great strides with more frequent fracs across narrower intervals. Instead of two big frac jobs, EnCana now executes up to eight fracs across the same 2,500-foot zone. When improved fracturing techniques are applied, the gains are monumental, tripling production to more than 1.4 million cubic feet per day from the same formations.

On the drilling side, a steady focus on increased efficiencies has cut the average well time more than 35 percent – to 14 days from 22, resulting in savings of $100,000 per well. Mamm Creek's next step towards increased production and gas recovery is to infill drill in areas with high gas reserves, reducing spacing from one well every 20 acres to one every 10 acres. Initial infill drilling results have shown that the in-between wells produce at rates similar to the initial wells. These increased efficiencies generate exponential benefits through the extension of the play in numerous directions away from the core field. Covering about 8,000 acres in 2000, Mamm Creek has grown each year to now cover over 100,000 net undeveloped acres. Producing about 25 million cubic feet per day in early 2000, the field averaged 125 million in 2003 and exited the year producing more than 190 million cubic feet per day. Not bad for a rejuvenation project.

EMERGING RESOURCE PLAYS

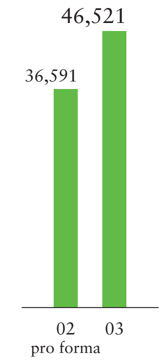
EnCana U.S.A. continues to build on its success at Jonah and Mamm Creek by targeting new multi-zone tight sands, coalbed methane, and gas shale opportunities. With existing projects like those already captured in the Eureka and East Hunter Mesa areas of the Piceance Basin, and the newly expanded Fort Worth Basin in north Texas, EnCana has developed an extremely strong inventory of resource plays that are expected to help EnCana deliver strong gas growth for years to come.

GULF OF MEXICO

Appraisal drilling of the 2002 Tahiti discovery, owned 25 percent by EnCana, has continued to prove up this world-class asset – one of the largest discoveries in the deep water Gulf of Mexico to date. Development planning is well underway with final concept selection and project approval expected in 2005. Beyond Tahiti, EnCana expanded its exploration success in the Gulf of Mexico with 2003 discoveries at Tonga and Sturgis, each 25 percent EnCana, and St. Malo, 6.25 percent EnCana. With an inventory of several prospects waiting drilling, EnCana has established an attractive, deep water portfolio with the potential to provide meaningful light oil growth opportunities over the medium term.

TOTAL OIL SALES
(bbls/d)

The opening of OCP doubled EnCana's production in late 2003.



Ecuador

A NEW PIPELINE MATTERS

DON SWYSTUN

President

Ecuador Region

"The country and the people of Ecuador crossed a historic economic threshold in 2003 with the completion of the 500-kilometre OCP Pipeline – a major infrastructure project that opens new opportunities in this South American country."

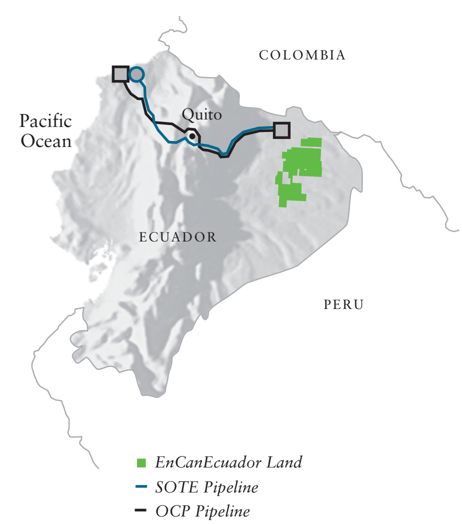
ENCANECUADOR DOUBLES PRODUCTION

EnCanEcuador's 2003 production averaged 51,000 barrels per day. Current production of about 73,000 barrels per day is double its 2002 average. EnCanEcuador's 100 percent owned Tarapoa block produces more than 40,000 barrels per day. Prior to the OCP Pipeline coming on stream, EnCanEcuador expanded Tarapoa's production and processing capability, drilling 32 wells in 2003, and reduced drilling costs by more than 20 percent. In the undeveloped eastern portion of the 90,000-acre Tarapoa block, EnCanEcuador is evaluating the exploration potential after completing a three-dimensional seismic program in 2003. EnCanEcuador's second largest producing asset is a 40 percent non-operated interest in Block 15, where net EnCanEcuador production is about 30,000 barrels per day. Productive capacity also increased in 2003 following the completion of a new facility at Eden Yuturi and a 24-inch pipeline. Bordering on Block 15, EnCanEcuador acquired a majority interest in two early-life production properties – Blocks 14 (75 percent) and 17 (70 percent). Investments on these blocks included nine wells, plus facility upgrades and expansion. EnCanEcuador is forecasting a 50 percent increase in average daily sales in 2004.

EnCanEcuador's commitment to employee safety, the environment and surrounding communities is evidenced by the recently-granted ISO 14001 certification for the environmental management system at the company's Lago Agrio crude oil storage and transfer facility. EnCanEcuador and Fundación ÑanPaz continue their commitment to sustainable development by enhancing the health, culture, education and agricultural diversification of the rainforest communities where EnCanEcuador operates.

OCP – VISION BECOMES REALITY

When EnCana entered Ecuador five years ago the opportunity was clear. Oil development potential was substantial, but it would never be fully realized without the addition of fundamental infrastructure – a new pipeline to connect the inland Oriente Basin with export markets via a Pacific Coast port. The existing SOTE pipeline was operating at capacity, placing a cap on any growth in daily production. Comprehensive negotiations between the OCP consortium and the government were followed by the largest development project in the country's history. This 500-kilometre underground pipeline, which traverses South America's Andes mountains, has a capacity of 450,000 barrels per day. The final weld was completed August 18, 2003 and one month later the first tanker loads of a new blend of crude named NAPO sailed onto the world market.



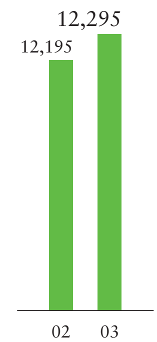
U.K.

NEW EXPLORATION THINKING MATTERS

TOTAL SALES

(BOE/d)

EnCana is building its North Sea operating expertise.

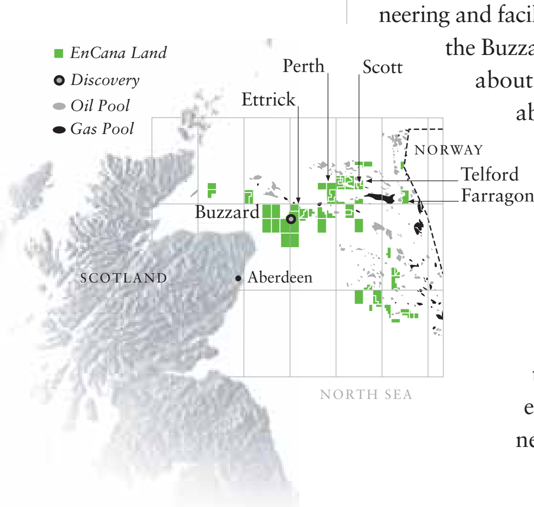


ALAN BOOTH

Managing Director

U.K. Region

"From the very start, we were not prepared to accept the conventional wisdom that stratigraphic traps rarely, if ever, work in the North Sea. Now we're developing the largest U.K. oil discovery in the past decade."



BUZZARD FIELD ON TRACK FOR 2006

From discovery to regulatory approval in 30 months, the Buzzard oil field, containing about 1 billion barrels of original oil in place, is well on its way to delivering first oil in late 2006. On November 27, 2003, the United Kingdom Department of Trade and Industry granted regulatory approval for development of the most significant U.K. oil find in the past decade. Buzzard is a product of innovative thinking, where EnCana applied creative geological techniques to a basin once considered by many to be too mature for world class discoveries. Before Buzzard, the vast majority of the major oil finds in the U.K. central North Sea were structural accumulations. EnCana believed that if large stratigraphic, oil-bearing reservoirs existed in other basins, there was no reason why they wouldn't be here. In May 2001, the discovery of Buzzard proved EnCana's geologists right and sparked an exploration renaissance aimed at stratigraphic traps in the North Sea. On the Buzzard project, hundreds of people are now working on the topsides design, steel jacket fabrication, pipeline engineering and facilities installation. By mid 2007, the Buzzard field is expected to produce about 180,000 barrels per day, with about 75,000 barrels per day net to EnCana. Based on U.K. government industry forecasts, it's expected that at its peak rate Buzzard could be responsible for 10 percent or more of the United Kingdom's total oil production. Beyond that, EnCana explorers continue to apply new thinking on its 48 North Sea licences, covering 740,000 net undeveloped acres, in their search for additional reserves to extend the life of EnCana's emerging U.K. region.

SCOTT AND TELFORD FIELDS

In a two-step process over the past year, EnCana significantly expanded its U.K. central North Sea production and operations by more than doubling its ownership of the Scott and Telford oil fields. In October 2003, EnCana acquired an additional 14 percent interest in the Scott and Telford fields and took over operatorship of the fields. With sales averaging 12,300 barrels of oil equivalent per day of production and exiting 2003 at about 21,000 barrels of oil equivalent per day, EnCana is quickly accumulating operating experience as it builds a core region in the North Sea. In early 2004, EnCana concluded another acquisition adding a 13.5 percent interest in Scott and a 20.2 percent interest in Telford, taking EnCana's interest to 41 percent of Scott and 54.3 percent of Telford. Current production is more than 24,000 barrels of oil equivalent per day. The company is focused on using its subsurface expertise to improve reservoir performance and its low-cost operations experience to drive down costs from mid-life production assets such as Scott-Telford. It will then apply that knowledge and experience to every phase of development of Buzzard. The Perth and Ettrick fields, located nearby, may become future satellite developments. Beyond that, EnCana is exploring for additional discoveries in the vicinity that could increase production, lower per-unit production costs and extend the life of the Scott-Telford and Buzzard facilities.

Exploration

MATERIAL DISCOVERIES MATTER

JOHN BRANNAN

Managing Director

International New

Ventures Exploration

"We take a highly-selective approach to drilling international wells in under-explored basins where we can apply our expertise in stratigraphic plays."

IDENTIFYING HIGH-IMPACT OPPORTUNITIES

Hunting for new resource plays and applying a distinct and well-developed understanding of conventional stratigraphic plays to new basins set EnCana on a unique exploration path in North America and overseas. EnCana's international exploration programs are designed to provide large, conventional discovery upside, such as at Buzzard and Tahiti. These large frontier and international discoveries build asset value and create options for future, long-term growth. About 10 percent of EnCana's capital investment is directed to exploration, split about evenly between pursuing North American resource plays and frontier and international discoveries. In 2003, EnCana drilled 604 net exploration wells onshore North America, and participated in 28 high-impact frontier and international exploration wells on four continents.

NORTH AMERICAN EXPLORATION

There's a new face to oil and gas exploration at EnCana. In 2003, more than 10 percent of the company's 5,632 net wells were directed to identifying new resource plays, making EnCana a leading North American explorer. The days of pinning one's hopes on single-well exploration success are fading. EnCana's explorers are testing resource play concepts that typically prove out only with intense diligence and geological work followed by the capture of large land tracts containing huge resources. Almost all of EnCana's exploration wells drilled in 2003 were on lands the company knows very well. No big gushers here, but hundreds of single wells that are methodically assembled to piece together a geological puzzle yielding a major resource play capable of sustainable, long-life production. Cutbank Ridge, the company's most promising new resource play, is no different. Much of the exploration on this prospect was done not with EnCana's rigs, but with someone else's drill bit. EnCana drilled 25 wells, and examined the geological records of more than 300 wellbores, before defining the size and potential of the Cadomin formation. This collective, incremental approach is the new face of resource play exploration.

FRONTIER AND INTERNATIONAL PURSUITS

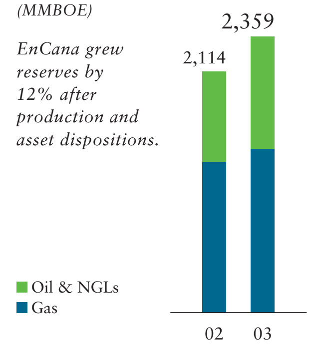
Elsewhere in EnCana's exploration world, in the North American frontiers – the Arctic, East Coast and deep water Gulf of Mexico – and overseas, discoveries are being made. As a follow-up to the 2002 Tahiti discovery, the company participated in Gulf of Mexico discoveries at Tonga, Sturgis and St. Malo in 2003. In the U.K. central North Sea, the company participated in the Farragon discovery. These single-well big hits are long-term investments that add value, but they take time. Even the most promising of these big-hit discoveries – the North Sea's Buzzard field – takes five to six years to bring on stream. Discovered in 2001 and developed in a comparatively short time frame, Buzzard's first production is set for late 2006. In 2004, EnCana is selectively drilling for high-impact discoveries in the Mackenzie Delta, the Gulf of Mexico, offshore Nova Scotia, the U.K. central North Sea, offshore Brazil, Chad and the Middle East. Any of these frontier and international wells could result in new core production regions or options for future growth.

Reserves

GROWING UNDERLYING VALUE MATTERS

RESERVES
(MMBOE)

EnCana grew reserves by 12% after production and asset dispositions.



BRIAN FERGUSON

Executive Vice-President

Corporate Development

"For an oil and gas company, external assessment of reserves is just as important as external assessment of financial statements. EnCana employs the highest level of rigour in reserves assessment, having 100 percent of our reserves externally evaluated every year."

RIGOROUS ASSESSMENT OF RESERVES

Reserves are the foundation of an oil and gas company. EnCana believes its practice of having a 100 percent independent, external evaluation provides the highest level of scrutiny that can be applied to this most important asset. EnCana has a reserves committee of independent board members which reviews the qualifications and appointment of the independent qualified reserve evaluators. The committee also reviews the procedure for providing information to the evaluators. All booked reserves are based upon the annual reserves reports prepared from the fundamental geological and engineering data. EnCana engages some of the industry's most respected engineering firms, listed on page 129 to evaluate its reserves. The company has a practice of not booking reserves until commercial development is proceeding, hence larger discoveries at Tahiti and Deep Panuke have not been included.

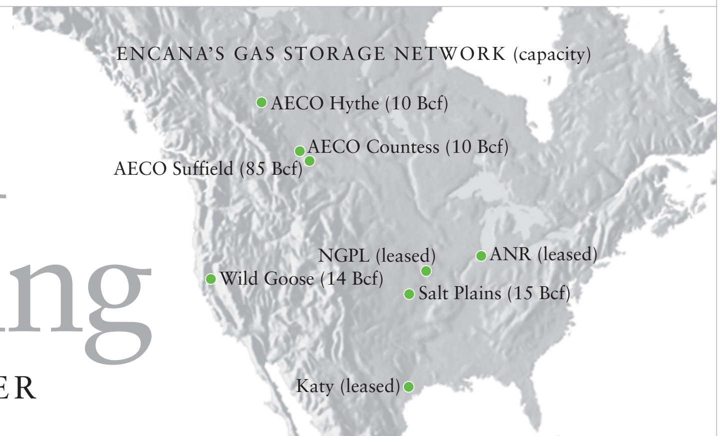
In 2003, EnCana added 482 million barrels of oil equivalent of proved reserves. These additions increased the company's total proved reserves to 2.36 billion barrels of oil equivalent, representing growth after production of 12 percent. The additions replaced 203 percent of EnCana's 2003 production, at a finding, development and acquisition cost of $8.75 per barrel of oil equivalent. Essentially all additions were the result of the company's successful 5,600 net-well drilling program and positive revisions, with the majority coming from established resource plays. The company's proved reserve life index remained at 10 years.

Reserves growth was primarily concentrated in onshore North America, which contains about 90 percent of EnCana's reserves and production. North America natural gas accounted for approximately 60 percent of the company's reserve additions. Major areas of gas reserves growth were in the Jonah and Mamm Creek gas fields in the U.S. Rockies, the Greater Sierra and Cutbank Ridge properties in northeast British Columbia and in coalbed methane lands in southern Alberta. Oil reserves growth was primarily from Foster Creek and Pelican Lake in northeast Alberta.

Proved undeveloped reserves represent 39 percent of total proved reserves, a level that is consistent with EnCana's resource play focus and production growth outlook. The undeveloped gas reserves are concentrated primarily in the U.S. Rockies and northeast British Columbia resource plays and can be developed with infill or step-out drilling. The undeveloped oil reserves are primarily at Foster Creek in Alberta and Buzzard in the U.K. central North Sea. The company plans to develop about 80 percent of the proved undeveloped reserves over the next three years.

Midstream & Marketing

MARKET FUNDAMENTALS MATTER



OPTIMIZING RETURNS

"We are focused on capturing the best possible netbacks for EnCana's production and returns on our midstream assets."

BILL OLIVER

EnCana's Marketing group is focused on monitoring and analyzing North American and world oil and natural gas supply and demand fundamentals that drive price forecasts and sales strategies. EnCana continually strives to move all of its production volumes to markets that provide the best possible netback. Midstream initiatives – gas storage, transportation, natural gas liquids extraction and power generation – create value through third-party contracting, product sales and supporting EnCana's upstream operations.

GAS STORAGE

The goal of EnCana's gas storage business is to create value by being the leading owner and operator of independent, non-utility natural gas storage assets in North America. As a predominantly upstream company, EnCana adds value in its storage unit by applying upstream technologies, such as horizontal drilling techniques, to improve efficiencies in gas storage development and operations. In addition, EnCana is a leader in applying commercial optimization techniques in an industry dominated by cost-of-service utility operations. Revenue is generated by leasing capacity to third parties and also by purchasing gas for storage during times of lower prices, for withdrawal and sale during periods of predicted higher prices. Storage also provides EnCana's upstream operations the unique opportunity to inject produced gas and avoid well shut-ins during operational upsets such as pipeline outages or severe price declines.

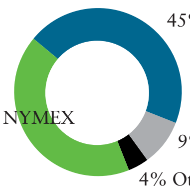
The market for North American gas storage softened considerably in 2003 due to a low summer/winter price spread in the contracting period early in the year, moderate price volatility and the retreat of energy merchants from the storage market. While the value of storage capacity will continue to fluctuate, EnCana believes North American gas trends suggest continued strong growth in market demand for natural gas storage capacity. A recent U.S. National Petroleum Council (NPC) study projects that gas supply will struggle to keep pace with demand as total gas consumption becomes more seasonal and weather sensitive. The NPC projects that 700 billion cubic feet of new storage capacity will be needed by 2025 to meet demands of a normal weather year. It also cautioned that existing storage capacity could be severely challenged in the near term by a significantly colder than normal winter.

EnCana owns and operates approximately 134 billion cubic feet of working gas capacity in three facilities: the AECO Hub™ – 105 billion cubic feet in Alberta, Wild Goose – 14 billion cubic feet in California, and Salt Plains – 15 billion cubic feet in Oklahoma. 2003 saw significant expansion of the EnCana gas storage network. The company built 10 billion cubic feet of new gas storage capacity at Countess, one of three Alberta facilities that make up the AECO Hub™. Full development is expected to take the Countess capacity to 40 billion cubic feet by 2005, with an expected withdrawal capability of 1.2 billion cubic feet per day. In northern California, completion of a 10 billion cubic feet expansion at the Wild Goose facility is expected in April 2004, doubling the facility's withdrawal capability to 480 million cubic feet per day. With

GAS PRICE EXPOSURE

2004 Forecast

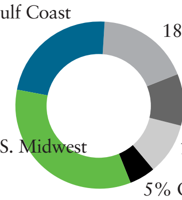
The company locks in returns and remains open to price upside.



LIQUIDS SALES MIX

2004 Forecast

EnCana has geographically diversified sales.



its recently expanded storage network, plus other projects underway or in planning, EnCana expects to fortify its position as a leader in independent gas storage.

MIDSTREAM

In early 2003, EnCana sold its interests in the Cold Lake Pipeline System and Express Pipeline System for about $1 billion, including the assumption of related long-term debt by the purchaser. These oil pipeline sales were part of EnCana's strategic realignment to focus on its large portfolio of higher-return growth assets.

MARKETING

EnCana's marketing business focuses on achieving the best price for its products. Value is added through the development and implementation of transportation and asset optimization strategies to maximize the company's netbacks.

In 2004, natural gas sales are expected to account for approximately 70 percent of EnCana's revenue. During 2003, EnCana's gas marketing group revised its sales strategy to focus on large industrial, local distribution companies and wholesale customers. To reduce the risk of default, the majority of customers have a credit rating exceeding BBB+. In addition, to protect against weak regional prices in the U.S. Rockies and Western Canada, EnCana gas marketing contracted for additional transportation capacity and entered into both physical and financial basis contracts. Details of these transactions are outlined in Note 17 to the Consolidated Financial Statements.

In crude oil marketing, EnCana is the first Canadian producer to publicly post its crude oil prices. By posting prices on its website www.encana.com, EnCana expects to provide greater price visibility for Canadian crudes. Historically, Canadian crudes have traded at sizable discounts to refiners' U.S. domestic and international alternatives and the company's postings intend to achieve closer pricing parity with these alternatives.

A new blend of Ecuadorian crude oil, NAPO crude, was created and introduced to the world markets with the start-up of the OCP Pipeline in September 2003. EnCana's oil marketing group successfully brought this new blend to market through proactive market development in the U.S., South American and Asian markets. In addition, EnCana supported the re-activation of the Petroterminal de Panama, which traverses Panama from the Pacific to the Atlantic. This re-activation gives EnCana a competitive cost advantage in accessing the U.S. Gulf Coast markets.

EnCana also manages volatility in crude oil prices through the use of various crude oil risk management contracts. The details of these transactions can be found in Note 17 to the Consolidated Financial Statements.

BILL OLIVER

President

Midstream &

Marketing Division

ENCANA CORPORATION

Energy for People

Leadership Beyond the 100

Innovation

Building Capacity

Bottom Line

%

Externally Evaluated Reserves

15/16

Community Investment Program

Directors Independent of Management

EnCanans

PEOPLE AND INFORMATION MATTER

"Behind the complex business of producing energy for people is a high-performance team focused on facilitating the success of the business by making it easier for all EnCanans to do their job."

DRUDE RIMELL

FOSTERING A HIGH PERFORMANCE CULTURE

EnCana's commitment to its shareholders is evident in the underlying strategy for people and their work environment. It's simple: hire the best people, provide them with the best tools and information and allow them to do their best work. The result is a highly productive and motivated workforce that contributes to shareholder growth and returns. EnCana creates and fosters a high performance culture through competitive human resources programs and results-based compensation. The company provides its highly informed and agile workforce with cost-effective technology that supports business productivity and speed.

Successfully integrating two of the country's largest oil and gas companies was a logistically complicated and immense task. While many aspects of a merger of this magnitude are public, much of the business integration happens behind the scenes. The focus was on delivering fast and effective products and services to teams and individuals across the company. The goal was minimum business disruption or down time and maximum productivity. The result: a productive environment for EnCana to reach its sales and reserve growth targets, without missing a beat.

One of EnCana's greatest assets is its people and the vast amount of experience and technical skills they bring to the business. The organization of people into business units creates a powerful opportunity to focus on specific operational areas. Programs such as technical forums bring people together to share knowledge and establish best practices across business units and throughout the company.

EnCana builds a high performance work culture, where leadership, business and technical abilities foster individual accountability for results. Employees' interests are aligned with shareholders and performance is rewarded. Every EnCana employee signs an annual contract setting high performance objectives. The degree to which these are achieved plays a crucial role in determining annual compensation. Beyond individual performance, and as part of the long-term incentive plan, EnCana introduced performance share units to its executives and senior management in 2003 to partially replace stock option grants. Under this system, payment depends on how the company's shares perform compared to its peers. Extension of performance-based share units to all employees is scheduled for 2004.

REMARKABLE ENCANANS

Every day across EnCana, staff achieve remarkable results by applying innovation, creativity and stepping beyond the norm. 2003 saw numerous stories of excellence. Here are just a few.

Instant commerce

EnCana's U.S. field operators, engineers and accountants used to manually keep track of bills. Valuable time and money was spent sending invoices through the mail system, waiting for them to be processed internally, and then waiting for cheques to move back through the system. This entire process typically cost $20-$40 per transaction, and took from 30 to 60 days to complete. Then came Digital Oilfield's OpenInvoice™ system. Now the invoice and a signed proof of service flow electronically from the field to the supplier's billing system, and then to EnCana's accounts payable group. Approval and payment are now possible in a matter of hours, in an entirely paperless

DRUDE RIMELL

Executive Vice-President

Corporate Services

transaction, for a mere fraction of the cost. During 2003, the number of invoices processed by this means was up ten-fold, to more than 34,000 across North America. The dollar volume processed increased more than six times to exceed $220 million per quarter and savings are piling up every day.

Fast and safe gas storage

From concept to completion in just over a year, the Countess storage development team constructed the first phase of a new gas storage facility that will ultimately expand EnCana's AECO Hub™ by about 40 billion cubic feet to about 134 billion cubic feet of capacity. The facility's speedy completion, which included drilling of 25 horizontal wells and construction of a 27,000-horsepower surface facility, enabled EnCana to inject 10 billion cubic feet of gas before winter 2003-2004. Notably, the fast-track development occurred without a single lost-time accident.

Coalbed consultation

They adapted field technology, negotiated with landowners, drilled hundreds of wells, added proved reserves, cut costs and launched Canada's first major commercial development of coalbed methane. By leveraging EnCana's extensive shallow gas expertise, the Calgary business unit developed a new well fracturing procedure. It unlocked a known resource play to add significant proved reserves while cutting well costs 30 percent. Along the way, field operators, engineers and landmen collectively changed the way they deal with the public. A new community consultation process made it possible for EnCana to drill as many wells by mid January 2004 as it did in the first five months of 2003, leaving the rest of the year to drill the second half of the program, an outstanding accomplishment by any industry measure.

Passion for wildlife

Managing the fine balance between nature and oil and gas development is a demanding responsibility and one that EnCanans do not take lightly. Over the past decade, an EnCana employee has translated EnCana's commitment to benchmark practices in environmental stewardship from theory into a reality. In 2003, the internationally recognized National Wildlife Area at the Canadian Forces Base at Suffield, Alberta was legislated a federally protected area and EnCana was formally recognized for its significant contribution during that process. The 450 square kilometres of pristine ecosystem is now, and will always be, protected thanks to the passion, persistence and perseverance of an EnCana employee.

Lifetime of community contribution

EnCana's Vice-President of Aboriginal Relations is the only industry representative to receive the Lifetime Achievement Award for pioneering innovative capacity building programs between EnCana and Treaty 6 First Nation communities. EnCana's practices, which encourage using local aboriginal businesses and identifying employment and training opportunities, have resulted in numerous successful ventures. EnCana also played a major role in a landmark deal for the first aboriginal owned and operated drilling rig in northeast British Columbia.

Corporate Responsibility

ETHICAL BEHAVIOUR MATTERS

"EnCana's reputation is critical to the creation of long-term value for our shareholders. Our success on the bottom line is reinforced by our behaviour beyond the bottom line."

GERRY PROTTI

SHARED PRINCIPLES

EnCana is a two-year-old company built upon more than a quarter century of vibrant history, rich traditions and the sustainable performance inherited from its predecessor companies. Upon this extraordinary foundation, EnCana is developing its own traditions, practices and guideposts. In 2003, EnCana set out its founding principles in a unique Corporate Constitution. Here are the highlights:

EnCana's journey is guided by a Corporate Constitution that sets out the foundation of our values and what we each can do to thrive and grow; an inner compass that keeps us moving in the right direction on our journey to build a great company. The Corporate Constitution sets out what we expect of one another; it inspires us; it empowers us; and it makes us accountable to one another.

Our vision is to create a truly great company – one where quality work is the norm; where we stretch and strive to be the best we can be; and where great things are accomplished. Principles grace every decision and punctuate every interaction along our journey. Shareholders and other stakeholders support our endeavours because we have earned their trust and respect.

OUR MISSION

Energy for People.

OUR VISION

EnCana will be the world's High Performance Benchmark independent oil and gas company.

OUR CONSTITUTIONAL MERITOCRACY

EnCana is a company where shared principles guide our behaviour and merit determines our reward.

OUR JOURNEY

Achieving great things together.

SHARED PRINCIPLES

Strong Character We understand that sustained shareholder value can only be delivered by people of strong character. We lift one another up to greater success, we are determined, dynamic and disciplined, and we can be counted on.

Ethical Behaviour We function on the basis of trust, integrity, and respect. We are committed to benchmark practices in safety and environmental stewardship, ethical business conduct, and community responsibility. Our success is measured through both our behaviour and our bottom line.

High Performance We focus where we passionately believe we can be the best. We are accountable for delivering high-quality work that's continually enriched by open, dynamic lookbacks and learning.

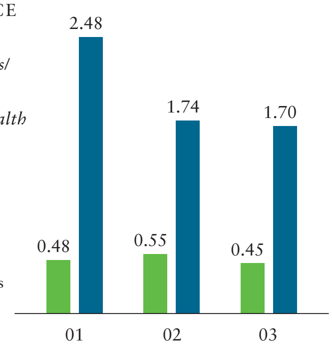
Great Expectations We have great expectations of one another. Living up to them will enable us to experience the thrill and fulfillment of being part of a successful team, and the pride of building a great company.

EnCana's entire Corporate Constitution is available on the company's website at www.encana.com.

IMPROVED SAFETY PERFORMANCE 2001 – 2003

Frequency (Incidents/ 200,000 hours)

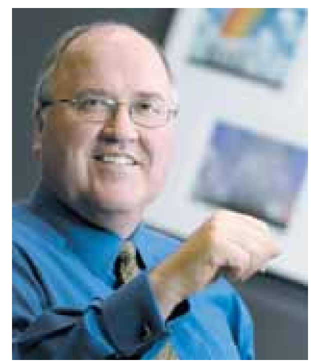
Protecting the health and safety of EnCanans.



GERRY PROTTI

Executive Vice-President

Corporate Relations



ENCANA'S COMMITMENT TO CORPORATE RESPONSIBILITY

In 2003, EnCana developed a Corporate Responsibility Policy that translates its constitutional values and shared principles into clear policy commitments that apply throughout the company. The policy is supported by practices, guidelines and other tools to facilitate implementation and accountability. The policy commits EnCana to conducting business ethically, legally and in a manner that is fiscally, environmentally and socially responsible, while delivering sustainable value and strong financial performance. EnCana's Corporate Responsibility Policy applies to everything the company does, everywhere in the world it does business.

ELEMENTS OF ENCANA'S CORPORATE RESPONSIBILITY POLICY

EnCana's Corporate Responsibility Policy, posted on www.encana.com, is built on the following eight areas of commitment that reflect existing and emerging benchmarks of corporate responsibility:

- Leadership commitment
- Sustainable value creation
- Governance and business practices
- Human rights
- Labour practices
- Environment, health and safety
- Stakeholder engagement
- Socio-economic and community development

INTEGRATING THE CORPORATE RESPONSIBILITY POLICY

The ongoing process of integrating corporate responsibility strengthens EnCana and its pursuit of excellence in everything it does. EnCana is committed to being a leader in corporate responsibility, and continues to make changes to reflect leading practices. Since the merger, EnCana has made important strides in fulfilling its commitments.

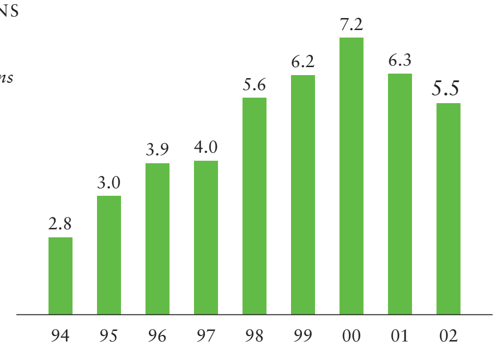
EnCana already has many practices and elements in place, such as its Environment, Health and Safety Best Practices, a set of operating procedures and guidelines. The company is working to ensure that the appropriate tools are in place to effectively guide, measure, monitor, and internally and externally communicate EnCana's corporate responsibility activities and practices. Moving forward, efforts will focus on internal awareness-building, training and education regarding EnCana's corporate responsibilities, and the continued development of supporting practices to guide behaviour. Work will also continue on developing a suite of performance indicators to monitor progress. An initial set of indicators has already been established in some of the areas of corporate responsibility, as described in the following pages.

Leadership Commitment

The Corporate Responsibility Policy makes EnCana's leaders and employees accountable for integrating corporate responsibility considerations into decisions early and consistently. EnCana's Executive Team was actively involved in developing the policy and is now helping to guide its implementation. The policy has been approved by EnCana's Board of Directors, to whom the policy also applies. In fact, the mandate of the environment, health and safety committee of the Board has been expanded to include corporate responsibility, ensuring that these matters have the highest level of attention at EnCana.

ENCANA GREENHOUSE GAS EMISSIONS
MT CO_2E

Absolute emissions are declining.



Sustainable Value Creation
EnCana recognizes the importance of corporate responsibility to sustained value creation. The Corporate Responsibility Policy commits EnCana to consider both short-term and long-term sustainable value creation in decision-making, and emphasizes that value creation depends on the company's high-quality assets, strong financial management and sound corporate governance.

Governance and Business Practices
EnCana is committed to maintaining the highest standards of integrity, ethical behaviour, and corporate governance. The Corporate Responsibility Policy publicly commits the company to compliance with all applicable laws and regulations, generally accepted accounting principles and alignment with leading corporate governance practices. The policy also commits EnCana to assess and manage risks effectively to protect all assets of the company. A clear example of this is EnCana's commitment to the independent evaluation of 100 percent of the company's oil and natural gas reserves each year, as outlined on page 29 of this report. Recognizing that EnCana's business activities also involve a wide network of partners, contractors and suppliers, EnCana is committed to work with this network towards achieving a level of performance consistent with the company's high standards of corporate responsibility.

Human Rights
EnCana recognizes human rights as a key aspect of corporate responsibility. While governments have the primary responsibility to promote and protect human rights, EnCana shares this goal and will support and respect human rights within the company's sphere of influence. EnCana will not engage or be complicit in any activity that solicits or encourages human rights abuse.

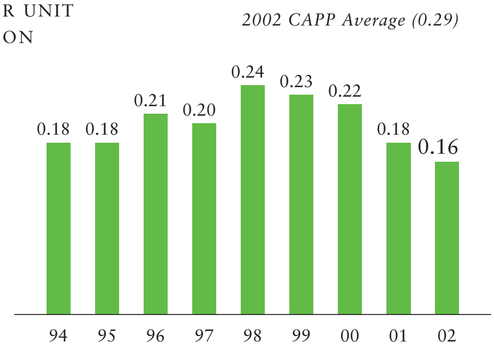
Labour Practices
A company is responsible for the well-being of its workforce. EnCana will not engage in or tolerate unlawful workplace conduct, nor engage in forced or exploitative labour practices. EnCana is committed to treating its workforce with dignity, fairness and respect in all locations. As part of EnCana's internal checks and balances, labour practices include whistle-blower protection to address workplace issues as they arise. To make a positive difference in the communities where it operates, EnCana strives to provide local employment and economic opportunities.

Environment, Health and Safety
The Corporate Responsibility Policy expands the company's previous policy commitments in environment, health and safety. In addition to a commitment to protecting the health and safety of all individuals affected by company activities, and to safeguarding the environment, EnCana will strive to make efficient use of resources, minimize its environmental footprint and conserve habitat diversity. The company will also strive to reduce emissions intensity and increase energy efficiency. These commitments are supported by the company's existing Environment, Health and Safety Best Practices – a set of operating procedures and guidelines implemented in 2003.

ENCANA GREENHOUSE GAS EMISSIONS PER UNIT OF PRODUCTION

PCI (CO_2E/m^3OE)

Emissions are declining on a per unit basis.



Environment – reducing water needed for drilling

In drilling operations around Suffield in southeastern Alberta, EnCana has reduced the volume of water used for a typical oil well by 60 percent. How did it happen? Specialized pieces of equipment called centrifuges were fit to the drilling rigs to assist in the recovery of reusable water. Centrifuges spin the used drilling fluids at high speed, separating the water from the solids. The water is then reused in drilling. EnCana drilled about 200 oil wells in the Suffield area in 2003. That translates into a reduction of water use equal to the average annual consumption of more than 500 Canadians.

Greenhouse gases – reducing emissions

In the last two years, EnCana has reduced its absolute emissions of greenhouse gases from Canadian operated facilities, despite continued increases in production. How was it done? With solution gas conservation and the improvement of overall operational efficiency. In fact, for every barrel of oil equivalent production, EnCana creates approximately half as many greenhouse gas emissions as its peer group, reflecting EnCana's weighting towards natural gas production. Every year, EnCana participates in the Voluntary Challenge and Registry Report. Please visit the registry's website at www.vci-mrv.ca to view EnCana's latest gold-level submission.

Solution gas – rising recoveries

According to the Alberta Energy and Utilities Board, EnCana's solution gas flaring and venting volumes were fourth highest in Alberta in 2002, reflecting the company's high levels of production. But EnCana has worked diligently over the last several years to maximize the recovery of solution gas at oil properties and now conserves 96.5 percent of solution gas produced. EnCana's recovery exceeds the industry average of 94.7 percent, and ranks among the best conservation rates in the business.

Safety – reducing incidents

EnCana's safety record is improving. Between 2001 and 2003, the frequency of total recordable incidents fell from 2.48 to 1.70 incidents per 200,000 hours worked. This compares favourably with the 2002 industry average of 1.83. Lost-time incidents – when a worker can't return to the job the next day – decreased from 0.48 to 0.45 per 200,000 hours worked. The 2002 industry average was 0.41.

Stakeholder Engagement

EnCana recognizes that effective stakeholder engagement is critical to operating successfully, and that it contributes to a positive corporate reputation. EnCana is committed to timely and meaningful dialogue with stakeholders in a manner that is clear, honest and respectful.

Ekwan Pipeline

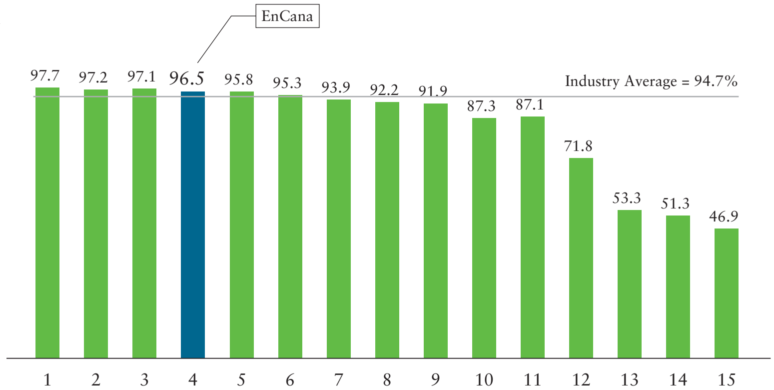
During 2003, EnCana completed the project design and regulatory approval process for the 80-kilometre, 24-inch diameter Ekwan natural gas pipeline from northeastern British Columbia to Alberta. Using a proactive multi-stakeholder engagement approach, EnCana addressed stakeholder concerns in advance of the regulatory process, which resulted in a 51-day project approval turnaround – a record. To achieve this result, EnCana worked closely with First Nations groups, local communities

EnCana is committed to timely and meaningful dialogue with stakeholders in a manner that is clear, honest and respectful.

SOLUTION GAS CONSERVATION IN ALBERTA (2002)

% Conserved

EnCana is striving to reduce emissions.



EnCana pursues local capacity-building initiatives, mutually beneficial relationships and collaborative, consultative and partnership approaches to its community investment and development programs.

and residents, and the provincial and federal governments to anticipate stakeholder concerns and address them in advance of the regulatory process. These concerns included potential impacts to the local environment, use of the right-of-way for increased public access and employment opportunities for local First Nations.

North American aboriginal engagement

EnCana's relations with aboriginal communities flourished in 2003. A focus on increasing aboriginal involvement in business ventures, environmental assessments, training and employment initiatives generated mutual benefits and external recognition.

EnCana was recognized in 2003 for its Aboriginal Relations program. Indian and Northern Affairs Canada and the Alberta Chamber of Commerce recognized EnCana as having the Best Practice in Aboriginal Relations in 2003. EnCana's Alaska/Mackenzie Delta team was singled out for a corporate leadership award by the U.S. Minerals Management Service. The Alaska/Mackenzie Delta team was lauded for its sensitive approach to a drilling project in Inuit whaling grounds in the Beaufort Sea. The project's success is based on an extensive consultation process with regulators, environmental stakeholders and local native communities.

Socio-economic and Community Development

EnCana is committed to making a positive difference in the communities and regions where it does business. EnCana pursues local capacity-building initiatives, mutually beneficial relationships and collaborative, consultative and partnership approaches to its community investment and development programs.

Building community capacity in Ecuador

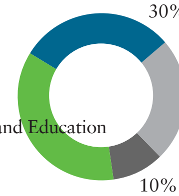
In 2003, EnCanEcuador continued to enhance its capacity-building initiatives. Since 2001, an EnCanEcuador sponsored health program has helped cut the incidence of malaria by half in areas where the company operates. EnCanEcuador is also supporting three agriculture and forestry ventures. Entrepreneurial community organizations are providing revegetation and reforestation services, rights-of-way maintenance and solid-waste management services. An integrated farm project helps farmers improve family income through more diverse and effective use of their land. Owners provide seeds to local farmers, and a community enterprise purchases farm products. A reforestation project that plants jacaranda and mahogany trees has expanded with an enterprise that will work with governments and third parties to develop future pulp and paper production.

Back to basics

In some parts of the world, getting a drink of water isn't as simple as turning on a tap. In Ecuador, EnCana is proud to support the Centre for Affordable Water and Sanitation Technology (CAWST), Canadian experts in developing and distributing Biosand concrete water filtration technology, a low-cost water treatment technology specially designed for use in developing countries. The Biosand concrete filters are household filters made by local people using materials commonly found in most parts of the world. CAWST facilitated the distribution of 50,000 biosand water filters to more than 40 countries, impacting the lives of nearly a million people around the world.

2003 COMMUNITY INVESTMENT
$7.5 million

EnCana is making a positive impact in the community.



Community investment
In 2003, EnCana invested more than $7.5 million in charitable organizations and communities where it operates in Canada and internationally. EnCana subscribes to the Imagine program, through the Canadian Centre for Philanthropy, which sets a benchmark for corporate giving of 1 percent of pre-tax profits. EnCana's goal is to be a neighbour of choice in all communities where it operates. EnCana's program supports innovative ideas and partnerships that benefit non-profit organizations and communities that address today's challenges in the capacity-building aspects of community development, environment, health and wellness and youth and education.

Investing in tomorrow's workers, today
By supporting educational initiatives, EnCana is taking steps to address the growing shortage of skilled workers, a serious issue facing the oil and gas industry. In 2003, EnCana donated $750,000 to the Northern Alberta Institute of Technology (NAIT) to foster the development of the new aboriginal student centre and the design of two mobile education units. Specialized training in a number of programs can be delivered with the mobile units, literally taking learning from the classroom to the community. NAIT President, Dr. Sam Shaw, says 40 percent of Alberta's workforce is expected to retire in 10 years. The province's economic growth depends on an ability to educate people from all communities, cultures and backgrounds – and EnCana's leadership gift is an important contribution to that effort.

Bullying prevention
Through Dare to Care: Bully Proofing Your School, EnCana is helping students, teachers and parents address an overlooked and enduring youth problem by building bullying awareness, supporting victims, creating safer schools and turning bullies into caring kids.

Inquiring minds
Every year, young scientists from across Canada gather at the Canada-Wide Science Fair to compete for prizes, learn from their peers and network with researchers. EnCana supports the Canada-Wide Science Fair with significant prizes and also supports regional fairs in communities where the company operates. By encouraging youth with their scientific investigations, EnCana is fostering the creativity and originality that will contribute to the development of the oil and gas industry in years to come.

Planning for good health
A healthy workforce contributes to the bottom-line. EnCana promotes good health as a core value and encourages employees to maintain a healthy lifestyle. At the EnCana Wellness Centre, located at Calgary's Mount Royal College, the campus community and general public have access to services that provide an innovative and holistic approach to managing personal wellness. A founding sponsor, EnCana also continues to support the Integrative Health Institute's vision to become the recognized leader of evidence-based information, education and research on integrative health and a catalyst for change. In 2003, EnCana took a unique fund-raising approach by donating more than $450,000 collected from the auction of 125 pieces of historical and valuable art by many of Canada's most celebrated landscape and contemporary artists.

Chairman's Message

GOOD GOVERNANCE MATTERS

"We are committed to continuous improvement in corporate governance and have implemented changes to ensure we are in line with current best practices."

DAVID P. O'BRIEN

CORPORATE GOVERNANCE PRACTICES

As EnCana Corporation's Board of Directors, our goal is to increase shareholder value within a framework of integrity and trust. The Board's functions are clearly outlined in a Statement of Corporate Governance Practices, included in the Information Circular dated March 5, 2004 and available at www.encana.com.

Your Board is committed to working with management to realize EnCana's enormous potential. We firmly support Gwyn Morgan, the management team and all EnCanans for their steadfast focus on increasing intrinsic value on a per-share basis. Although EnCana's 2003 share price performance only ranked near the middle of its North American peer group, we are pleased with the progress management and employees have made in achieving operating and financial objectives, refining the strategic focus and further strengthening EnCana's asset base. We remain confident in the corporate strategy and management's ability to deliver strong results for shareholders over the next several years.

In 2003, the Board approved the company's Corporate Constitution. This creates the foundation for building a high performance, principled corporation. Simply stated, our vision is to create a truly great company.

To become a great company, we must also uphold the highest standards of shareholder and public confidence. As you know, corporate governance has become a hot topic. Your Board takes its corporate governance responsibilities very seriously. We review and update corporate governance best practices, ensure processes are in place to address compliance and disclosure matters, and firmly uphold the principles of transparency, financial integrity and fair management compensation.

The Board's commitment to maintaining the highest level of corporate governance is reflected in its organization and responsibilities:

Independence of the Board of Directors

Fifteen of the Board's 16 members are independent of company management. They bring to their duties a wide range of skills and the wealth of experience needed to oversee and challenge the company's management.

Independent Reserves Committee

This Board committee provides an intense scrutiny of the company's core asset, a scrutiny essential to maintaining shareholder confidence. The Board also strongly supports and supervises the process for the full external evaluation of the company's entire reserves on a yearly basis.

Approval of Management's Strategic Plan and Budget

The Board undertakes an in-depth, annual review of this plan, approving the company's broad strategic and financial objectives, in collaboration with management, and continuously monitoring the company's progress towards its stated goals.

DIFFERENCES IN ENCANA'S CORPORATE GOVERNANCE PRACTICES COMPARED TO NYSE CORPORATE GOVERNANCE STANDARDS

AS A CANADIAN COMPANY LISTED ON THE NEW YORK STOCK EXCHANGE ("NYSE"), ENCANA IS NOT REQUIRED TO COMPLY WITH MOST OF THE NYSE CORPORATE GOVERNANCE LISTING STANDARDS AND INSTEAD MAY COMPLY WITH CANADIAN CORPORATE GOVERNANCE PRACTICES. ENCANA IS, HOWEVER, REQUIRED TO DISCLOSE THE SIGNIFICANT DIFFERENCES BETWEEN ITS CORPORATE GOVERNANCE PRACTICES AND THE NYSE CORPORATE GOVERNANCE STANDARDS. A SUMMARY OF THE SIGNIFICANT DIFFERENCES BETWEEN ENCANA'S CORPORATE GOVERNANCE PRACTICES AND THOSE CONTAINED IN THE NYSE RULES IS AVAILABLE ON ENCANA'S WEB SITE (WWW.ENCANA.COM). EXCEPT AS DESCRIBED IN THIS SUMMARY, ENCANA IS IN COMPLIANCE WITH THE NYSE CORPORATE GOVERNANCE STANDARDS IN ALL SIGNIFICANT RESPECTS.

Implementation of Appropriate Systems to Monitor Financial Performance and Manage Risk

The Board regularly monitors the company's operating and financial performance against specific budgetary and key performance measures. It ensures that a system is in place to identify the principal risks to the company and that the appropriate procedures are in place to address them.

Integrity of EnCana's disclosure and internal controls

The Board ensures that processes are in place to address applicable regulatory, corporate, securities and other compliance matters and that an adequate system of disclosure controls and internal control over financial reporting exists.

Policies governing employee behavior

The Board oversees the company's communications policies to provide a framework for consistent behavior of management and employees. Policies and guidelines regarding disclosure of information, insider trading, ethics, business conduct, corporate responsibility and environment, health and safety have been established and disseminated throughout the organization.

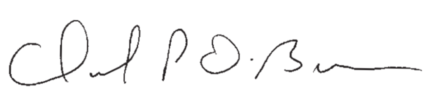
EnCana is also taking new measures to maintain shareholder confidence and ensure the highest standards of accountability are met. The company's new performance share unit compensation plan, for example, directly ties management and employee compensation to total shareholder return, as measured by the company's performance against a North American peer group. Minimum standards for share ownership by all Board members and executive management are also in place.

As well, the United States Sarbanes-Oxley Act of 2002 (SOX) has imposed new requirements to enhance corporate governance practices. EnCana complies with all applicable SOX requirements and will continue to do so as new rules are introduced. The Board welcomes this opportunity to demonstrate EnCana's commitment to the principles of transparency and financial integrity that underlie the SOX legislation.

The Board of Directors is pleased to welcome two new members. Jane Peverett, with her extensive financial experience, joined the Board in July 2003. She is the Chief Financial Officer for British Columbia Transmission Corporation and a member of EnCana's Audit Committee. Ralph Cunningham joined in October 2003, bringing many years of energy industry experience, particularly in the downstream sector. He is a member of our Human Resources and Compensation Committee and the Corporate Responsibility, Environment, Health and Safety Committee.

We have built a strong foundation and we believe EnCana has the potential to produce sustained profitable growth for years to come.

On behalf of the
Board of Directors,

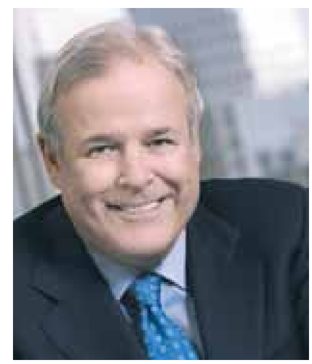


DAVID P. O'BRIEN
Chairman,
EnCana Corporation

DAVID P. O'BRIEN

Chairman

EnCana Corporation



Earnings $2.4

cash flow per share up 68%

EARNINGS PER SHARE

Growing sales and higher commodity prices generate strong earnings growth.

NET CAPITAL INVESTMENT

EnCana invests in an abundant and vast supply of profitable opportunities.

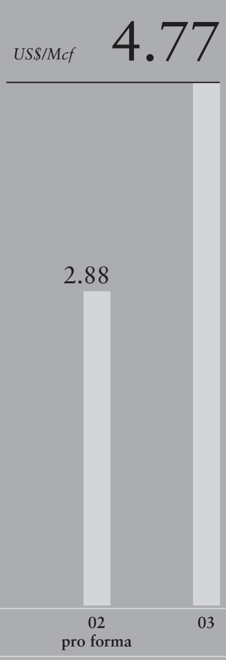
$4.5 Billion

Billion

Capital Discipline

AVERAGE
GAS PRICE

Strong North American demand combined with weak supply boosts 2003 gas price.



AVERAGE
LIQUIDS PRICE

Worldwide concerns about oil supply drive 2003 oil prices.

DEBT-TO-
CAPITALIZATION

EnCana's balance sheet remains one of the strongest among North American independents.

Debt-to-Capitalization 34%

cash flow

Advisories

NOTE REGARDING FORWARD-LOOKING STATEMENTS

ADVISORY – In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this Annual Report constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Report include, but are not limited to, statements with respect to: production and production growth estimates for BOE equivalent, crude oil, natural gas and NGLs for 2004 and beyond; projections relating to the Company's future production and percentage of future production from resource plays; predicted characteristics of resource play formations, including production, recovery and decline rates, timing, costs, reserves additions, efficiencies and returns on investment; projected reserves and production growth over the next five years; projected volatility of commodity prices in 2004 and beyond and certain factors impacting future commodity prices including weather and economic activity levels; the Company's projected risk profile, including country risk, over the next 5 years; projections with respect to future industry decline rates and replacement costs in North America and other areas; potential increases in return on capital and intrinsic value creation; the impact of long-term employee incentives; the Company's oilsands strategy, projected production, production growth and reserves growth available therefrom in 2004 and beyond and projected improvements in SAGD steam-oil ratios; production and growth projections for Ecuador for 2004; projections for the Pelican Lake waterflood project, including future production, production growth, reserves, operating costs, and recovery rates; the timing for completion of the various phases of the Countess, Wild Goose and Starks gas storage projects, and storage capacities, injection and withdrawal rates expected upon completion; projected future market demand for gas storage; the production and growth potential, including the Company's plans therefore, with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential new ventures exploration growth platforms; the projected date for first oil from the Buzzard project and projected production rates thereafter; the potential for acquisitions, the disposition of non-core assets and the expansion of storage and other Midstream assets; the Company's drilling plans for 2004; projected production and reserves growth available from the Company's coalbed methane projects; the Company's projected capital investment levels for 2004 and the source of funding therefore; the upside potential available from the Company's international and new ventures exploration programs; projections with respect to the sufficiency of the Company's credit facilities and forecasted capital resources to support planned capital investment programs and projected financial requirements; the Company's projected ability to extend its debt program on an ongoing basis; the impact of posting crude oil prices; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's plans for the execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; the impact of the Kyoto Accord and similar initiatives in the U.S.A. on operating costs; proved oil and gas reserves and reserve life index projections; the impact of safety and environmental risk management programs; projected net earnings and cash flow sensitivity to changes in commodity prices for 2004; projected tax rates and projected cash taxes payable for 2004 and the assumptions on which they are based; the Company's proposed charitable donations for 2004; the impact on 2004 natural gas production of regulatory rulings and the impact of pipeline rate increases on AECO basis prices in 2004 and beyond.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable reserves; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the Company and its subsidiaries' operate, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the Company and its subsidiaries; the risk that the anticipated synergies to be realized by the merger of Alberta Energy Company Ltd. ("AEC") and the Company will not be realized; costs relating to the merger of AEC and the Company being higher than anticipated and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or which otherwise refer to the existence or possible existence of, or quantities of, oil, natural gas, NGLs or other petroleum substances which have not yet been produced are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that such reserves and/or substances described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this Annual Report are made as of the date of this Annual Report, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this Annual Report are expressly qualified by this cautionary statement.

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

ADVISORY – The reserves and other oil and gas information contained in this Annual Report has been prepared in accordance with U.S. disclosure standards, in reliance on an exemption from the Canadian disclosure standards granted to EnCana by Canadian securities regulatory authorities. Such information may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101"). The reserves quantities disclosed in this Annual Report represent net proved reserves calculated on a constant price basis using the standards contained in U.S. Regulation S-X.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101) differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment.

The finding, development and acquisition costs per BOE in this Annual Report have been calculated by dividing total capital expended on finding, development and acquisition activities by additions to proved reserves, before divestitures, which are the sum of revisions, extensions and discoveries and acquisitions. This calculation is commonly used in the U.S. EnCana's average finding, development and acquisition cost per BOE for its three most recent financial years was $8.35 (combining the results of the Company and AEC for periods prior to the merger).

In this Annual Report, certain natural gas volumes have been converted to barrels of oil equivalent (BOEs) on the basis of six thousand cubic feet (mcf) to one barrel (bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

Natural gas volumes are sold based on heat content or in millions of British Thermal Units ("MMBtu") but physically measured in thousands of cubic feet. The average heat content per cubic foot of EnCana's natural gas is approximately 1,040 Btu or a conversion ratio of 1 mcf = 1.040 MMBtu.

Financials

RESULTS MATTER

JOHN WATSON

Executive Vice-President &

Chief Financial Officer

"We have a very disciplined approach to our business as evidenced by our conservative capital structure, our risk management program and our share repurchase program."

STRENGTH AND LIQUIDITY

Maintaining financial strength and liquidity underpins EnCana's future and its pursuit of an average 10 percent per share annual production growth. The company's balance sheet remained strong in 2003. At year-end 2003, debt-to-capitalization was 34 percent, and debt-to-EBITDA (earnings before interest, taxes, depreciation and amortization) was 1.3 times.

Throughout a series of strategic initiatives in 2003, a strong balance sheet has remained an EnCana hallmark. Early in 2003, the company sold two major pipelines for total consideration of $1 billion and by mid-year sold its 13.75 percent Syncrude interest for consideration of approximately $1 billion. About $870 million was reinvested in share purchases, reducing common shares outstanding by 23.8 million to 460.6 million.

EnCana entered the U.S. capital markets issuing a 10-year note that was marked with the distinction of being the lowest coupon and spread over Treasuries for a 10-year note issue of either predecessor company. At a 4.75% coupon, EnCana's issue was substantially oversubscribed and raised $500 million. EnCana holds investment grade credit ratings and at December 31, 2003 had a $3.1 billion credit facility with a syndicate of major banks and lending institutions, of which more than $1.3 billion was unutilized.

In 2003, EnCana's financial team maintained its focus on providing a high level of disclosure and transparency in its financial reporting. The team administered the company's balance sheet, secured funds to compete directly with international oil and gas producers and reduced the cost of its long-term debt, which is about 52 percent U.S. dollar denominated. This is the strong financial footing upon which EnCana is able to pursue growth and returns.

MD&A

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the audited annual Consolidated Financial Statements ("Consolidated Financial Statements") and accompanying notes on pages 73 to 114. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") in the currency of the United States (except where indicated as being in another currency). A reconciliation to United States generally accepted accounting principles is included in Note 20 to the Consolidated Financial Statements. This MD&A is dated February 6, 2004.

OVERVIEW

U.S. DOLLAR AND U.S. PROTOCOL REPORTING

The audited Consolidated Financial Statements, including the 2001 and 2002 comparative figures, have been presented in United States dollars ("U.S. dollars"). The Company has adopted the U.S. dollar as its reporting currency since most of its revenues are closely tied to the U.S. dollar and to facilitate direct comparisons to other North American upstream exploration and development companies. In this MD&A, all references to $ are to the U.S. dollar. References to C$ are to the Canadian dollar.

In this MD&A and in the supplementary information to the audited Consolidated Financial Statements, reserves quantities, production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting.

Changing the reporting currency affects the presentation in the Company's Consolidated Financial Statements, but not the underlying accounting records. The functional currency of the Company, and its subsidiaries, remains Canadian dollars for Canadian legal entities and U.S. dollars and pounds sterling for non-Canadian legal entities. The financial results of Canadian and United Kingdom ("U.K.") legal entities have been translated into U.S. dollars as described in Notes 1 and 2 of the Consolidated Financial Statements.

Impacts on results due to the change in the U.S./Canadian dollar exchange rate in prior periods have been significant when analyzing specific components of the Canadian business contained in the Consolidated Financial Statements. The stronger Canadian dollar resulted in gains on U.S. dollar denominated long-term debt borrowed in Canada, but adversely affected the reported U.S. dollar costs of operating, capital expenditures and depreciation, depletion and amortization ("DD&A") denominated in Canadian dollars. Since commodity prices received are based on U.S. dollars, or on Canadian dollar prices which are closely tied to the U.S. dollar, revenues for the Company were relatively unaffected by the exchange rate change.

BUSINESS SEGMENTS

EnCana reports the results of its continuing operations under two main business segments: Upstream and Midstream & Marketing. Upstream includes the Company's exploration for, as well as development and production of, natural gas, natural gas liquids ("NGLs"), crude oil and other related activities. Upstream operations are divided into producing and other activities. Producing activities are further segmented by geography and product type. Natural gas and NGLs are principally produced in Canada, the United States, and the U.K. central North Sea. Crude oil is principally produced in North America (primarily Canada), Ecuador and the U.K. central North Sea. International New Ventures Exploration is mainly focused on exploration opportunities in Africa, South America and the Middle East and is included under "Other" activities. Other activities also include third party gas processing, gas gathering and electrical generation associated with producing activities. The Midstream & Marketing segment includes natural gas storage operations, NGLs processing, power generating operations and marketing activities. These marketing activities include the sale and delivery of produced product and the purchase of third party product primarily for the optimization of the Midstream assets as well as the optimization of transportation arrangements not fully utilized for the Company's own production.

BUSINESS ENVIRONMENT

Commodity Price and Foreign Exchange Benchmarks

(average for the year unless otherwise noted)	2003	2003 vs 2002	2002	2002 vs 2001	2001
AECO Price *(C$ per thousand cubic feet)*	$ 6.70	65%	$ 4.07	–35%	$ 6.30
NYMEX Price *($ per million British thermal units)*	5.39	67%	3.22	–25%	4.27
AECO/NYMEX Basis Differential *($ per million British thermal units)*	0.65	–2%	0.66	128%	0.29
WTI *($ per barrel)*	30.99	19%	26.15	1%	25.95
WTI/Bow River Differential *($ per barrel)*	8.01	35%	5.93	–40%	9.87
WTI/OCP NAPO Differential (Ecuador) *($ per barrel)* (1)	8.06	–	–	–	–
WTI/Oriente Differential (Ecuador) *($ per barrel)*	5.59	34%	4.16	–41%	7.02
U.S./Canadian Dollar Year End Exchange Rate	0.774	22%	0.633	1%	0.628
U.S./Canadian Dollar Average Exchange Rate	0.716	12%	0.637	–1%	0.646

(1) This reference price was not available previously and represents the average differential for the period of September (OCP Pipeline shipment commencement) to December 2003.

Natural gas prices rebounded in 2003 from weaker prices experienced in 2002. Continuing concerns about overall North American storage inventory levels, cooler than normal temperatures experienced in the fourth quarter and a lack of confidence concerning prospects for North American supply growth resulted in an increase in the average New York Mercantile Exchange ("NYMEX") price of 67 percent in 2003 when compared to 2002. The average NYMEX gas price in the fourth quarter of 2003 was $4.58 per MMBtu, an increase of 15 percent over the fourth quarter price in 2002 of $3.98 per MMBtu. Lower gas prices in 2002 were the result of high levels of natural gas in storage from decreased demand. The AECO/NYMEX basis differential in the fourth quarter of 2003 averaged $0.37 per MMBtu below NYMEX. This represented an improvement of $0.26 per MMBtu over the average in the same period in 2002 of $0.63 per MMBtu. The improvement in the basis differential can be attributed to a stronger Canadian dollar and higher prices for the portion of sales volumes transported from Alberta to Eastern Canada.

In 2003, EnCana sold approximately 47 percent of its produced natural gas at fixed prices, approximately 9 percent at AECO Index based pricing, approximately 39 percent at NYMEX based pricing and approximately 5 percent at other prices. As of December 31, 2003, the Company had arranged for the sale of its projected 2004 natural gas production of approximately 45 percent at fixed prices, approximately 9 percent at AECO Index based prices, approximately 42 percent at NYMEX based prices and approximately 4 percent at other prices.

World crude oil prices increased significantly in 2003 over 2002 and 2001 as supply disruptions in Venezuela and Nigeria preceded the invasion of Iraq. The slow return of Iraqi oil production and OPEC's successful production management combined with strong Asian demand kept crude oil inventories low with resulting upward pressure on prices. The benchmark West Texas Intermediate ("WTI") crude oil price of $31.16 per barrel in the fourth quarter of 2003 was $2.93 higher than the $28.23 per barrel in the fourth quarter of 2002.

Canadian heavy oil differentials, as evidenced by the WTI/Bow River differential, widened in absolute terms in 2003 compared to 2002. The widening is primarily due to the higher price for WTI. As a percentage of WTI, Bow River's average sales price for 2003 was 74 percent of WTI as compared to 77 percent in 2002. In 2001, Canadian heavy oil differentials were very wide due to refinery problems and narrowed in 2002 as those problems were rectified.

Ecuador's Oriente differential also widened in 2003 compared to 2002 as a result of the increase in WTI prices. In September 2003, the OCP Pipeline became operational resulting in the creation of a new Ecuadorian crude called NAPO blend. NAPO blend is a heavier crude than Oriente and therefore has a wider differential to WTI.

The 2003 year end U.S./Canadian dollar exchange rate increased by 22 percent when compared to 2002 and was $0.774 per $1 Canadian at December 31, 2003 compared to $0.633 and $0.628 at the end of 2002 and 2001 respectively. The change from 2002 was primarily the result of the economic slowdown in the U.S., continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit.

MANAGEMENT STRATEGY

Upstream capital investment programs are principally focused on growing reserves and production in North American resource plays where the Company believes it has a competitive advantage through exploitation of existing resource holdings in strategic gas developments at Greater Sierra and Cutbank Ridge in British Columbia, Southern Alberta, Jonah and Mamm Creek in the U.S. Rockies as well as oil development at Foster Creek, Pelican Lake and Suffield. In addition to Ecuador, the development of discoveries in the U.K. central North Sea and the Gulf of Mexico are expected to add further to oil growth. Additional upside potential exists in the East Coast of Canada and international exploration activities. Midstream opportunities are focused on expansion and development of the Company's North American gas storage business.

The success of these strategies is subject to numerous risk factors such as (including but not limited to) fluctuations in commodity prices, foreign exchange rates and interest rates, in addition to credit, operational and safety and environmental risks. A number of these risks have been partially mitigated through the risk management program detailed in Note 17 of the Consolidated Financial Statements and discussed in the Risk Management section of this MD&A.

2003 VERSUS 2002 COMPARATIVES

The 2002 comparative figures included in the Consolidated Financial Statements for the year ended December 31, 2003 exclude the results of Alberta Energy Company Ltd. ("AEC") prior to the April 5, 2002 merger ("Merger") with AEC.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary *($ millions, except per share amounts)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	**$ 10,216**	**63%**	$6,276	93%	$ 3,244
Net Earnings from Continuing Operations	**2,167**	**195%**	735	–12%	832
– per share – basic	**4.57**	**160%**	1.76	–46%	3.26
– per share – diluted	**4.52**	**160%**	1.74	–46%	3.21
Net Earnings	**2,360**	**191%**	812	–5%	854
– per share – basic	**4.98**	**157%**	1.94	–42%	3.34
– per share – diluted	**4.92**	**156%**	1.92	–42%	3.30
Cash Flow from Continuing Operations	**4,420**	**95%**	2,267	55%	1,463
– per share – basic	**9.32**	**72%**	5.43	–5%	5.72
– per share – diluted	**9.21**	**72%**	5.36	–5%	5.65
Cash Flow	**4,459**	**84%**	2,419	62%	1,494
– per share – basic	**9.41**	**63%**	5.79	–1%	5.85
– per share – diluted	**9.30**	**63%**	5.72	–1%	5.77
Total Assets	**24,110**	**21%**	19,912	192%	6,823
Long-Term Debt	**6,088**	**21%**	5,051	244%	1,467
Cash Dividends (1)	**139**	**29%**	108	–87%	818

(1) Represents cash dividends paid to common shareholders at the rate of C$0.40 per share annually. 2001 also includes a special dividend paid to common shareholders of C$4.60 per share as part of the reorganization of Canadian Pacific Limited, the former principal shareholder of the Company's predecessor, PanCanadian Petroleum Ltd.

Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic and Cash Flow per share-diluted are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management utilizes Cash Flow and Cash Flow from Continuing Operations as key measures to assess the ability of the Company to finance operating activities and capital expenditures.

EnCana's cash flow from continuing operations and net earnings from continuing operations increased 95 percent and 195 percent respectively compared to 2002 as a result of growth in sales volumes, higher commodity prices and the inclusion of a full year of post Merger operations, partially offset by increased expenses.

Net earnings for the year also included an unrealized after-tax gain on the U.S. dollar denominated debt issued in Canada of $433 million, or $0.90 per diluted share resulting from the increase in the value of the Canadian dollar versus the U.S. dollar, and a $359 million, or $0.75 per diluted share recovery of future income taxes resulting from reductions in the Canadian federal and Alberta corporate income tax rates. Impacts on results due to the change in the U.S./Canadian dollar exchange rate have been significant when analyzing specific components contained in the Consolidated Financial Statements. For every 100 dollars denominated in Canadian currency spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs, as reported in U.S. dollars, of approximately $7.90 based on the increase in the average U.S./Canadian dollar exchange rate in 2003 of $0.716 over 2002 of $0.637. Revenues for the Company were relatively unaffected by the increased exchange rate since commodity prices received are based in U.S. dollars or in Canadian dollar prices which are closely tied to the U.S. dollar.

2002 VERSUS 2001

Cash flow from continuing operations and net earnings from continuing operations in 2002 increased 55 percent and decreased 12 percent respectively compared to 2001. The cash flow increase was due to the inclusion of nine months of post Merger results in 2002, reduced operating costs associated with crude oil production, partially offset by reduced natural gas prices. The net earnings drop was the result of weaker natural gas prices, increased depreciation, depletion and amortization rates resulting from the Merger, partially offset by increased sales volumes resulting from the Merger and the Company's expansion of its North American operations.

Earnings from Continuing Operations Excluding Unrealized Foreign Exchange on Translation of Canadian Issued U.S. Dollar Debt (After Tax) and Tax Rate Reductions

The following table has been prepared in order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt issued in Canada and the effect of the reduction in the Canadian and Alberta tax rates on the Company's results. The majority of these unrealized gains/losses on U.S. dollar debt issued in Canada relate to debt with maturity dates in excess of 5 years. In accordance with Canadian GAAP, the Company is required to translate U.S. dollar denominated long-term debt issued in Canada into Canadian dollars at the period end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Canadian GAAP also requires the Company to recognize impacts of tax rate changes that are substantively enacted. Gains or losses from these changes are also recorded in the Consolidated Statement of Earnings and included as an adjustment to Future Income Taxes in the Consolidated Balance Sheet.

($ millions)	2003	2002	2001
Net Earnings from Continuing Operations, as reported	$ **2,167**	$ 735	$ 832
Deduct: Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt (after-tax) (1)	**433**	17	(28)
Deduct: Future tax recovery due to tax rate reductions (2)	**359**	20	53
Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after-tax) and tax rate reductions	$ **1,375**	$ 698	$ 807

($ per Common Share – Diluted			
Net Earnings from Continuing Operations, as reported	$ **4.52**	$ 1.74	$ 3.21
Deduct: Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt (after-tax) (1)	**0.90**	0.04	(0.11)
Deduct: Future tax recovery due to tax rate reductions (2)	**0.75**	0.05	0.20
Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after-tax) and tax rate reductions	$ **2.87**	$ 1.65	$ 3.12

(1) Unrealized gain (loss) has no impact on cash flow.

(2) Future tax adjustments have no impact on cash flow.

Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after tax) and tax rate reductions is not a measure that has any standardized meaning prescribed by Canadian GAAP and is considered a non-GAAP measure. Therefore, this measure may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company's finances and results of operations. Management believes items such as foreign exchange gains and losses or tax rate reductions distort results and reduce comparability of the Company's underlying financial performance between periods.

Quarterly results were as follows:

2003 and 2002 Quarterly Summary

	2003				2002			
($ millions, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1*
Revenues, Net of Royalties	**$ 2,850**	**$ 2,291**	**$ 2,332**	**$ 2,743**	$ 2,116	$ 1,780	$ 1,693	$ 687
Net Earnings from Continuing Operations	**426**	**286**	**805**	**650**	248	79	318	90
– per share – basic	**0.92**	**0.60**	**1.67**	**1.35**	0.52	0.17	0.69	0.35
– per share – diluted	**0.91**	**0.60**	**1.66**	**1.34**	0.51	0.16	0.68	0.35
Net Earnings	**426**	**290**	**807**	**837**	282	136	303	91
– per share – basic	**0.92**	**0.61**	**1.68**	**1.74**	0.59	0.29	0.66	0.36
– per share – diluted	**0.91**	**0.61**	**1.67**	**1.73**	0.58	0.28	0.65	0.35
Cash Flow from Continuing Operations	**1,217**	**973**	**1,039**	**1,191**	874	583	569	241
– per share – basic	**2.63**	**2.06**	**2.16**	**2.48**	1.83	1.22	1.23	0.94
– per share – diluted	**2.61**	**2.04**	**2.14**	**2.46**	1.81	1.21	1.22	0.93
Cash Flow	**1,254**	**977**	**1,007**	**1,221**	935	651	591	242
– per share – basic	**2.71**	**2.06**	**2.10**	**2.54**	1.96	1.37	1.28	0.95
– per share – diluted	**2.69**	**2.04**	**2.08**	**2.52**	1.94	1.35	1.26	0.94

* Excludes the pre-merger results of AEC.

Quarterly results in 2003, as compared to the same periods in 2002, reflect the impacts of increasing commodity prices, increased production volumes, inclusion of a full year of post Merger results and are partially offset by increased expenses. The 2003 after tax unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt of $433 million was reported as $140 million in the first quarter, $168 million in the second quarter, $12 million in the third quarter and $113 million in the fourth quarter. The 2003 future tax recovery due to tax rate reductions of $359 million was recorded in the second quarter.

ACQUISITIONS AND DIVESTITURES

On October 1, 2003, an EnCana U.K. subsidiary became the operator of the Scott and Telford fields in the U.K. central North Sea marking the close of the purchase and sale agreements to exchange the 22.5 percent non-operated interest in the Llano oil discovery in the Gulf of Mexico for a 14 percent interest in both the Scott and Telford oil fields. In early 2004, the EnCana U.K. subsidiary completed the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively, for net cash consideration of approximately $126 million. As a result of these acquisitions and the initial ownership interest held, the EnCana U.K. subsidiary now holds a 41 percent interest in the Scott field and a 54.3 percent interest in the Telford field.

On July 18, 2003, an EnCana U.S. subsidiary acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of approximately $91 million. Included in this acquisition were interests in developed and undeveloped reserves and landholdings in Texas, U.S.A. which are currently producing approximately 21 million cubic feet of natural gas per day.

On January 31, 2003, the Company expanded its production and landholdings in Ecuador through the purchase of interests held by Vintage Petroleum Inc. for net cash consideration of approximately $116 million. This acquisition included interests in developed and undeveloped reserves producing approximately 4,000 barrels of oil per day in three blocks adjacent to Block 15, where an EnCana subsidiary has an existing non-operated working interest.

During 2003, the Company acquired and disposed of other properties that had a less significant impact on operations. On a net basis, the total amount of additional acquisitions over dispositions was $183 million. Property acquisitions have been included as part of total capital expenditures as discussed in the Liquidity and Capital Resources section of this MD&A.

DISCONTINUED OPERATIONS

Syncrude

During 2003, subsidiaries of the Company completed the sale of their working interest together with EnCana's gross overriding royalty in the Syncrude Joint Venture for net cash consideration of approximately $1.0 billion (C$1.45 billion). There was no gain or loss recorded on this sale. Net earnings from Syncrude operations were $24 million in 2003. With the sale of the Syncrude interest completed, the Company intends to focus its oilsands strategy on developing its high quality bitumen resources, recovered through producing wells using Steam Assisted Gravity Drainage ("SAGD") technology on 100 percent owned and operated lands at Foster Creek and Christina Lake.

Midstream – Pipelines

Subsidiaries of the Company closed the sale of their interests in the Cold Lake Pipeline System and Express Pipeline System on January 2, 2003 and January 9, 2003, respectively, for total consideration of approximately $1.0 billion (C$1.6 billion), including the assumption of related long-term debt by the purchaser. An after-tax gain on sale of $169 million was recorded in relation to these transactions.

These sales were part of EnCana's strategic realignment to focus on developing its large portfolio of higher return growth assets. The proceeds were used for general corporate purposes, including debt reduction, prior to being re-deployed as discussed in the Liquidity and Capital Resources section of this MD&A.

The Syncrude and Midstream-Pipelines operations described above have been accounted for as discontinued operations as disclosed in Note 5 to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS*

Financial Results *($ millions)*

Year ended December 31	2003 Produced Gas & NGLs (1)	2003 Crude Oil	2003 Other	2003 Total	2002 Produced Gas & NGLs (1)	2002 Crude Oil	2002 Other	2002 Total	2001 Produced Gas & NGLs (1)	2001 Crude Oil	2001 Other	2001 Total
Revenues, Net of Royalties	$ 4,690	$ 1,457	$ 180	$ 6,327	$ 2,440	$ 1,158	$ 76	$ 3,674	$ 1,670	$ 621	$ 24	$ 2,315
Expenses												
Production and Mineral Taxes	160	29	–	189	85	34	–	119	55	22	–	77
Transportation and Selling	370	120	–	490	216	61	–	277	78	22	–	100
Operating	402	401	170	973	290	265	71	626	123	163	8	294
Depreciation, Depletion and Amortization	1,368	669	96	2,133	827	355	51	1,233	292	166	20	478
Upstream Income	$ 2,390	$ 238	$ (86)	$ 2,542	$ 1,022	$ 443	$ (46)	$ 1,419	$ 1,122	$ 248	$ (4)	$ 1,366

* Upstream results exclude Syncrude operations which have been accounted for as discontinued operations as described in Note 5 to the Consolidated Financial Statements.

(1) NGL results includes Condensate.

Sales Volumes

(After Royalties)	2003	2003 vs 2002	2002	2002 vs 2001	2001
Produced Gas *(million cubic feet per day)*	**2,566**	**25%**	2,058	105%	1,005
Crude Oil *(barrels per day)*	**198,078**	**26%**	156,691	72%	91,093
NGLs *(barrels per day)*	**24,466**	**16%**	21,054	60%	13,126
Continuing Operations *(barrels of oil equivalent per day)* (1)	**650,211**	**25%**	520,745	92%	271,719
Syncrude *(barrels per day)*	**7,629**	**–68%**	23,540	–	–
Total *(barrels of oil equivalent per day)* (1)	**657,840**	**21%**	544,285	100%	271,719

(1) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

Revenue Variance (1)

($ millions)	2003 compared to 2002 Price	2003 compared to 2002 Volume	2003 compared to 2002 Total	2002 compared to 2001 Price	2002 compared to 2001 Volume	2002 compared to 2001 Total
Produced Gas and NGLs	**$ 1,336**	**$ 914**	**$ 2,250**	$ (459)	$ 1,229	$ 770
Crude Oil	**(5)**	**304**	**299**	52	485	537
Other			**104**			52
Total Revenue, Net of Royalties	**$ 1,331**	**$ 1,218**	**$ 2,653**	$ (407)	$ 1,714	$ 1,359

(1) Includes continuing operations only.

CONSOLIDATED UPSTREAM RESULTS

The Company's 2003 Upstream revenues, net of royalties, increased $2,653 million, or 72 percent, over 2002 due to the increase in commodity prices, growth in sales volumes and the inclusion of a full year of post Merger results. The revenue variance table shows the 2003 increase over 2002 to be approximately 50 percent volume and 50 percent price related. The 25 percent growth in barrels of oil equivalent sales volumes from continuing operations, compared to 2002, reflected increased production in the U.S. Rockies, the addition of a full year of post Merger volumes, the removal of transportation capacity restrictions in Ecuador as a result of the completion of the OCP Pipeline and the expansion of production from the Company's SAGD projects.

Production and mineral tax increases in 2003 are the result of higher prices in the U.S. and Ecuador and a full year of post Merger results.

The increased expenditures for transportation and selling in 2003 are attributable to growth in North American volumes, increases in Ecuador volumes as a result of the commencement of shipments on the OCP Pipeline, a full year of post Merger results and the effect of the change in the U.S./Canadian dollar exchange rate on Canadian transportation and selling expenses.

Upstream operating costs, excluding costs related to Other activities, increased 45 percent compared to 2002, and 94 percent when comparing 2002 to 2001. The increase in 2003 over 2002 is due to additional production volumes, a full year of post Merger results, as well as higher unit operating expenses. Operating expenses from continuing operations, excluding Other activities, were $3.38 per barrel of oil equivalent for 2003 up from $2.92 per barrel of oil equivalent in 2002 and $2.88 per barrel of oil equivalent in 2001. The increase is mainly related to the change in the average U.S./Canadian dollar exchange rate and its impact on Canadian dollar denominated operating expenses, as well as increased costs for maintenance, workovers, higher fuel and power expense due to higher natural gas prices and an increased proportionate share of costs from SAGD operations. The increase in 2002 over 2001 resulted primarily from the inclusion of nine months operations from the Merger.

DD&A expense increased 73 percent, or $900 million, compared to 2002 and 158 percent, or $755 million, comparing 2002 to 2001. On a barrel of oil equivalent basis, excluding Other, DD&A rates were $8.58 per barrel for 2003 compared to $6.22 per barrel and $4.62 per barrel in 2002 and 2001 respectively. The increased DD&A rate in 2003 reflects increased future development costs related to the proved reserves added for SAGD projects and the U.S. Rockies, and the effect of the increase in the U.S./Canadian dollar exchange rate on the Canadian DD&A expense. The 2003 future development costs are approximately $1.81 per barrel of oil equivalent of the DD&A rate calculation compared to $0.53 per barrel of oil equivalent in 2002. The higher costs in 2002 compared to 2001 primarily reflected the additional charges associated with the addition of the post Merger assets, which were recorded at their fair value as part of the allocation of the purchase price.

Other activities added $180 million in revenues and $170 million in operating expenses in 2003 and include activities that do not result directly in the production of oil and gas. These activities include revenue from third party gas processing, gas gathering and electrical generation associated with cogeneration of steam. The higher DD&A expense, reflected in Other activities, includes an expense of approximately $103 million for impairments on Upstream international exploration prospects deemed not to be commercially viable, offset by a gain realized on divestiture of an exploration property.

Produced Gas and NGLs (1)

Financial Results – Canada *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	**$ 3,523**	**79%**	$ 1,971	23%	$ 1,598
Expenses					
Production and Mineral Taxes	**52**	**4%**	50	4%	48
Transportation and Selling	**274**	**81%**	151	110%	72
Operating	**342**	**34%**	255	128%	112
Depreciation, Depletion and Amortization	**1,075**	**72%**	625	139%	261
Segment Income	**$ 1,780**	**100%**	$ 890	–19%	$ 1,105
Gas Volume *(million cubic feet per day)*	**1,965**	**15%**	1,711	80%	953
NGL Volume *(barrels per day)*	**14,278**	**3%**	13,852	37%	10,142

(1) NGL results include Condensate.

Financial Results – United States *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	**$ 1,143**	**152%**	$ 454	669%	$ 59
Expenses					
Production and Mineral Taxes	**108**	**209%**	35	400%	7
Transportation and Selling	**86**	**46%**	59	–	–
Operating	**60**	**71%**	35	218%	11
Depreciation, Depletion and Amortization	**293**	**45%**	202	552%	31
Segment Income	**$ 596**	**385%**	$ 123	1130%	$ 10
Gas Volume *(million cubic feet per day)*	**588**	**74%**	337	684%	43
NGL Volume *(barrels per day)*	**9,291**	**45%**	6,407	162%	2,443

(1) NGL results include Condensate.

Financial Results – United Kingdom *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	$ **24**	**60%**	$ 15	15%	$ 13
Expenses					
Production and Mineral Taxes	**–**	**–**	–	–	–
Transportation and Selling	**10**	**67%**	6	–	6
Operating	**–**	**–**	–	–	–
Depreciation, Depletion and Amortization	**–**	**–**	–	–	–
Segment Income	$ **14**	**56%**	$ 9	29%	$ 7
Gas Volume *(million cubic feet per day)*	**13**	**30%**	10	11%	9
NGL Volume *(barrels per day)*	**897**	**13%**	795	47%	541

(1) NGL results include Condensate.

In 2003, revenues, net of royalties from sales of produced gas and NGLs contributed 74 percent of the Company's total Upstream revenue and in total were $2,250 million higher than in 2002. The increase in 2003 revenues net of royalties from produced gas and NGLs over 2002 was due to increased commodity prices, drilling successes in both Canada and the U.S., significant property acquisitions in the U.S. Rockies in 2002 and a full year of post Merger results. Natural gas revenues in 2003 were reduced by a loss of $91 million due to financial currency and commodity hedging activities, compared to a gain of $65 million in 2002 and a gain of $134 million in 2001.

Gas sales from the U.S. have risen 74 percent, or 251 million cubic feet per day, when comparing 2003 to 2002 due to drilling successes and property acquisitions combined with a full year of post Merger results. Canadian gas sales volumes have increased 254 million cubic feet per day primarily due to inclusion of a full year of post Merger operations. 2003 Canadian production gains achieved through resource development were offset by higher than anticipated declines at Ladyfern, divestments in non-core producing areas and weather delays for well tie-ins. Volume increases in 2002 compared to 2001 is due to the inclusion of nine months of post Merger results in 2002.

Per Unit Results – Produced Gas

	Produced Gas – Canada			Produced Gas – U.S.		
($ per thousand cubic feet)	2003	2002	2001	2003	2002	2001
Price, net of royalties	$ **4.87**	$ 2.86	$ 4.06	$ **4.88**	$ 2.96	$ 2.46
Expenses						
Production and mineral taxes	**0.07**	0.08	0.14	**0.47**	0.27	0.49
Transportation and selling	**0.38**	0.24	0.21	**0.40**	0.47	–
Operating	**0.48**	0.41	0.32	**0.28**	0.28	0.68
Netback excluding hedging	$ **3.94**	$ 2.13	$ 3.39	$ **3.73**	$ 1.94	$ 1.29
Financial hedge	**(0.13)**	0.05	0.38	**0.02**	0.29	–
Netback including hedging	$ **3.81**	$ 2.18	$ 3.77	$ **3.75**	$ 2.23	$ 1.29

Per Unit Results – NGLs (1)

	NGLs – Canada			NGLs – U.S.		
($ per barrel)	2003	2002	2001	2003	2002	2001
Price, net of royalties	$ **24.26**	$ 17.55	$ 19.70	$ **26.97**	$ 23.75	$ 22.22
Expenses						
Production and mineral taxes	**–**	–	–	**2.03**	1.02	–
Transportation and selling	**0.17**	–	–	**–**	–	–
Netback	$ **24.09**	$ 17.55	$ 19.70	$ **24.94**	$ 22.73	$ 22.22

(1) NGL results include Condensate.

Average realized prices for natural gas in the U.S. and Canada increased approximately 65 percent and 70 percent respectively in 2003 compared to 2002. Concerns about overall North American storage inventory levels and a lack of confidence concerning prospects for North American supply growth were the primary reasons for the overall increase. Lower realized gas prices in Canada experienced in 2002 compared to 2001 were caused by high levels of natural gas in storage during 2002 resulting from decreased demand. Average realized prices for NGLs in the U.S. and Canada increased approximately 14 percent and 38 percent respectively in 2003 compared to 2002. NGL realized price increases generally resulted from changes in the price of WTI discussed previously in this MD&A.

Per unit production and mineral tax expense for produced gas in the U.S. Rockies was higher in 2003 than 2002 by $0.20 per thousand cubic feet due to higher natural gas prices. Per unit produced gas production and mineral taxes were $0.22 per thousand cubic feet lower in 2002 than in 2001, reflecting the addition of properties attracting lower production and mineral tax rates as a result of the Merger.

For Canadian produced gas operations, per unit transportation and selling costs were higher in 2003 by $0.14 per thousand cubic feet primarily due to an increased proportion of sales transported to more distant markets and the change in the U.S./Canadian dollar exchange rate. Per unit transportation and selling expense in the U.S. decreased $0.07 per thousand cubic feet when compared to 2002 due to shorter average transportation distances to markets.

Per unit operating expenses for Canadian produced gas were higher in 2003 by $0.07 per thousand cubic feet as a result of increased maintenance, workovers, the effect of the change in the U.S./Canadian dollar exchange rate and production from higher operating cost areas. Operating expenses in the U.S. per unit remained flat for 2003 over 2002. Canadian per unit operating expenses were higher in 2002 compared to 2001 reflecting the addition of higher cost operations from the Merger combined with higher processing fees, gathering, maintenance and electricity costs. U.S. per unit operating expenses decreased in 2002 compared to 2001 reflecting the addition of significant lower cost operations and higher production volumes from the Merger.

Crude Oil

Financial Results – North America *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	$ 951	15%	$ 825	58%	$ 523
Expenses					
Production and Mineral Taxes	4	–80%	20	–9%	22
Transportation and Selling	69	97%	35	119%	16
Operating	300	49%	201	31%	153
Depreciation, Depletion and Amortization	436	84%	237	91%	124
Segment Income	$ 142	–57%	$ 332	60%	$ 208
Volumes *(barrels per day)*	142,326	21%	117,218	46%	80,272

Financial Results – Ecuador *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	$ 412	68%	$ 245	–	$ –
Expenses					
Production and Mineral Taxes	25	79%	14	–	–
Transportation and Selling	45	114%	21	–	–
Operating	83	57%	53	–	–
Depreciation, Depletion and Amortization	159	101%	79	–	–
Segment Income	$ 100	28%	$ 78	–	$ –
Volumes *(barrels per day)*	46,521	56%	29,740	–	–

Financial Results – United Kingdom *Year ended December 31 ($ millions)*	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	$ 94	7%	$ 88	–10%	$ 98
Expenses					
Production and Mineral Taxes	–	–	–	–	–
Transportation and Selling	6	20%	5	–17%	6
Operating	18	64%	11	10%	10
Depreciation, Depletion and Amortization	74	90%	39	–7%	42
Segment Income	$ (4)	–112%	$ 33	–18%	$ 40
Volumes *(barrels per day)*	9,231	–5%	9,733	–10%	10,821

In 2003, total revenues, net of royalties for crude oil, increased $299 million, or 26 percent, over 2002. The improvement is attributable to increased production volumes, a full year of post Merger volumes and higher average realized commodity prices offset by increased losses related to financial hedging. Crude oil revenues were reduced by a loss of approximately $206 million resulting from financial commodity and currency hedging. This compares with a loss of $33 million in 2002 and a gain of $20 million in 2001.

North American crude oil sales volumes averaged 142,326 barrels per day compared to 117,218 barrels per day in 2002. The improvement in North American sales volumes reflects the inclusion of a full year of post Merger volumes, increased production at Foster Creek including completion of the Phase 1 expansion and a full year of commercial production at Christina Lake combined with continued development at Suffield and Pelican Lake. Sales volumes in 2002 were higher than 2001 volumes of 80,272 primarily due to the inclusion of nine months of post Merger results.

Ecuador crude oil sales volumes increased by 56 percent in 2003 to 46,521 barrels per day compared to volumes of 29,740 barrels per day in 2002 primarily due to the inclusion of a full year of post Merger volumes and the removal of transportation capacity constraints as a result of the commencement of shipments on the OCP Pipeline in September, partially offset by the requirement to provide line fill for OCP of approximately 3,213 barrels per day. Sales volumes during the fourth quarter of 2003 averaged 77,352 barrels per day compared with 35,900 barrels per day in the same period in 2002. The Company has a shipping commitment of approximately 108,000 barrels per day on the OCP Pipeline and currently does not have transportation capacity constraints on its production. The Company's shipping commitment was based on estimated gross production volumes which included the royalty portion taken in-kind by the Ecuadorian government. The Ecuadorian government subsequently decided to transport its royalty volumes on the SOTE pipeline. As a result of this decision the Company incurs additional transportation costs of approximately $0.80 to $1.10 per barrel on the current level of volumes transported through the OCP Pipeline.

Acquisition of additional interests in the Scott and Telford fields was the major contributor to higher crude oil volumes of 13,665 barrels per day from the U.K. central North Sea in the fourth quarter of 2003 compared to 7,151 barrels per day in the same period in 2002. Crude oil volumes for 2003 averaged 9,231 barrels per day compared to 9,733 barrels per day and 10,821 barrels per day in 2002 and 2001 respectively. The overall decrease in 2003 average volumes resulted from natural declines and unscheduled downtime partially offset by the additional ownership interests.

Per Unit Results – Crude Oil

	North America			Ecuador			United Kingdom		
($ per barrel)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Price, net of royalties	**$ 22.29**	$ 20.08	$ 17.35	**$ 24.21**	$ 22.57	$ –	**$ 28.11**	$ 24.76	$ 24.62
Expenses									
Production and mineral taxes	**0.09**	0.43	0.71	**1.47**	1.24	–	**–**	–	–
Transportation and selling	**1.31**	0.82	0.55	**2.56**	2.00	–	**1.97**	1.69	1.68
Operating	**5.80**	4.69	5.24	**4.84**	4.86	–	**5.09**	3.28	2.69
Netback excluding hedging	**$ 15.09**	$ 14.14	$ 10.85	**$ 15.34**	$ 14.47	$ –	**$ 21.05**	$ 19.79	$ 20.25
Financial hedge	**(3.97)**	(0.76)	0.60	**–**	(0.01)	–	**–**	(0.06)	0.46
Netback including hedging	**$ 11.12**	$ 13.38	$ 11.45	**$ 15.34**	$ 14.46	$ –	**$ 21.05**	$ 19.73	$ 20.71

Average realized crude oil prices in 2003 increased approximately 10 percent over 2002 and approximately 14 percent in 2002 when compared to 2001. Continuing concerns over tensions in the Middle East combined with strong Asian demand and OPEC's management of its production quotas were the primary reasons for the overall increase in 2003 offset by increased crude oil price differentials. The change in 2002 over 2001 reflects the average price weightings of additional volumes from the Merger.

North American per unit production and mineral taxes were $0.09 per barrel compared to $0.43 per barrel in 2002. North American 2003 per unit production and mineral taxes include the impact of mineral tax amendments, related to prior years and recorded in the third quarter of 2003, which reduced mineral taxes by approximately $16 million or $0.30 per barrel. Production and mineral taxes in Ecuador increased $0.23 per barrel, or 19 percent, in 2003 over 2002. This is due to the increased production from the Tarapoa block and higher realized prices from the Tarapoa volumes. The Company is required to pay the Ecuadorian government a percentage of revenue from this block based on realized prices over a base price.

Per unit transportation and selling costs in North America were higher by $0.49 per barrel, or 60 percent, over 2002. The increase resulted primarily from increased heavy crude oil volumes which attract a 20 percent premium transportation charge over light oil combined with annual tariff increases. Compared to 2002, higher per unit transportation and selling costs in Ecuador reflect the higher unit costs on the OCP Pipeline in 2003 compared to the SOTE pipeline system resulting from the ship or pay obligations on the system requiring the Company to pay for a prescribed amount of capacity at a fixed rate. Per unit transportation and selling costs in the U.K. increased 17 percent in 2003 compared to 2002, primarily as a result of the strengthening of the British pound relative to the U.S. dollar.

The increase in North American unit operating expenses for crude oil of $1.11 per barrel over 2002 is attributable to the increase in the U.S./Canadian dollar exchange rate, higher maintenance costs, increased production of heavy oil volumes from SAGD projects at Foster Creek and Christina Lake, combined with higher fuel and electricity costs resulting from the rise in natural gas prices. The U.K. 2003 per unit operating expenses increased 55 percent over 2002 due to unscheduled maintenance costs, acquisition related costs as well as the strengthening of the British pound relative to the U.S. dollar.

Midstream & Marketing Operations Financial Results (1)

($ millions)	Midstream			Marketing			Total		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues	**$ 1,084**	$ 440	$ 154	**$ 2,803**	$ 2,154	$ 777	**$ 3,887**	$ 2,594	$ 931
Expenses									
Transportation and selling	**–**	–	–	**55**	87	11	**55**	87	11
Operating	**261**	174	142	**63**	13	12	**324**	187	154
Purchased product	**762**	169	–	**2,693**	2,031	739	**3,455**	2,200	739
Depreciation, depletion and amortization	**40**	24	9	**8**	12	1	**48**	36	10
	$ 21	$ 73	$ 3	**$ (16)**	$ 11	$ 14	**$ 5**	$ 84	$ 17

(1) Excludes financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

Revenues from continuing Midstream & Marketing operations increased by $1,293 million in 2003 from 2002 due primarily to higher commodity prices and the inclusion of a full year of post Merger results. Despite higher revenues in 2003, financial results were negatively impacted by short-term market factors. Narrower summer/winter price spreads resulted in lower revenues from third-party gas storage contracts and reduced margins from optimization activities. In addition, natural gas processing margins decreased due to relatively higher feedstock prices and reduced seasonal demand for propane. The change in operations between 2002 and 2001 was mostly the result of the addition of AEC midstream assets which included gas storage facilities and natural gas processing to the existing midstream segment.

Midstream operating expenses increased in 2003 due to the inclusion of a full year of post Merger results and the effect of the change in the U.S./Canadian dollar on the Canadian operations as well as he higher cost of natural gas and increased throughput volumes for NGL processing. The higher costs reflected in 2002 over 2001 was due to the inclusion of nine months of post Merger activity.

Marketing Financial Results on a Product Basis (1)

($ millions)	Gas			Crude Oil and NGLs			Total		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues	**$ 1,442**	$ 931	$ 385	**$ 1,361**	$ 1,223	$ 392	**$ 2,803**	$ 2,154	$ 777
Expenses									
Transportation and selling	**10**	37	–	**45**	50	11	**55**	87	11
Operating	**49**	5	7	**14**	8	5	**63**	13	12
Purchased product	**1,396**	862	366	**1,297**	1,169	373	**2,693**	2,031	739
Depreciation, depletion and amortization	**3**	6	1	**5**	6	–	**8**	12	1
	$ (16)	$ 21	$ 11	**$ –**	$ (10)	$ 3	**$ (16)**	$ 11	$ 14

(1) Excludes financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

EnCana's Marketing operations include marketing activities to optimize the value from the Company's proprietary production, the purchase of third party product primarily for the optimization of midstream assets and optimization of transportation commitments not fully utilized for the Company's own production. The increase in 2003 revenues reflects higher commodity prices experienced in the energy industry for the year. The increased revenue is comparatively offset by the change in product purchased. The change in Marketing's operating expense in 2003 is primarily due to the $20 million settlement related to the discontinued Merchant Energy operations, discussed in the Contractual Obligations and Contingencies section of this MD&A, and the inclusion of a full year of post Merger results.

Corporate

Corporate Items *($ millions)*		2003	2003 vs 2002		2002	2002 vs 2001		2001
Administration	$	**173**	**45%**	$	119	120%	$	54
Interest, net		**287**	**–1%**		290	753%		34
Foreign exchange (gain) loss		**(601)**	**4193%**		(14)	–217%		12
Income tax expense		**445**	**22%**		366	–13%		419

The increase in administrative expense in 2003 reflected the inclusion of the full year of post Merger operations, the effect of the change in the U.S./Canadian dollar exchange rate, higher governance costs and increased salary and consultant expenses. On a per unit basis, excluding discontinued operations volumes, administrative costs were $0.73 per barrel of oil equivalent for 2003 compared with $0.63 per barrel of oil equivalent for 2002 and $0.54 per barrel of oil equivalent for 2001.

Net interest expense remained relatively unchanged in 2003 compared to 2002. The higher net interest expense in 2002 over 2001 resulted primarily from the additional expense associated with the comparatively higher average debt level outstanding as a result of the Merger and redemption of capital securities.

The majority of the foreign exchange gain of $601 million resulted from the change in the U.S./Canadian dollar period end exchange rate applied to U.S. dollar denominated debt issued in Canada. Under Canadian GAAP, the Company is required to translate long-term debt borrowed in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

The effective tax rate for 2003 was 17 percent compared to 33 percent for 2002 and 33 percent for 2001. The decrease in the effective tax rate included the impact of a $359 million reduction in future income taxes resulting from the reductions in the Canadian federal and Alberta corporate income tax rates which were enacted in 2003 and related changes to the Canadian federal resource allowance deduction. The Canadian federal tax rate, which was reduced in other industries in 2000, is to be reduced by seven percentage points over the period 2003-2007 from 28 percent to 21 percent. In addition, the Canadian federal resource allowance deduction is to be phased out and replaced with a deduction for crown royalties paid over the same period. The Alberta tax rate was reduced by one half of one percentage point from 13 percent to 12.5 percent. The decrease also reflects the tax treatment of realized and unrealized Canadian capital gains of $581 million derived from a weakening of the U.S. dollar in relation to the Canadian dollar and the utilization of previously unrecognized capital losses. Income tax expense also reflects the translation of Canadian taxes denominated in Canadian dollars utilizing the increased average U.S./Canadian dollar exchange rate.

Current income tax expense was a recovery of $56 million for 2003, a recovery of $38 million for 2002, and an expense of $324 million for 2001. Current income tax expense was abnormally low in 2003 and 2002 in large part as a result of the merger with AEC, the subsequent business reorganization of the Company's business units at the end of 2002 and early 2003 and the amalgamation with AEC on January 1, 2003. The recovery relates principally to a shift of approximately $90 million of previously anticipated current income tax expense in 2003 to 2004.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

LIQUIDITY AND CAPITAL RESOURCES

Company expectations are that existing credit facilities and present and forecast capital resources will be sufficient to support its capital investment programs and future growth prospects in addition to enabling the Company to meet all other current and expected financial requirements. Fluctuations in commodity prices, product demand, foreign exchange rates, interest rates and various other risks may impact capital resources but have been partially mitigated through the risk management program detailed in Note 17 of the Consolidated Financial Statements and discussed in the Risk Management section of this MD&A.

EnCana's cash flow from continuing operations was $4,420 million in 2003 up $2,153 million, or 95 percent, compared with $2,267 million in 2002 and $1,463 million in 2001. The increase in cash flow from continuing operations was primarily the result of higher revenues from increases in commodity prices, inclusion of a full year of post Merger results and growth in sales volumes, partially offset by higher operating expenses.

EnCana's net debt, adjusted for working capital, was $5,931 million as at December 31, 2003 compared with $3,933 million at December 31, 2002 and $1,446 million at December 31, 2001. Working capital was $157 million at December 31, 2003, compared to $1,118 million at December 31, 2002. The 2002 working capital balance included $1,055 million related to the net assets and liabilities of Discontinued Operations. Cash flow together with proceeds from the dispositions of the Syncrude interest, Cold Lake and Express Pipeline Systems interests and other asset dispositions were used for the purchase of shares under the Company's Normal Course Issuer Bid, capital expenditures and acquisitions. The cash shortfall as a result of these activities and working capital changes increased net debt in 2003 by $1,998 million.

On October 2, 2003, the Company issued $500 million notes due in 10 years at 4.75 percent. The proceeds from this issue were used primarily to repay existing bank and commercial paper indebtedness.

Net debt to capitalization was 34 percent, up from 31 percent at December 31, 2002. Net debt to Earnings Before Interest, Taxes, Depreciation, Depletion and Amortization ("EBITDA") was 1.3 times the trailing 12-month cash flow at the end of the year. EBITDA is a measure that has no standardized meaning prescribed by Canadian GAAP and is considered a non-GAAP measure. Therefore, the measure may not be comparable to similar measures presented by other issuers. This measure is described and presented in this MD&A, in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and ability to generate funds to finance its operations. Management calculates net debt to EBITDA for credit analysts who use the measure to gauge a Company's ability to generate sufficient funds to cover its net debt.

As at December 31, 2003, the Company had available unused committed bank credit facilities in the amount of $1,575 million.

On December 31, 2003, the Company had $418 million of preferred securities recorded as long-term debt on its Consolidated Balance Sheet. Due to the adoption of the new Canadian accounting standard for liabilities and equity as discussed in the Accounting Policy Changes section of this MD&A these preferred securities were reclassified from equity to liabilities retroactively and, accordingly, all prior periods have been restated to reflect this change.

In October 2003, EnCana received approval from the Toronto Stock Exchange to purchase, for cancellation, common shares under a Normal Course Issuer Bid. Under the bid, EnCana is entitled to purchase for cancellation up to 23.2 million of its common shares over a 12-month period ending October 21, 2004. In 2003, combined purchases under the current bid and a previous bid were 23.8 million shares at an average price of C$49.65 per share. These purchases more than offset the approximately 5.5 million shares issued in 2003 as a result of the exercise of share purchase options. In 2004, EnCana has purchased for cancellation 2.5 million of its shares at an average price of C$54.52 per share under its current Normal Course Issuer Bid, approximately equal to share option exercises.

In February 2004, the Company announced its intention to redeem, on March 23, 2004, all of its Coupon Reset Subordinated Term Securities, Series A ("Term Securities") which have an aggregate principal amount of approximately C$126 million. The redemption price of the Term Securities is the principal amount plus accrued and unpaid interest to the redemption date. As at December 31, 2003, the Term Securities have been included as part of the Current Portion of Long-Term Debt in the Consolidated Financial Statements.

Goodwill

At December 31, 2003, the Company had $1,911 million in goodwill (2002 – $1,563 million) recorded on its Consolidated Balance Sheet as a result of the merger with AEC. As disclosed in Note 4 to the Consolidated Financial Statements, there were no transactions creating additional goodwill during 2003. The increase in goodwill results from the change in the year end rates to convert Canadian dollars to U.S. dollars.

CAPITAL EXPENDITURES

Capital Investment *($ millions)*	2003 (1)	2003 vs 2002	2002	2002 vs 2001	2001
Upstream					
Canada	**$ 3,198**	**130%**	$ 1,388	51%	$ 919
United States	**968**	**–18%**	1,176	746%	139
Ecuador	**265**	**58%**	168	–	–
United Kingdom	**223**	**172%**	82	78%	46
Other Countries	**78**	**–33%**	117	179%	42
Total Upstream	**$ 4,732**	**61%**	$ 2,931	156%	$ 1,146
Midstream & Marketing	**276**	**487%**	47	–51%	96
Corporate	**107**	**149%**	43	153%	17
Total	**$ 5,115**	**69%**	$ 3,021	140%	$ 1,259

(1) Includes acquisitions of $613 million but excludes dispositions on continuing operations of approximately $315 million.

The Company's consolidated capital expenditures increased 69 percent, or $2,094 million, compared to 2002 and 140 percent, or $1,762 million, when comparing 2002 over 2001. The majority of expenditures in both 2003 and 2002 were directed towards natural gas exploration and development in North America. The Company's capital investment was funded by cash flow in excess of amounts paid for purchases under the Normal Course Issuer Bid, proceeds received on the dispositions of the Syncrude interest and interests in the Cold Lake and Express Pipeline Systems as well as debt. Total cash proceeds received for dispositions, including the Syncrude interest and the Cold Lake and Express Pipeline Systems, amounted to $1,900 million compared to $423 million in 2002 and $134 million in 2001. Dispositions on continuing operations include the amount received for the 22.5 percent interest in the Llano oil discovery in the Gulf of Mexico which was exchanged for an additional 14 percent ownership in both the Scott and Telford fields of the U.K. central North Sea.

Upstream Capital Expenditures

Upstream capital expenditures in 2003 were higher by 61 percent, or $1,801 million, over 2002 and 156 percent, or $1,785 million, higher in 2002 over 2001. Increases in capital spending reflect the full twelve months of post Merger results in 2003 and nine months of post Merger results in 2002, increased operating activity, as well as the impact of the increase in the U.S./Canadian dollar exchange rate in 2003. The majority of 2003 expenditures related to North American properties, with spending in Canada directed primarily towards exploration and development of southern Alberta shallow gas projects as well as natural gas properties at Greater Sierra and Cutbank Ridge in northeast British Columbia. The higher Canadian capital expenditures over 2002 was the result of increased property acquisitions, inclusion of a full year of post Merger expenditures, the Cutbank Ridge land purchase and associated drilling, expansion of the Greater Sierra drilling program, acceleration of the 2004 capital program into 2003, and the effect of the change in the U.S./Canadian dollar exchange rate on Canadian denominated expenditures. Capital expenditures in the United States focused primarily on natural gas exploration and development at Jonah and Mamm Creek. Capital spending in the United States included $138 million in property acquisitions in 2003 compared to $656 million in 2002. Excluding property acquisitions, capital spending in the United States increased 60 percent to $830 million from $520 million as a result of increased drilling activity. Capital spending on international interests, excluding acquisitions, focused on production expansion in Ecuador and the U.K central North Sea as well as evaluating various other prospects in Africa, Australia, Brazil, Greenland and the Middle East. Also included is the purchase of an additional 14 percent ownership in both the Scott and Telford fields in the U.K. central North Sea in exchange for the 22.5 percent interest in the Llano oil discovery in the Gulf of Mexico and other minor property acquisitions. In addition to the Upstream capital expenditures in the table above are corporate acquisitions where the Company acquired additional interests in Ecuador for $116 million and acquired interests in developed and undeveloped reserves, landholdings and natural gas production in North Texas for $91 million.

U.K. – Buzzard Development In 2003, the Company received approval of the plan to develop the Buzzard oilfield located 53 kilometres off the coast of Scotland in the United Kingdom including approval of the environmental impact assessments. The Company's U.K. subsidiary is the operator of the project and holds a 43.2 percent interest. The field is expected to start production in late 2006 and reach a plateau by mid 2007 of 75,000 barrels per day of crude oil net to EnCana. As of December 31, 2003, the Company had invested approximately $90 million in the project and estimates future development costs to be an additional $770 million. The next phase of development in 2004 includes fabrication of the offshore platform and the start of pipeline installation.

Canadian East Coast In 2003, the Company, along with its partners, completed the drilling of five exploratory wells in the Canadian East Coast region. EnCana was the operator of three of these wells. Two of these exploration wells drilled near the Deep Panuke discovery (100 percent owned Margaree and 24.5 percent owned MarCoh) have increased the Company's confidence in the commercial potential of this discovery. During 2003, the Company withdrew the original development application for Deep Panuke filed in March 2002 with the National Energy Board and the Canada-Nova Scotia Offshore Petroleum Board. Further examination of the potential economic viability of the Deep Panuke project will be undertaken prior to the preparation of a revised development plan. As of December 31, 2003, the Company had invested approximately $340 (C$500) million on its Canadian East Coast assets including Deep Panuke. Until assessments of the economics are complete, the timing of any potential start of production and amount of additional costs which may be incurred are not determinable.

Western Canada – Cutbank Ridge During 2003, the Company completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in Cutbank Ridge, which is located in the foothills of British Columbia and Alberta. The Company purchased either 100 percent or a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 (C$369) million. The Company had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales. In 2003, the Company drilled 19 wells which produced 14 million cubic feet per day in December. As of December 31, 2003, the Company had invested approximately $360 (C$500) million on Cutbank Ridge and estimates 2004 spending to be approximately $125 (C$160) million. In 2004, the Company plans to drill 40 net natural gas wells at Cutbank Ridge.

Western Canadian Basin – Coalbed Methane In 2003, the Company expanded coalbed methane development on its 700,000 acres of 100 percent owned fee title lands in southern Alberta. During 2003, the Company drilled approximately 270 wells, increasing current production from the commercial demonstration project to 10 million cubic feet per day. As of December 31, 2003, the Company had invested approximately $60 (C$80) million on coalbed methane development in southern Alberta and estimates 2004 spending to be approximately $100 (C$130) million. Over the next 5 years, the Company expects to increase natural gas production from coal seams to more than 200 million cubic feet per day.

Gulf of Mexico The Company's operating partner completed drilling four appraisal wells in 2003 at the Tahiti oilfield which is located 304 kilometres southwest of New Orleans. As of December 31, 2003, the Company had invested approximately $301 million in the Gulf of Mexico including Tahiti. The Company holds a 25 percent interest in the Tahiti project. The next phase of development in 2004 includes the front end engineering and design of the project. Until completion of this phase and assessments of the economics are complete, the timing of any potential start of production and amount of additional costs which may be incurred are difficult to determine.

RESERVES

Proved Reserves by Country
Constant Prices After Royalties

As at December 31	Natural Gas			Crude Oil and NGLs (2)			Total (1)				
	2003	2002	2001	**2003**	2002	2001	**2003**	**2003 vs 2002**	2002	2002 vs 2001	2001
	(billions of cubic feet)			*(millions of barrels)*			*(millions of barrels of oil equivalent)*				
Canada	**5,256**	5,073	3,504	**629**	542	287	**1,505**	**8%**	1,388	59%	871
United States	**3,129**	2,573	236	**42**	41	20	**564**	**20%**	470	696%	59
Ecuador	**–**	–	–	**162**	156	–	**162**	**4%**	156	–	–
United Kingdom	**26**	20	7	**124**	97	21	**128**	**28%**	100	356%	22
Total	**8,411**	7,666	3,747	**957**	836	328	**2,359**	**12%**	2,114	122%	952

(1) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

(2) Includes condensate.

EnCana's policy is to retain independent qualified reserves evaluators to prepare reports on 100 percent of its oil and gas reserves. The reserves for both 2003 and 2002 were independently evaluated. The reserves for 2001 were internally evaluated. The Company has a Reserves Committee comprised entirely of independent directors which oversees the selection, qualifications and reporting procedures of the independent engineering consultants.

Proved Reserves Reconciliation by Country
Constant Prices After Royalties

As at December 31, 2003	Natural Gas					Crude Oil and Natural Gas Liquids (2)						
	Canada	USA	UK	Other	Total	Canada	USA	Ecuador	UK	Other	Total	Total
	(billions of cubic feet)					*(millions of barrels)*						*(MMBOE)* (1)
Start of year	5,073	2,573	20	–	7,666	542	41	156	97	–	836	2,114
Revisions and improved recovery	73	1	3	–	77	32	1	–	24	–	57	70
Extensions and discoveries	867	706	–	90	1,663	111	7	12	–	1	131	408
Acquisitions	9	152	8	–	169	1	1	17	7	–	26	55
Divestitures	(60)	(88)	–	(90)	(238)	–	(5)	(5)	–	(1)	(11)	(51)
Production	(706)	(215)	(5)	–	(926)	(57)	(3)	(18)	(4)	–	(82)	(237)
End of year	5,256	3,129	26	–	8,411	629	42	162	124	–	957	2,359

(1) MMBOE represents millions of barrels of oil equivalent. Natural gas is converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

(2) Includes condensate.

During 2003, the Company added approximately 482 million barrels of oil equivalent, or 203 percent of its production, to its proved reserves through drilling successes, acquisitions of selected properties and revisions net of property dispositions. EnCana's proved reserves as at December 31, 2003, on a constant price basis, after royalties, totalled 2,359 million barrels of oil equivalent representing a reserve life index of approximately 10 years based on 2003 production volumes.

Midstream & Marketing Capital Expenditures

Expenditures in 2003 related primarily to ongoing improvements to midstream facilities, the construction of the Countess gas storage facility and the expansion of the Wild Goose storage facility. Approximately $91 million was spent in 2003 on the Countess facility and $65 million on expansion of the Wild Goose facility. Capital spending also included approximately $53 million related to equipment operating lease buyouts.

The Company has completed gas injections into the first 10 billion cubic feet of new storage capacity at Countess. The second and third phases of the Countess storage facility are expected to take total capacity to about 40 billion cubic feet by the second quarter of 2005. As of November 2003, the expansion of the Wild Goose storage facility had increased withdrawal capability from 200 million cubic feet per day to 320 million cubic feet per day. By April 2004, withdrawal capacity is expected to be further increased to 480 million cubic feet per day while injection capacity is expected to rise from 80 million to 450 million cubic feet per day and total working gas inventory capacity will increase from 14 billion cubic feet to 24 billion cubic feet.

In early July, a subsidiary of the Company increased its equity interest in the OCP Pipeline in Ecuador from 31.4 percent to 36.3 percent. The OCP Pipeline completed performance testing in October 2003. As at December 31, 2003, OCP was shipping approximately 220,000 barrels per day and is expected to increase shipping volumes as field productivity increases in coming years. The shippers have ship or pay commitments of 350,000 barrels per day. The Company currently is transporting all of its Ecuadorian production through the OCP Pipeline. Prior to completion, the OCP asset was considered part of the Company's Midstream & Marketing division. Since the completion, the Company's equity interest in the OCP Pipeline has been transferred to the Upstream business segment and is included as part of the Ecuadorian region results.

Corporate Capital Expenditures

Corporate capital expenditures related primarily to spending on business information systems, the buyout of operating leases, leasehold improvements and furniture and office equipment. Expenditures in 2002 and 2001 related primarily to spending on business information systems.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. As at December 31, 2003, there were 460.6 million outstanding common shares compared to 478.9 million and 254.9 million at the end of 2002 and 2001 respectively. There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. These plans and their terms and outstanding balances are disclosed in detail in Note 15 to the Consolidated Financial Statements.

The Compensation Committee of the Board of Directors, in 2003, approved a long-term incentive strategy for employees throughout EnCana which includes a significantly reduced level of stock option grants to be supplemented by grants of Performance Share Units ("PSUs"). Beginning in 2004, it is the Company's intention that most stock options granted will have an associated Tandem Share Appreciation Right ("TSAR") and employees may elect to exercise either the stock option or the associated TSAR. PSUs and TSARs will result in cash payments by the Company and Common Shares will not be issued. These cash payments will be accounted for as expenses of the Company and equity dilution will not occur.

As previously detailed in the liquidity and capital section of this MD&A, the Company obtained regulatory approval under Canadian securities laws to purchase Common Shares under two consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 21, 2004. Under the terms of the bids, the Company repurchased for cancellation 23.8 million Common Shares during 2003, and as of December 31, 2003, was entitled to purchase for cancellation an additional 19.6 million Common Shares.

OFF BALANCE SHEET ARRANGEMENTS

LEASES

During 2003, the Company exercised buyout options and closed out a number of operating leases that were in place at the prior year end. These operating leases were on a variety of moveable field equipment, natural gas storage equipment and aircraft, which required periodic lease payments and were recorded as operating or administrative costs. The leases of the equipment and aircraft were financed by variable interest entities that were sponsored by various financial institutions. During 2003, the Company paid $262 million to close out these lease obligations by purchasing the related equipment which was included in the 2003 total capital spending figures discussed earlier in the MD&A.

As a normal course of business, the Company leases office space for personnel who support field operations and corporate purposes.

VARIABLE INTEREST ENTITIES

In December 2003, the Financial Accounting Standards Board ("FASB") in the United States issued Interpretation Number 46R "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51". The standard mandates that variable interest entities be consolidated by their primary beneficiary. The standard is effective the first reporting period ending after March 15, 2004 for all entities with the exception of special purpose entities as defined in prior accounting guidance. The standard is effective for the first period ending after December 15, 2003 for previously defined special purpose entities. In Canada, the Accounting Standards Board ("AcSB") has suspended the effective dates for Accounting Guideline AcG15, "Consolidation of Variable Interest Entities" in order to amend the guideline to harmonize with the corresponding U.S. guidance. The AcSB plans to issue an exposure draft in the immediate future with an effective period beginning on or after November 1, 2004.

At December 31, 2003, the Company did not have any variable interests in variable interest entities where the Company was the primary beneficiary.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. The following table summarizes the Company's contractual obligations at December 31, 2003:

Contractual Obligations (1)

	Expected Payment Date				
($ millions)	2004	2005 to 2006	2007 to 2008	2009+	Total
Long-Term Debt	$ 287	$ 221	$ 713	$ 3,257	$ 4,478
Asset Retirement Obligations	13	10	–	3,200	3,223
Operating Leases (2)	44	85	74	211	414
Pipeline Transportation	449	717	627	2,116	3,909
Capital Commitments	259	43	–	38	340
Purchase of Goods and Services	297	225	14	–	536
Product Purchases	142	79	49	157	427
Total Contractual Obligations	$ 1,491	$ 1,380	$ 1,477	$ 8,979	$ 13,327

(1) In addition, the Company has made commitments related to its risk management program. See Note 17 in the Consolidated Financial Statements. The Company also has an obligation to fund its Pension Plan as disclosed in Note 16 of the Consolidated Financial Statements.

(2) Related to office space and computer lease obligations.

In addition to the long-term debt payments outlined above, at December 31, 2003, the Company had $1,814 million outstanding related to Banker's Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company's long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the contractual obligations outlined above is included in Note 19 to the Consolidated Financial Statements.

As at December 31, 2003, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 69 million cubic feet per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 200 billion cubic feet at a weighted average price of $3.48 per thousand cubic feet. At December 31, 2003, these transactions had an unrealized loss of $108 million.

LEGAL PROCEEDINGS RELATED TO DISCONTINUED MERCHANT ENERGY OPERATIONS

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the Merger in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. Several of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

ACCOUNTING POLICIES AND ESTIMATES

CRITICAL ACCOUNTING POLICIES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired and was the result of the Merger with AEC, is assessed by the Company for impairment at least annually. Goodwill was allocated to the business segments at the time of the Merger based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

Oil and Gas Reserves

EnCana's proved oil and gas reserves are 100 percent evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

The Company enters into financial transactions to reduce its exposure to price fluctuations with respect to a portion of its oil and gas production to help achieve returns on new projects, targeted returns on new investments and steady funding of growth projects or to mitigate market price risk associated with cash flows expected to be generated from budgeted capital programs. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions. Realized gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related production occurs.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company's total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company also purchases foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Hedging Relationships

The Canadian Institute of Chartered Accountants ("CICA") modified Accounting Guideline 13 ("AcG 13") "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments" to require that all derivative instruments that do not qualify as a hedge under AcG 13, or are not designated as a hedge, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. In 2004, the Company has elected not to designate any of its current price risk management activities as accounting hedges under AcG13 and accordingly, will account for all derivatives using the mark-to-market accounting method. The impact on the Company's financial statements at January 1, 2004 is an increase in assets of $145 million, an increase in liabilities of $380 million and a deferred loss of $235 million which will be recognized as the contracts expire.

Pensions

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining services lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension costs are a component of compensation costs.

CHANGES IN ACCOUNTING PRINCIPLES AND PRACTICES

As at December 31, 2003, the Company has adopted the following changes in accounting principles and practices:

Change in the Company's Reporting Currency

The Company has adopted the U.S. dollar as its reporting currency as a result of its revenues being closely tied to the value of the U.S. dollar and to facilitate direct comparisons to most other North American upstream exploration and development companies. The change results in all self-sustaining financial results being translated from Canadian dollars to U.S. dollars using the current rate method, as described earlier under Accounting Guidelines in this MD&A, with exchange gains and losses reported as a separate component of shareholders' equity. Monetary assets and liabilities denominated in currencies, other than the applicable functional currency (as described in the Overview section of this MD&A), are translated at the year-end exchange rate with gains and losses recorded in the Consolidated Statement of Earnings.

Stock Based Compensation

The Company early adopted the fair value recognition for stock based compensation as required by the CICA accounting standard Handbook section 3870, "Stock-Based Compensation and Other Stock-Based Payments". This standard requires an option pricing model be used to determine the fair value of each option granted and the amount recognized over the vesting period of the option. Previously, the Company used the intrinsic value method to account for such compensation which resulted in no expense being recognized in the Company's financial results. As a result of early adopting, the Company can implement the new standard prospectively. The impact on the Company's 2003 net earnings has been disclosed in Note 2 of the Consolidated Financial Statements.

Asset Retirement Obligations

At December 31, 2003, the Company retroactively early adopted the Canadian accounting standard for accounting for asset retirement obligations as outlined in the CICA Handbook section 3110. The standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. The depreciation of the capitalized asset retirement cost will be determined on a basis consistent with depreciation, depletion and amortization. With the passage of time, accretion will increase the carrying amount of the asset retirement obligation. Previously the Company used the unit of production method to match estimated future retirement costs with the revenues generated from the producing assets. The impact of this change has been disclosed in Note 2 of the Consolidated Financial Statements.

Preferred Securities

The Company retroactively adopted the new Canadian accounting standard for liabilities and equity as outlined in the CICA Handbook section 3860, whereby the preferred securities issued by the Company are now recorded as a liability. All prior periods have been restated.

Full Cost Accounting

The Company early adopted Accounting Guideline AcG-16, "Oil and Gas Accounting-Full Cost". The new guideline has modified how the ceiling test is performed, which requires cost centres be tested for recoverability using undiscounted future cash flows which are determined by using forward indexed prices applied to proved reserves. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining expected cash flows. Additional disclosures are also required as provided in Note 11 of the Consolidated Financial Statements. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline other than additional required disclosure.

RISK MANAGEMENT

EnCana's results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The Company partially mitigates its exposure to market risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors.

The following table summarizes the unrecognized gains/(losses) on the Company's risk management activities discussed below.

	Contract Maturity			
As at December 31, 2003 ($ millions)	2004	2005	2006 and beyond	Total
Natural Gas	$ (29)	$ 38	$ 48	$ 57
Crude Oil	(275)	(4)	–	(279)
Gas Storage	(25)	–	–	(25)
Power	4	–	–	4
Foreign Currency	7	–	–	7
Interest Rates	22	14	8	44
Total	$ (296)	$ 48	$ 56	$ (192)

COMMODITY PRICES

As a means of mitigating exposure to commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts as disclosed in Note 17 of the Consolidated Financial Statements.

Derivative financial instruments are used by the Company to help manage its exposure to market risks related to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of market price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions. Gains or losses from these derivative financial instruments are recognized in oil and gas revenues in the period in which the related production occurs. Effective January 1, 2004, the Company adopted AcG 13 of the CICA and will use the mark-to-market accounting method as described earlier in this MD&A under Hedging Relationships.

NATURAL GAS

Produced Gas

The Company entered into swaps which fix the AECO and NYMEX prices and collars which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. AECO production area prices may be negatively impacted as large amounts of contracted capacity on pipelines moving gas to downstream markets come up for renewal over the next several years. As of December 31, 2003, the total unrecognized gain related to all significant natural gas risk management contracts was $40 million.

Purchased Gas

The Company has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. These contracts had an unrecognized gain of $17 million at December 31, 2003.

CRUDE OIL

Produced Crude Oil

The Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, costless collars and 3 way put spreads. As of December 31, 2003, the total unrecognized loss related to all significant crude oil risk management contracts was $279 million.

Purchased Crude Oil

As part of the crude oil marketing activities, the Company partially mitigated its exposure to the risk around crude oil inventory and third party margins through the use of futures and options. As at December 31, 2003, there was no gain or loss related to these contracts.

GAS STORAGE OPTIMIZATION

As part of its gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 9 months to manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps. As of December 31, 2003, the unrecognized loss related to these contracts was $25 million.

POWER PURCHASE ARRANGEMENTS

The Company has an electricity contract that expires in 2005. This contract was entered into as part of a cost management strategy. At December 31, 2003, this contract had an unrecognized gain of $4 million.

FOREIGN CURRENCY

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company has entered into foreign exchange contracts in the amount of $88 million at an average exchange rate of US$0.715 for the period to June 2004. The unrecognized loss with respect to these contracts was $7 million at December 31, 2003. The Company has also entered into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

INTEREST RATES

The Company has entered into various interest rate and cross currency interest rate swap transactions as a means of mitigating its exposure to the interest rates on debt instruments. The unrealized gain with respect to these transactions was $44 million at December 31, 2003.

CREDIT RISK

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board of Directors has approved a credit policy governing the Company's credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

OPERATIONAL, SAFETY AND ENVIRONMENTAL RISK

Operational risks are partially mitigated through a comprehensive insurance program designed to protect the Company from significant losses arising from the risk exposures.

Safety and environment risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

KYOTO PROTOCOL

The Kyoto Accord ("Accord") becomes effective once ratification from at least 55 Parties to the Convention representing 55 percent of Annex 1 Party emissions (developed countries) is obtained. Currently there is uncertainty surrounding whether or not the Accord will enter into force. The USA is notable in that it has rejected the protocol. Regardless, several states in the USA have begun initiatives to better manage greenhouse gas emissions. The initiatives in the USA are not expected have a material impact on EnCana's operations in the foreseeable future.

In December 2002, the Canadian Federal Government ratified the Accord committing Canada to reducing greenhouse gas emissions to 6 percent below 1990 levels over the period 2008 – 2012. It is premature to predict what impact the resulting potential regulations could have on the sector but it is possible that the Company would face minor increases in operating costs in order to comply with a greenhouse gas emissions reduction target. The federal government has also committed to several important principles that will continue to protect the competitiveness of the oil and gas industry beyond 2012, including a limit to the costs levied against excess emissions, a ten-year target lock-in period for new projects and additional flexibility mechanisms for achieving compliance.

ALBERTA ENERGY AND UTILITIES BOARD ("AEUB") RULING

The Company's 2003 production volumes, primarily from the Primrose Block in north eastern Alberta, were affected by an AEUB decision, in September, to shut-in natural gas production that put at risk the recovery of bitumen resources in the area. The decision resulted in EnCana's annualized natural gas production in the region to decline by approximately three million cubic feet per day. The future impact of this decision is not known at this time but is not expected to be material.

OUTLOOK

Outlook Volumes

	2004	2004 vs 2003 (2)	2003
Produced Gas *(million cubic feet per day)*	2,700 to 2,850	8%	2,566
Crude Oil and NGL's *(barrels per day)*	240,000 to 260,000	12%	222,544
Total *(barrels of oil equivalent per day)* (1)	690,000 to 735,000	10%	650,211

(1) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

(2) Percentage growth based on mid-point of guidance and excludes discontinued operations.

2004 Capital Investment

($ millions)

Upstream	$3,700 to $4,000
Midstream & Marketing and Corporate	$ 145
Core Capital	$3,845 to $4,145
Divestitures	$ (365)
Net Capital	$3,480 to $3,780

EnCana plans to continue to focus on growing natural gas production and storage capacity in North America and crude oil production in Canada, Ecuador and the U.K. central North Sea to deliver near term growth, with the Gulf of Mexico oil and Canadian East Coast gas growth platforms adding to longer term growth. The Company also plans to continue its efforts to expand its medium and long-term growth prospects through focussed international new ventures exploration.

Strong storage injection requirements combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2003. The outlook for 2004 and beyond will be principally impacted by weather, timing of new production and economic activity.

Volatility in crude oil prices is expected to continue in 2004 as a result of market uncertainties over the reintegration of Iraqi production, lower than expected inventory levels in the U.S., OPEC compliance with production quotas and the overall state of the world economies.

The Company expects its 2004 core capital investment program, of between $3,845 million and $4,145 million, to be funded from cash flow, proceeds from the divestitures of non-core assets and long-term debt.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates. The following tables provide projected estimates for 2004 of the sensitivity of the Company's 2004 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

Sensitivity of 2004 Net Earnings and Cash Flow (Including Hedges) (1) *($ millions)*	Net Earnings	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	75	75
$1.00 per barrel increase in the WTI oil price	10	10
$0.01 decrease in the U.S./Canadian dollar exchange rate	(20)	(5)

(1) Hedge position as at January 31, 2004.

Sensitivity of 2004 Net Earnings and Cash Flow (Excluding Hedges) *($ millions)*	Net Earnings	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	145	145
$1.00 per barrel increase in the WTI oil price	40	40
$0.01 decrease in the U.S./Canadian dollar exchange rate	(15)	1

These estimates are based on management's assumptions utilized for 2004 planning purposes, as discussed in this section. Assumptions include certain levels and profiles of capital expenditures, operating costs, projected sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other assumptions that impact operations. These assumptions can vary significantly from actual events and may result in material variances from the expected results.

In determining the current income tax expense deducted in arriving at these estimates, management has assumed a combined marginal tax rate of approximately 36 percent. This tax rate is itself affected in varying degrees by the assumptions referred to in the preceding paragraph. In addition, it has been assumed that marginal income in Canada will be taxed at marginal income tax rates, and that marginal income in the U.S.A. will be subject to Alternative Minimum Tax. Marginal rates in other jurisdictions are not expected to be material.

In November 2003, EnCana provided guidance for 2004 cash taxes in the range of $585 million to $730 million. Subsequently, in determining current income tax expense for 2003, approximately $90 million of current income tax was shifted to 2004 and, accordingly, the previous guidance has been increased by the same amount (i.e., revised guidance $675 million to $820 million). This guidance is also based on assumptions utilized for 2004 planning purposes, as discussed in this section, including natural gas prices based on NYMEX of approximately $4.90 per MMbtu, crude oil prices based on WTI of approximately $26.50 per barrel and a U.S. dollar to Canadian dollar exchange rate of $0.73.

February 6, 2004

EnCana Corporation

MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The financial statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgements. Financial information contained throughout the annual report is consistent with these financial statements.

The Company has developed and maintains an extensive system of internal controls that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls. The policy of the Company is to maintain the highest standard of ethics in all its activities and it has a written business conduct and ethics practice.

The Company's Board of Directors has approved the information contained in the financial statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange and the Toronto Stock Exchange. The Audit Committee meets at least on a quarterly basis.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit the Consolidated Financial Statements and provide an independent opinion.

Gwyn Morgan
President &
Chief Executive Officer

John D. Watson
Executive Vice-President &
Chief Financial Officer

February 6, 2004

AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENCANA CORPORATION

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2003 and December 31, 2002 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2003. These 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, 2003 and December 31, 2002 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 6, 2004

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 financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Our report to the shareholders dated February 6, 2004 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 financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 6, 2004

EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended December 31

($ millions, except per share amounts)		2003	2002	2001
			(restated – Note 2)	*(restated – Note 2)*
REVENUES, NET OF ROYALTIES	*(Note 4)*	$ 10,216	$ 6,276	$ 3,244
EXPENSES	*(Note 4)*			
Production and mineral taxes		189	119	77
Transportation and selling		545	364	111
Operating		1,297	813	448
Purchased product		3,455	2,200	739
Depreciation, depletion and amortization		2,222	1,304	510
Administrative		173	119	54
Interest, net	*(Note 7)*	287	290	34
Accretion of asset retirement obligation	*(Note 14)*	19	13	8
Foreign exchange (gain) loss	*(Note 8)*	(601)	(14)	12
Stock-based compensation	*(Note 2)*	18	–	–
Gain on corporate disposition	*(Note 6)*	–	(33)	–
		7,604	5,175	1,993
NET EARNINGS BEFORE INCOME TAX		2,612	1,101	1,251
Income tax expense	*(Note 9)*	445	366	419
NET EARNINGS FROM CONTINUING OPERATIONS		2,167	735	832
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 5)*	193	77	22
NET EARNINGS		$ 2,360	$ 812	$ 854
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 18)*			
Basic		$ 4.57	$ 1.76	$ 3.26
Diluted		$ 4.52	$ 1.74	$ 3.21
NET EARNINGS PER COMMON SHARE	*(Note 18)*			
Basic		$ 4.98	$ 1.94	$ 3.34
Diluted		$ 4.92	$ 1.92	$ 3.30

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the years ended December 31

($ millions)		2003	2002	2001
			(restated – Note 2)	*(restated – Note 2)*
RETAINED EARNINGS, BEGINNING OF YEAR				
As previously reported		$ 3,457	$ 2,787	$ 2,806
Retroactive adjustment for changes in accounting policies	*(Note 2)*	66	32	10
As restated		3,523	2,819	2,816
Net Earnings		2,360	812	854
Dividends on Common Shares	*(Note 18)*	(139)	(108)	(818)
Charges for Normal Course Issuer Bid	*(Note 15)*	(468)	–	–
Other	*(Note 18)*	–	–	(33)
RETAINED EARNINGS, END OF YEAR		$ 5,276	$ 3,523	$ 2,819

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

As at December 31

($ millions)		2003	2002 (restated – Note 2)
ASSETS			
Current Assets			
Cash and cash equivalents		$ 148	$ 116
Accounts receivable and accrued revenues		1,367	1,258
Inventories	(Note 10)	573	281
Assets of discontinued operations	(Note 5)	–	2,155
		2,088	3,810
Property, Plant and Equipment, net	(Notes 4, 11)	19,545	14,247
Investments and Other Assets	(Note 12)	566	292
Goodwill		1,911	1,563
	(Note 4)	$ 24,110	$ 19,912
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 1,579	$ 1,445
Income tax payable		65	13
Current portion of long-term debt	(Note 13)	287	134
Liabilities of discontinued operations	(Note 5)	–	1,100
		1,931	2,692
Long-Term Debt	(Note 13)	6,088	5,051
Other Liabilities		21	54
Asset Retirement Obligation	(Note 14)	430	309
Future Income Taxes	(Note 9)	4,362	3,088
		12,832	11,194
Shareholders' Equity			
Share capital	(Note 15)	5,305	5,511
Share options, net		55	84
Paid in surplus		18	51
Retained earnings		5,276	3,523
Foreign currency translation adjustment		624	(451)
		11,278	8,718
		$ 24,110	$ 19,912
Commitments and Contingencies	(Note 19)		

See accompanying notes to Consolidated Financial Statements.

Approved by the Board

David P. O'Brien
Director

Barry W. Harrison
Director

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31

($ millions)		2003	2002	2001
			(restated – Note 2)	*(restated – Note 2)*
OPERATING ACTIVITIES				
Net earnings from continuing operations		$ **2,167**	$ 735	$ 832
Depreciation, depletion and amortization		**2,222**	1,304	510
Future income taxes	*(Note 9)*	**501**	404	95
Unrealized foreign exchange (gain) loss	*(Note 8)*	**(545)**	(23)	35
Accretion of asset retirement obligation	*(Note 14)*	**19**	13	8
Other		**56**	(166)	(17)
Cash flow from continuing operations		**4,420**	2,267	1,463
Cash flow from discontinued operations		**39**	152	31
Cash flow		**4,459**	2,419	1,494
Net change in other assets and liabilities		**(84)**	(17)	(40)
Net change in non-cash working capital from continuing operations	*(Note 18)*	**(81)**	(853)	350
Net change in non-cash working capital from discontinued operations		**17**	64	(29)
		4,311	1,613	1,775
INVESTING ACTIVITIES				
Capital expenditures	*(Note 4)*	**(5,115)**	(3,021)	(1,259)
Proceeds on disposal of property, plant and equipment		**301**	363	31
Corporate (acquisitions) and dispositions	*(Note 6)*	**(193)**	60	56
Business combination with Alberta Energy Company Ltd.	*(Note 3)*	**–**	(80)	–
Equity investments		**(161)**	–	–
Net change in investments and other		**(63)**	43	19
Net change in non-cash working capital from continuing operations	*(Note 18)*	**(83)**	186	55
Discontinued operations		**1,585**	(146)	6
		(3,729)	(2,595)	(1,092)
FINANCING ACTIVITIES				
Issuance of short-term debt		**–**	–	281
Repayment of short-term debt		**–**	–	(439)
Issuance of long-term debt		**1,609**	1,506	990
Repayment of long-term debt		**(963)**	(1,206)	(256)
Issuance of common shares	*(Note 15)*	**114**	88	31
Purchase of common shares	*(Note 15)*	**(868)**	–	(4)
Dividends on common shares	*(Note 18)*	**(139)**	(108)	(818)
Other		**(13)**	(53)	–
Net change in non-cash working capital from continuing operations	*(Note 18)*	**2**	(7)	1
Discontinued operations		**(282)**	271	–
		(540)	491	(214)
DEDUCT: FOREIGN EXCHANGE LOSS (GAIN) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**10**	(2)	(5)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**32**	(489)	474
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**116**	605	131
CASH AND CASH EQUIVALENTS, END OF YEAR		$ **148**	$ 116	$ 605

Supplemental Cash Flow Information *(Note 18)*

See accompanying notes to Consolidated Financial Statements.

Prepared using Canadian generally accepted accounting principles.
All amounts in US$ millions, unless otherwise indicated.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2003

NOTE 1

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

The Company is in the business of exploration, production and marketing of natural gas, natural gas liquids and crude oil, as well as natural gas storage operations, natural gas liquids processing and power generation operations.

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which the Company does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgement regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of the Company's natural gas, natural gas liquids ("NGLs") and crude oil owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

Marketing revenues and purchased product are recorded on a gross basis as the Company takes title to product and has the risks and rewards of ownership. Revenues associated with the services provided where the Company acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when the title is transferred to the customer.

E) Employee Benefit Plans

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining services lives of employees covered by the plan.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

F) Income Taxes

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

G) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per common share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

H) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

I) Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

J) Property, Plant and Equipment

Upstream

The Company accounts for crude oil and natural gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs associated with the acquisition of, exploration for and the development of, natural gas and crude oil reserves, including asset retirement costs, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20% or greater in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and

ii. the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Midstream

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

K) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

L) Amortization of Other Assets

Amortization of deferred items included in Investments and Other Assets is provided for, where applicable, on a straight-line basis over the estimated useful lives of the assets.

M) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by the Company for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

N) Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method.

Amortization of asset retirement costs are included in depreciation, depletion and amortization on the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

O) Stock-based Compensation

The Company records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period (see Note 2).

Obligations for cash payments under the Company's share appreciation rights, deferred share units and performance share units are accrued as compensation expense over the vesting period. Fluctuations in the price of the Company's common shares will change the accrued compensation expense and are recognized when they occur.

P) Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transaction. This would include linking the particular derivative to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Company assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair values or cash flows of the hedged item.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions. Gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related production occurs.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company's total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may also enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company may also purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States and the related accounts receivable. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Q) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2003.

R) Recently Issued Accounting Pronouncements

During 2003, the following amended standard was issued:

Hedging Relationships

The Canadian Institute of Chartered Accountants ("CICA") modified Accounting Guideline 13 ("AcG – 13") "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments" to require that all derivative instruments that do not qualify as a hedge under AcG – 13, or are not designated as a hedge, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. For 2004, the Company has elected not to designate any of its current price risk management activities as accounting hedges under AcG – 13 and, accordingly, will account for all derivatives using the mark-to-market accounting method. The impact on the Company's financial statements at January 1, 2004, is an increase in assets of $145 million, an increase in liabilities of $380 million and a deferred loss of $235 million which will be recognized as the contracts expire ($162 million, net of tax).

NOTE 2

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

A) Reporting Currency

The Company has adopted the United States dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. The Company uses the current rate method for foreign currency translations. All prior periods have been restated to reflect the United States dollar as the reporting currency.

B) Preferred Securities

The Company has retroactively adopted the amendments made to CICA Handbook section 3860, "Financial Instruments – Disclosure and Presentation". As a result, the preferred securities issued by the Company are now recorded as a liability and included in long-term debt. The effect on the Company's Consolidated Statement of Earnings was to increase net earnings by $6 million (2002 – $2 million decrease; 2001 – $3 million decrease). The effect to the Company's Consolidated Balance Sheet is to increase current portion of long-term debt by $97 million, increase long-term debt by $321 million and decrease shareholders' equity by $418 million (2002 – $369 million increase to long-term debt; $289 million decrease to preferred securities of subsidiary; $80 million decrease to shareholders' equity).

C) Asset Retirement Obligations

The Company has retroactively early adopted the Canadian accounting standard outlined in CICA Handbook section 3110, "Asset Retirement Obligations". This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppel. The initial measurement of the asset retirement obligation is at fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization.

The Company previously estimated costs of dismantlement, removal, site reclamation and other similar activities and recorded them into earnings on a unit-of production basis over the remaining life of the proved reserves and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $36 million for the year ended December 31, 2003 (2002 – $34 million; 2001 – $22 million). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $142 million (2002 – $94 million), no change in the assets of discontinued operations (2002 – $11 million decrease), an increase in liabilities of $22 million (2002 – $16 million), an increase to retained earnings of $102 million (2002 – $66 million) and an increase in foreign currency translation adjustment of $18 million (2002 – $1 million).

D) Stock-based Compensation

The Company has early adopted the Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". As allowed by the section, this policy has been adopted prospectively, meaning all prior years have not been restated.

The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $18 million in 2003.

E) Full Cost Accounting

The Company has early adopted the new CICA Accounting Guideline AcG – 16, "Oil and Gas Accounting – Full Cost". The new guideline modifies how the ceiling test is performed, and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows (see Note 1). Additional disclosures are also required as provided in Note 11. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline AcG – 16.

F) Employee Future Benefits

The Company has early adopted the amendments made to disclosure requirements in the CICA Handbook section 3461, "Employee Future Benefits" (see Note 16). There is no impact on the Company's reported financial results as a result of applying these increased disclosure requirements.

G) Summary of Changes in Accounting Policies and Practices

The following table summarizes the effect of the changes in accounting policies:

As at and for the years ended December 31		2003 As Reported	2003 Change	2003 As Restated	2002 As Reported	2002 Change	2002 As Restated
Consolidated Balance Sheet							
Assets							
Assets of discontinued operations	*(C)*	$ –	$ –	$ –	$ 2,166	$ (11)	$ 2,155
Property, plant and equipment, net	*(C)*	19,403	142	19,545	14,153	94	14,247
Liabilities							
Liabilities of discontinued operations	*(C)*	$ –	$ –	$ –	$ 1,113	$ (13)	$ 1,100
Current portion of long-term debt	*(B)*	190	97	287	134	–	134
Long-term debt	*(B)*	5,767	321	6,088	4,682	369	5,051
Preferred securities of subsidiary	*(B)*	–	–	–	289	(289)	–
Other liabilities & asset retirement obligation	*(C)*	473	(22)	451	357	6	363
Future income taxes	*(C)*	4,318	44	4,362	3,065	23	3,088
Shareholders' Equity							
Preferred securities	*(B)*	$ 418	$ (418)	$ –	$ 80	$ (80)	$ –
Paid in surplus	*(D)*	–	18	18	51	–	51
Retained earnings	*(C)*	5,192	84	5,276	3,457	66	3,523
Foreign currency translation adjustment	*(C)*	606	18	624	(452)	1	(451)
Consolidated Statement of Earnings							
Net Earnings	*(B),(C),(D)*	$ 2,336	$ 24	$ 2,360	$ 780	$ 32	$ 812
Net Earnings per Common Share – Diluted	*(B),(C),(D)*	$ 4.88	$ 0.04	$ 4.92	$ 1.84	$ 0.08	$ 1.92

NOTE 3

BUSINESS COMBINATION WITH ALBERTA ENERGY COMPANY LTD.

On January 27, 2002, PanCanadian Energy Corporation ("PanCanadian") and Alberta Energy Company Ltd. ("AEC") announced plans to combine the companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the Business Corporations Act (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. The transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation.

This business combination has been accounted for using the purchase method with the results of operations of AEC included in the Consolidated Financial Statements from the date of acquisition.

The calculation of the purchase price and the allocation to assets and liabilities acquired as of April 5, 2002 is shown below:

Calculation of Purchase Price:		
Common Shares issued to AEC shareholders *(millions)*	218.5	
Price of Common Shares *(C$ per common share)*	38.43	
Value of Common Shares issued		$ 5,281
Fair value of AEC share options exchanged for share options of EnCana Corporation ("Share options")		105
Transaction Costs		94
Total purchase price		5,480
Plus: Fair value of liabilities assumed		
Current liabilities		1,120
Long-term debt (including preferred securities)		3,714
Other non-current liabilities		180
Future income taxes		1,665
Total Purchase Price and Liabilities Assumed		$ 12,159
Fair Value of Assets Acquired:		
Current assets		$ 946
Property, plant and equipment, net		8,897
Other non-current assets		381
Goodwill		1,935
Total Fair Value of Assets Acquired		$ 12,159
Goodwill Allocation:		
Upstream		$ 1,504
Midstream & Marketing		49
		1,553
Discontinued Operations		382
Total Goodwill Allocation		$ 1,935

NOTE 4

SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

- Upstream includes the Company's exploration for, and development and production of, natural gas, natural gas liquids and crude oil and other related activities. The majority of the Company's Upstream operations are located in Canada, the United States, the United Kingdom and Ecuador. International new venture exploration is mainly focused on opportunities in Africa, South America and the Middle East.
- Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product, and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company's own production.

Midstream & Marketing purchases all of the Company's North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

In 2003, the Company redefined its business segments to those described above. All prior periods have been restated to conform to the current presentation.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations *(for the years ended December 31)*

	Upstream			Midstream & Marketing		
	2003	2002	2001	**2003**	2002	2001
Revenues, Net of Royalties	**$ 6,327**	$ 3,674	$ 2,315	**$ 3,887**	$ 2,594	$ 931
Expenses						
Production and mineral taxes	**189**	119	77	**–**	–	–
Transportation and selling	**490**	277	100	**55**	87	11
Operating	**973**	626	294	**324**	187	154
Purchased product	**–**	–	–	**3,455**	2,200	739
Depreciation, depletion and amortization	**2,133**	1,233	478	**48**	36	10
Segment Income	**$ 2,542**	$ 1,419	$ 1,366	**$ 5**	$ 84	$ 17

	Corporate			Consolidated		
	2003	2002	2001	**2003**	2002	2001
Revenues, Net of Royalties	**$ 2**	$ 8	$ (2)	**$10,216**	$ 6,276	$ 3,244
Expenses						
Production and mineral taxes	**–**	–	–	**189**	119	77
Transportation and selling	**–**	–	–	**545**	364	111
Operating	**–**	–	–	**1,297**	813	448
Purchased product	**–**	–	–	**3,455**	2,200	739
Depreciation, depletion and amortization	**41**	35	22	**2,222**	1,304	510
Segment Income	**$ (39)**	$ (27)	$ (24)	**2,508**	1,476	1,359
Administrative				**173**	119	54
Interest, net				**287**	290	34
Accretion of asset retirement obligation				**19**	13	8
Foreign exchange (gain) loss				**(601)**	(14)	12
Stock-based compensation				**18**	–	–
Gain on corporate disposition				**–**	(33)	–
				(104)	375	108
Net Earnings Before Income Tax				**2,612**	1,101	1,251
Income tax expense				**445**	366	419
Net Earnings from Continuing Operations				**$ 2,167**	$ 735	$ 832

Geographic and Product Information *(for the years ended December 31)*

UPSTREAM	North America								
	Produced Gas and NGLs								
	Canada			United States			Crude Oil		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues, Net of Royalties	**$ 3,523**	$ 1,971	$ 1,598	**$ 1,143**	$ 454	$ 59	**$ 951**	$ 825	$ 523
Expenses									
Production and mineral taxes	**52**	50	48	**108**	35	7	**4**	20	22
Transportation and selling	**274**	151	72	**86**	59	–	**69**	35	16
Operating	**342**	255	112	**60**	35	11	**300**	201	153
Depreciation, depletion and amortization	**1,075**	625	261	**293**	202	31	**436**	237	124
Segment Income	**$ 1,780**	$ 890	$ 1,105	**$ 596**	$ 123	$ 10	**$ 142**	$ 332	$ 208

	Ecuador			U.K. North Sea			Other			Total Upstream		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues, Net of Royalties	**$ 412**	$ 245	$ –	**$ 118**	$ 103	$ 111	**$ 180**	$ 76	$ 24	**$ 6,327**	$ 3,674	$ 2,315
Expenses												
Production and mineral taxes	**25**	14	–	**–**	–	–	**–**	–	–	**189**	119	77
Transportation and selling	**45**	21	–	**16**	11	12	**–**	–	–	**490**	277	100
Operating	**83**	53	–	**18**	11	10	**170**	71	8	**973**	626	294
Depreciation, depletion and amortization	**159**	79	–	**74**	39	42	**96**	51	20	**2,133**	1,233	478
Segment Income	**$ 100**	$ 78	$ –	**$ 10**	$ 42	$ 47	**$ (86)**	$ (46)	$ (4)	**$ 2,542**	$ 1,419	$ 1,366

MIDSTREAM & MARKETING	Midstream			Marketing			Total Midstream & Marketing		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues	**$ 1,084**	$ 440	$ 154	**$ 2,803**	$ 2,154	$ 777	**$ 3,887**	$ 2,594	$ 931
Expenses									
Transportation and selling	**–**	–	–	**55**	87	11	**55**	87	11
Operating	**261**	174	142	**63**	13	12	**324**	187	154
Purchased product	**762**	169	–	**2,693**	2,031	739	**3,455**	2,200	739
Depreciation, depletion and amortization	**40**	24	9	**8**	12	1	**48**	36	10
Segment Income	**$ 21**	$ 73	$ 3	**$ (16)**	$ 11	$ 14	**$ 5**	$ 84	$ 17

Capital Expenditures

For the years ended December 31	2003	2002	2001
Upstream			
Canada	**$ 3,198**	$ 1,388	$ 919
United States	**968**	1,176	139
Ecuador	**265**	168	–
United Kingdom	**223**	82	46
Other Countries	**78**	117	42
	4,732	2,931	1,146
Midstream & Marketing	**276**	47	96
Corporate	**107**	43	17
Total	**$ 5,115**	$ 3,021	$ 1,259

Additions to Goodwill

There were no additions to goodwill during the year (see Note 3).

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
As at December 31	2003	2002	2003	2002
Upstream	**$ 18,532**	$ 13,656	**$ 21,742**	$ 16,042
Midstream & Marketing	**784**	470	**1,879**	1,403
Corporate	**229**	121	**489**	312
Assets of Discontinued Operations			**–**	2,155
Total	**$ 19,545**	$ 14,247	**$ 24,110**	$ 19,912

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,484 million (2002 – $1,333 million; 2001 – $785 million).

Major Customers

In connection with the marketing and sale of the Company's own and purchased natural gas and crude oil, for the year ended December 31, 2003, the Company had two customers which individually accounted for 10 percent of its consolidated revenues, net of royalties (2002 – none). One customer, a major international integrated energy company with a high quality investment grade credit rating, purchased approximately $1,362 million. The second customer, a Canadian natural gas clearing exchange with substantial credit controls, purchased approximately $1,056 million.

The majority of the Company's crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

The majority of the Company's revenues in the United Kingdom is earned from a single customer who has a high quality investment grade credit rating.

NOTE 5 DISCONTINUED OPERATIONS

2003

On February 28, 2003, the Company completed the sale of its 10 percent working interest in the Syncrude Joint Venture ("Syncrude") to Canadian Oil Sands Limited for net cash consideration of C$1,026 million ($690 million). On July 10, 2003 the Company completed the sale of the remaining 3.75 percent interest in Syncrude and a gross overriding royalty for net cash consideration of C$427 million ($309 million). This transaction completed the Company's disposition of its interest in Syncrude and, as a result, these operations have been accounted for as discontinued operations. There was no gain or loss on this sale.

2002

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations.

On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines operations for approximately C$1.6 billion ($1 billion) including the assumption of long-term debt by the purchaser. On January 2, 2003 and January 9, 2003, these sales were completed resulting in a gain on sale of C$263 million ($169 million).

For comparative purposes, the following tables present the effect of only the Merchant Energy discontinued operations on the Consolidated Financial Statements for the year ended December 31, 2001. The tables do not include any financial information related to Midstream – Pipelines or Upstream – Syncrude for 2001 as EnCana did not own these operations.

Consolidated Statement of Earnings

2003

UPSTREAM – SYNCRUDE *For the years ended December 31*	**2003**	2002
Revenues, Net of Royalties	$ **87**	$ 232
Expenses		
Transportation and selling	**2**	3
Operating	**46**	105
Depreciation, depletion and amortization	**7**	16
Interest, net	**–**	1
	55	125
Net Earnings Before Income Tax	**32**	107
Income tax expense	**8**	28
Net Earnings from Discontinued Operations	$ **24**	$ 79

2002

MIDSTREAM & MARKETING	Merchant Energy			Midstream – Pipelines			Total		
For the years ended December 31	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenues	$ **–**	$ 922	$ 2,646*	$ **–**	$ 135	$ –	$ **–**	$ 1,057	$ 2,646
Expenses									
Operating	**–**	–	–	**–**	50	–	**–**	50	–
Purchased product	**–**	931	2,578*	**–**	–	–	**–**	931	2,578
Depreciation, depletion and amortization	**–**	–	4	**–**	18	–	**–**	18	4
Administrative	**–**	22	27	**–**	–	–	**–**	22	27
Interest, net	**–**	–	–	**–**	19	–	**–**	19	–
Foreign exchange (gain)	**–**	–	–	**–**	(3)	–	**–**	(3)	–
(Gain) loss on discontinuance	**–**	19	–	**(220)**	–	–	**(220)**	19	–
	–	972	2,609	**(220)**	84	–	**(220)**	1,056	2,609
Net Earnings (Loss) Before Income Tax	**–**	(50)	37	**220**	51	–	**220**	1	37
Income tax expense (recovery)	**–**	(17)	15	**51**	20	–	**51**	3	15
Net Earnings (Loss) from Discontinued Operations	$ **–**	$ (33)	$ 22	$ **169**	$ 31	$ –	$ **169**	$ (2)	$ 22

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as revenues and expenses – purchased product. The amendment had no effect on net earnings or cash flow but revenues and expenses – purchased product have been reduced by $727 million.

Consolidated Total

For the years ended December 31	**2003**	2002	2001
Revenues, Net of Royalties	**$ 87**	$ 1,289	$ 2,646
Expenses			
Transportation and selling	**2**	3	–
Operating	**46**	155	–
Purchased product	**–**	931	2,578
Depreciation, depletion and amortization	**7**	34	4
Administrative	**–**	22	27
Interest, net	**–**	20	–
Foreign exchange (gain)	**–**	(3)	–
(Gain) loss on discontinuance	**(220)**	19	–
	(165)	1,181	2,609
Net Earnings Before Income Tax	**252**	108	37
Income tax expense	**59**	31	15
Net Earnings from Discontinued Operations	**$ 193**	$ 77	$ 22

Consolidated Balance Sheet

As all discontinued operations have either been disposed of or wind up has been completed, there are no remaining assets or liabilities at December 31, 2003. The balance sheet below shows the assets and liabilities of these operations as at December 31, 2002.

As at December 31, 2002	Syncrude	Merchant Energy	Midstream – Pipelines	Total
Assets				
Cash and cash equivalents	$ 18	$ –	$ 43	$ 61
Accounts receivable and accrued revenues	41	–	20	61
Inventories	9	–	1	10
	68	–	64	132
Property, plant and equipment, net	884	–	517	1,401
Investments and other assets	–	–	237	237
Goodwill	264	–	121	385
	1,216	–	939	2,155
Liabilities				
Accounts payable and accrued liabilities	68	3	25	96
Income tax payable	(4)	–	11	7
Short-term debt	277	–	–	277
Current portion of long-term debt	–	–	15	15
	341	3	51	395
Long-term debt	–	–	365	365
Future income taxes	236	–	104	340
	577	3	520	1,100
Net Assets of Discontinued Operations	$ 639	$ (3)	$ 419	$ 1,055

NOTE 6

CORPORATE (ACQUISITIONS) AND DISPOSITIONS

For the years ended December 31	**2003**	2002	2001
Acquisitions			
Vintage	**$ (116)**	$ –	$ –
Savannah	**(91)**	–	–
Other	**–**	–	(47)
	(207)	–	(47)
Dispositions			
EnCana Suffield Gas Pipeline Inc.	**–**	60	–
Other	**14**	–	103
	14	60	103
	$ (193)	$ 60	$ 56

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $116 million. On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $91 million. Savannah's operations are in Texas, U.S.A.

These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates of acquisition. These acquisitions were accounted for as follows:

	Vintage	Savannah
Working Capital	$ 1	$ 1
Property, Plant and Equipment	126	110
Future Income Taxes	(11)	(20)
	$ 116	$ 91

In 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $60 million, with a gain on sale of $33 million.

NOTE 7

INTEREST, NET

For the years ended December 31	**2003**	2002	2001
Interest Expense – Long-Term Debt	**$ 281**	$ 252	$ 55
Early Retirement of Long-Term Debt	**–**	34	–
Interest Expense – Other	**20**	10	–
Interest Income	**(14)**	(6)	(21)
	$ 287	$ 290	$ 34

The Company has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2003 by $23 million (2002 – $20 million; 2001 – $11 million).

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
8.40% due December 15, 2004				
C$100 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 41 basis points
8.75% due November 9, 2005				
C$200 million	US$73 million	C$ Fixed	US$ Fixed*	4.99%
	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 4 basis points
7.50% due August 25, 2006				
C$100 million	US$73 million	C$ Fixed	US$ Fixed*	4.14%
5.80% due June 2, 2008				
C$225 million	US$71 million	C$ Fixed	US$ Fixed*	4.80%
	C$125 million	C$ Fixed	C$ Floating	3 month Bankers' Acceptance less 5 basis points
7.00% due March 23, 2034				
C$126 million	C$126 million	C$ Fixed	C$ Floating	3 month Bankers' Acceptance plus 104 basis points

* These instruments have been subject to multiple swap transactions.

NOTE 8

FOREIGN EXCHANGE (GAIN) LOSS

For the years ended December 31	2003	2002	2001
Unrealized Foreign Exchange (Gain) Loss on Translation			
of U.S. Dollar Debt Issued in Canada	$ (545)	$ (23)	$ 35
Other Foreign Exchange (Gains) Losses	(56)	9	(23)
	$ (601)	$ (14)	$ 12

NOTE 9

INCOME TAXES

For the years ended December 31	2003	2002	2001
Provision for Income Taxes			
Current			
Canada	$ (136)	$ (26)	$ 320
United States	39	(31)	1
Ecuador	39	17	–
Other	2	2	3
	(56)	(38)	324
Future	860	424	148
Future tax rate reductions	(359)	(20)	(53)
	$ 445	$ 366	$ 419

The net future income tax liability is comprised of:

As at December 31	2003	2002
Future Tax Liabilities		
Capital assets in excess of tax values	$ 3,515	$ 2,821
Timing of Partnership items	1,162	513
Future Tax Assets		
Net operating losses carried forward	(174)	(203)
Other	(141)	(43)
Net Future Income Tax Liability	$ 4,362	$ 3,088

The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

For the years ended December 31	2003	2002	2001
Net Earnings Before Income Tax	$ 2,612	$ 1,101	$ 1,251
Canadian Statutory Rate	40.95%	42.3%	42.8%
Expected Income Taxes	1,070	467	536
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	231	147	74
Canadian resource allowance	(258)	(200)	(167)
Large corporations tax	27	23	9
Statutory rate differences	(50)	(36)	(12)
Effect of tax rate changes	(359)	(20)	(53)
Non-taxable capital gains	(119)	(9)	–
Previously unrecognized capital losses	(119)	–	–
Other	22	(6)	32
	$ 445	$ 366	$ 419
Effective Tax Rate	17.0%	33.2%	33.5%

The approximate amounts of tax pools available are as follows:

As at December 31	2003	2002
Canada	$ 6,904	$ 4,444
United States	2,112	2,175
Ecuador	1,015	831
United Kingdom	230	123
	$ 10,261	$ 7,573

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a later year end than the Company.

NOTE 10

INVENTORIES

As at December 31	2003	2002
Product		
Upstream	$ 11	$ 34
Midstream & Marketing	546	239
Parts and Supplies	16	8
	$ 573	$ 281

NOTE 11

PROPERTY, PLANT AND EQUIPMENT, NET

	2003			2002		
As at December 31	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream						
Canada	$ 20,607	$ (7,500)	$ 13,107	$ 14,077	$ (4,770)	$ 9,307
United States	4,062	(523)	3,539	3,184	(262)	2,922
Ecuador	1,442	(188)	1,254	1,060	(73)	987
United Kingdom	752	(231)	521	448	(135)	313
Other Countries	316	(205)	111	225	(98)	127
Total Upstream	27,179	(8,647)	18,532	18,994	(5,338)	13,656
Midstream & Marketing	915	(131)	784	541	(71)	470
Corporate	320	(91)	229	191	(70)	121
	$ 28,414	$ (8,869)	$ 19,545	$ 19,726	$ (5,479)	$ 14,247

* Depreciation, depletion and amortization

Included in Midstream is $97 million (2002 – $47 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Included in the property, plant and equipment cost are asset retirement costs of $245 million (2002 – $175 million). Administrative costs have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects excluded from depletable costs were:

For the years ended December 31	2003	2002	2001
Canada	$ 1,035	$ 562	$ 257
United States	604	282	116
Ecuador	89	–	–
United Kingdom	175	112	–
Other Countries	111	127	88
	$ 2,014	$ 1,083	$ 461

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. At December 31, 2003, the Company completed its impairment review of pre-production cost centres and determined that $85 million of costs should be charged to the Consolidated Statement of Earnings (2002 – $ nil).

The prices used in the ceiling test evaluation of the Company's natural gas, crude oil and natural gas liquids reserves at December 31, 2003 were:

	2004	2005	2006	2007	2008	% decrease to 2015
Natural Gas *($/mcf)*						
Canada	$ 4.05	$ 3.87	$ 3.28	$ 3.37	$ 3.69	0.4%
United States	4.40	4.18	3.41	3.51	3.95	0.4%
United Kingdom	1.76	1.57	1.44	1.44	1.44	–
Crude Oil *($/barrel)*						
Canada	$ 17.41	$ 16.03	$ 14.42	$ 13.86	$ 13.67	1.6%
Ecuador	18.26	16.18	14.28	14.35	14.36	–
United Kingdom	26.82	24.88	21.01	20.44	20.41	0.1%
Natural Gas Liquids *($/barrel)*						
Canada	$ 23.25	$ 21.40	$ 19.10	$ 19.09	$ 19.20	0.4%
United States	23.62	21.84	19.91	19.53	19.36	0.2%
United Kingdom	20.05	18.57	16.83	16.71	16.67	0.2%

NOTE 12 INVESTMENTS AND OTHER ASSETS

As at December 31	**2003**	2002
Equity Investments	**$ 217**	$ 62
Value Added Tax Recoverable	**112**	56
Marketing Contracts	**22**	27
Deferred Financing Costs	**31**	28
Deferred Pension Costs	**53**	15
Other	**131**	104
	$ 566	$ 292

Equity Investments

Included in Equity Investments is the following:

i. Included in Midstream & Marketing is a 36% indirect equity investment in Oleoducto Transandino ("OTA"), which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile.

ii. Included in Upstream – Ecuador is a 36% indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. ("OCP"), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to a new export marine terminal.

The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs.

NOTE 13

LONG-TERM DEBT

As at December 31	Note	2003	2002
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*B*	$ 1,425	$ 879
Unsecured notes and debentures	*C*	1,335	1,155
Preferred securities	*D*	252	206
		3,012	2,240
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	*E*	417	441
U.S. unsecured notes and debentures	*F*	2,713	2,284
Preferred securities	*D*	150	150
		3,280	2,875
Increase in Value of Debt Acquired	*G*	83	70
Current Portion of Long-Term Debt	*H*	(287)	(134)
		$ 6,088	$ 5,051

A) Overview

Revolving credit and term loan borrowings

At December 31, 2003, the Company had in place a revolving credit and term loan facility for $4 billion Canadian dollars or its equivalent amount in U.S. dollars (US$3 billion). The facility consists of two tranches of C$2 billion (US$1.5 billion) each. One tranche is fully revolving for a 364-day period with provision for annual extensions at the option of the lenders and upon notice from the Company. If not extended, this tranche converts to a non-revolving reducing loan for a term of one year. The second tranche is fully revolving for a period of three years from the date of the agreement, December 2002. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from the Company. The facility is unsecured and bears interest at either the lenders' rates for Canadian prime commercial loans, U.S. base rate loans, Bankers' Acceptances rates, or at LIBOR plus applicable margins.

At December 31, 2003, a subsidiary of the Company had in place a credit facility totalling $300 million (C$388 million). The facility is guaranteed by EnCana Corporation and fully revolving for three years from the date of the Agreement, December 2003. The facility is extendable annually for an additional one year period at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders' U.S. base rate or at LIBOR plus applicable margins.

One of the Company's partnerships has a credit agreement, consisting of a term loan facility, senior secured notes and a levelization account, relating to the construction of a cogeneration plant. The term loan bears interest at the prevailing prime lending rate plus 0.25%. The notes bear interest at the prevailing prime lending rate plus 1.25%. The partnership also has an option under the credit agreement to use an average Bankers' Acceptance rate plus a margin that will vary during the term. The levelization account accumulates interest at the yield rate of the most recent Government of Canada bond issue with a 20-year maturity as of January 20th each year. The term loan and senior notes are secured by the project facilities.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper of $1,749 million (2002 – $871 million) maturing at various dates with a weighted average interest rate of 2.55% and LIBOR loans of $65 million (C$84 million) with a weighted average interest rate of 1.69%. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2003 relating to revolving credit and term loan agreements were approximately $3 million (2002 – $3 million).

Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company's current medium term note program was renewed in 2003 with C$1 billion ($774 million) unutilized at December 31, 2003. The notes may be denominated in Canadian dollars or in foreign currencies.

The Company has in place a shelf prospectus for U.S. Unsecured Notes in the amount of US$2.0 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. At December 31, 2003, US$1.5 billion remains unutilized.

B) Canadian revolving credit and term loan borrowings

	C$ Principal Amount	2003	2002
Bankers' Acceptances	$ 773	$ 598	$ 276
Commercial Paper	1,033	799	580
Cogeneration Facility, matures March 31, 2016	36	28	23
	$ 1,842	$ 1,425	$ 879

C) Canadian unsecured notes and debentures

	C$ Principal Amount	2003	2002
8.15% due July 31, 2003	$ –	$ –	$ 63
6.60% due on June 30, 2004	50	39	32
7.00% due December 1, 2004	100	77	63
5.95% due October 1, 2007	200	155	127
5.30% due December 3, 2007	300	232	189
5.95% due June 2, 2008	100	77	63
5.80% due June 2, 2008	125	97	79
5.80% due June 19, 2008	100	77	63
6.10% due June 1, 2009	150	116	95
7.15% due December 17, 2009	150	116	95
8.50% due March 15, 2011	50	39	32
7.10% due October 11, 2011	200	155	127
7.30% due September 2, 2014	150	116	95
5.50% / 6.20% due June 23, 2028	50	39	32
	$ 1,725	$ 1,335	$ 1,155

D) Preferred securities

	C$ Principal Amount	2003	2002
Canadian Dollar			
7.00% due on March 23, 2034	$ 126	$ 97	$ 80
8.50% due September 30, 2048	200	155	126
	$ 326	252	206
U.S. Dollar			
9.50% due September 30, 2048		150	150
		$ 402	$ 356

The preferred securities are unsecured junior subordinated debentures. Subject to certain conditions, the Company has the right to defer payments of interest on the securities for up to 20 consecutive quarterly periods. The Company may satisfy its obligation to pay deferred interest or the principal amount by delivering sufficient equity securities to the Trustee.

On March 23, 1999, the Company issued C$126 million of Coupon Reset Subordinated Term Securities – Series A due March 23, 2034. Interest is payable semi-annually at a rate of 7% per annum for the first five years and is reset at the Five Year Government of Canada Yield plus 2% on each fifth anniversary of the date of issuance. The securities are redeemable by the Company, in whole or in part, at any time on or after March 23, 2004, at par plus accrued and unpaid interest. With respect to these securities, the Company entered a series of option transactions that result in an effective floating interest rate equal to three-month Bankers' Acceptance rate plus 104 basis points on C$126 million. On February 4, 2004, the Company announced its intention to repurchase these securities on March 23, 2004.

The 8.50% and the 9.50% preferred securities were acquired in the business combination with AEC. Interest on these securities is paid quarterly. These securities are redeemable by the Company, in whole or in part, at any time on or after August 9, 2004 and September 30, 2004 respectively at par plus accrued and unpaid interest.

E) U.S. revolving credit and term loan borrowings

	2003	2002
Commercial Paper	$ 352	$ 16
LIBOR Loan	65	425
	$ 417	$ 441

F) U.S. unsecured notes and debentures

	C$ Amount	2003	2002
Floating Rate			
5.50% due on March 17, 2003		$ –	$ 71
8.40% due December 15, 2004	94*	73	73
8.75% due November 9, 2005	94*	73	73
Fixed Rate			
8.75% due November 9, 2005	94*	73	73
7.50% due August 25, 2006	94*	73	73
5.80% due June 2, 2008	92*	71	71
7.65% due September 15, 2010		200	200
6.30% due November 1, 2011		500	500
4.75% due October 15, 2013		500	–
8.125% due September 15, 2030		300	300
7.20% due November 1, 2031		350	350
7.375% due November 1, 2031		500	500
		$ 2,713	$ 2,284

* The Company has entered into a series of cross-currency and interest rate swap transactions that effectively convert these Canadian dollar denominated notes to U.S. dollars. The effective U.S. dollar principal is shown in the table.

G) Increase in value of debt acquired

Certain of the notes and debentures of the Company were acquired in the business combination described in Note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 28 years.

H) Current portion of long-term debt

	2003	2002
5.50% Medium Term Note due March 17, 2003	$ –	$ 71
8.15% Debenture due July 31, 2003	–	63
7.00% Coupon Reset Subordinated Term Securities due March 23, 2034	97	–
6.60% Medium Term Note due June 30, 2004	39	–
7.00% Medium Term Note due December 1, 2004	77	–
8.40% Medium Term Note due December 15, 2004	73	–
Cogeneration Facility	1	–
	$ 287	$ 134

I) Mandatory debt payments

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2004	$ 278	$ 73	$ 287
2005	2	146	147
2006	2	73	74
2007	503	–	389
2008	328	71	324
Thereafter	2,780	2,917	5,071
Total	$ 3,893	$ 3,280	$ 6,292

The amount due in 2004 excludes Bankers' Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

NOTE 14 ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties.

As at December 31	2003	2002
Asset Retirement Obligation, Beginning of Year	**$ 309**	$ 163
Liabilities Incurred	**64**	146
Liabilities Settled	**(23)**	(13)
Accretion Expense	**19**	13
Other	**61**	–
Asset Retirement Obligation, End of Year	**$ 430**	$ 309

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,223 million (2002 – $2,516 million), which has been discounted using a credit-adjusted risk free rate of 5.9 percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at the time of removal.

NOTE 15 SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

	2003		2002	
As at December 31	**Number *(millions)***	**Amount**	Number *(millions)*	Amount
Common Shares Outstanding, Beginning of Year	**478.9**	**$ 5,511**	254.9	$ 142
Shares Issued to AEC Shareholders *(Note 3)*	**–**	**–**	218.5	5,281
Shares Issued under Option Plans	**5.5**	**114**	5.5	88
Shares Repurchased	**(23.8)**	**(320)**	–	–
Common Shares Outstanding, End of Year	**460.6**	**$ 5,305**	478.9	$ 5,511

Normal Course Issuer Bid

Effective October 16, 2002, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid. Under the bid, the Company could purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. On October 20, 2003, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 22, 2003. Under this bid, the Company may purchase for cancellation up to 23,212,341 of its Common Shares, representing five percent of the 464,246,813 Common Shares outstanding as of October 14, 2003. The current Normal Course Issuer Bid expires on October 21, 2004.

In 2003, the Company purchased, for cancellation, 23,839,400 Common Shares for total consideration of $868 million. Of the $868 million paid, $320 million was charged to share capital, $80 million was charged to paid in surplus and $468 million was charged to retained earnings.

Stock Options

The Company has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous successor and/or related company replacement plans expire 10 years from the date the options were granted.

In conjunction with the business combination transaction described in Note 3, options to purchase AEC common shares were replaced with options to purchase Common Shares of EnCana ("AEC replacement plan") in a manner consistent with the provisions of the AEC stock option plan. Options granted under the AEC plan prior to April 21, 1999 expire after seven years and options granted after April 20, 1999 expire after five years. The business combination resulted in these replacement options, along with all options outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase Common Shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. It is the Company's intent that all options issued in 2004 will have an associated Tandem Share Appreciation Right ("TSAR") attached to them.

Canadian Pacific Limited Replacement Plan

As part of the Canadian Pacific Limited ("CPL") reorganization, as described in Note 18, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

Directors' Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase Common Shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued.

The following tables summarize the information about options to purchase Common Shares:

	2003		2002	
As at December 31	**Stock Options** *(millions)*	**Weighted Average Exercise Price** *(C$)*	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*
Outstanding, Beginning of Year	**29.6**	**39.74**	10.5	32.31
Granted under EnCana Plan	**6.3**	**47.98**	12.1	48.13
Granted under AEC Replacement Plan	**–**	**–**	13.1	32.01
Granted under Directors' Plan	**0.1**	**47.87**	0.1	48.04
Exercised	**(5.5)**	**29.11**	(5.5)	25.20
Forfeited	**(1.7)**	**41.18**	(0.7)	43.81
Outstanding, End of Year	**28.8**	**43.13**	29.6	39.74
Exercisable, End of Year	**15.6**	**38.92**	17.7	34.10

	Outstanding Options			Exercisable Options	
As at December 31 Range of Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
13.50 to 19.99	1.5	0.9	18.86	1.5	18.86
20.00 to 24.99	1.3	1.5	22.38	1.3	22.38
25.00 to 29.99	2.2	1.5	26.49	2.2	26.49
30.00 to 43.99	1.3	2.2	38.89	1.2	38.52
44.00 to 53.00	22.5	3.7	47.93	9.4	47.63
	28.8	2.8	43.13	15.6	38.92

At December 31, 2003, there were 7.9 million Common Shares reserved for issuance under stock option plans (2002 – 12.8 million).

As described in Note 2, the Company recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share in 2003 would have been $2,326 million; $4.91 per common share – basic; $4.85 per common share – diluted (2002 – $761 million; $1.82 per common share – basic; $1.80 per common share – diluted).

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

For the years ended December 31	2003	2002
Weighted Average Fair Value of Options Granted *(C$)*	$ 12.21	$ 13.31
Risk-free Interest Rate	3.87%	4.29%
Expected Lives *(years)*	3.00	3.00
Expected Volatility	0.33	0.35
Annual Dividend per Share *(C$/common share)*	$ 0.40	$ 0.40

NOTE 16

COMPENSATION PLANS

A) Pensions

The most recent actuarial evaluation completed for the Company is dated December 31, 2003.

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits to substantially all of its employees.

For the years ended December 31	2003	2002	2001
Total expense for defined contribution plans	$ 12	$ 9	$ 6

Information about defined benefit post-retirement benefit plans, in aggregate, is as follows:

As at December 31	2003	2002
Accrued Benefit Obligation, Beginning of Year	$ 167	$ 85
Plan acquisition	–	55
Current service cost	6	3
Interest cost	12	8
Benefits paid	(11)	(5)
Actuarial loss	13	10
Contributions	1	–
Special termination benefits	–	2
Changes as a result of curtailment	–	1
Plan amendments	1	8
Foreign exchange	39	–
Accrued Benefit Obligation, End of Year	$ 228	$ 167

As at December 31	2003	2002
Fair Value of Plan Assets, Beginning of Year	$ 117	$ 84
Plan acquisition	–	53
Transfers to defined contribution plan	–	(6)
Actual return on plan assets	14	(10)
Employer contributions	51	1
Employees' contributions	1	–
Benefits paid	(11)	(5)
Foreign exchange	31	–
Fair Value of Plan Assets, End of Year	$ 203	$ 117

As at December 31	2003	2002
Funded Status – Plan Assets less than Benefit Obligation	$ (25)	$ (50)
Amounts Not Recognized		
Unamortized Net Actuarial Loss	66	51
Unamortized Past Service Cost	13	10
Net Transitional Asset	(9)	(9)
Accrued Benefit Asset	$ 45	$ 2

As at December 31	2003	2002
Prepaid Benefit Cost	$ 53	$ 15
Accrued Benefit Cost	(8)	(13)
Net Amount Recognized	$ 45	$ 2

Included in the above accrued benefit obligation and fair value of plan assets at year-end for EnCana Corporation are unfunded benefit obligations of $14 million related to the Company's other post retirement benefit plan. At the end of 2002, the Company had unfunded obligations of $34 million related to three of the Company's defined benefit pension plans and the other post retirement benefit plans.

The weighted average assumptions used to determine benefit obligations are as follows:

As at December 31	2003	2002
Discount Rate	6.0%	6.5%
Rate of Compensation Increase	4.75%	3.5%

The weighted average assumptions used to determine periodic expense are as follows:

For the years ended December 31	2003	2002
Discount Rate	6.5%	6.5%
Expected Long-term Rate of Return on Plan Assets		
Registered pension plans	6.75%	7.0%
Supplemental pension plans	3.375%	3.5%
Rate of Compensation Increase	4.75%	3.5%

The periodic expense for benefits is as follows:

For the years ended December 31	2003	2002	2001
Current Service Cost	$ 6	$ 3	$ 2
Interest Cost	12	8	5
Expected Return on Plan Assets	(9)	(8)	(6)
Amortization of Net Actuarial Loss	4	1	–
Amortization of Transitional Obligation	(2)	(2)	(2)
Amortization of Past Service Cost	1	1	1
Curtailment Loss	–	1	–
Special Termination Benefits	–	2	–
Expense for Defined Contribution Plan	12	9	6
Net Benefit Plan Expense	$ 24	$ 15	$ 6

The average remaining service period of the active employees covered by the defined benefit pension plan is eight years. The average remaining service period of the active employees covered by the other retirement benefits plan is 13 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

Assumed health care cost trend rates are as follows:

As at December 31	2003
Health care cost trend rate for next year	**10%**
Rate that the trend rate gradually trends to	**5%**
Year that the trend rate reaches the rate which it is expected to remain at	**2014**

Assumed health care cost trend rates have an effect on the amounts reported for the other benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on Total of Service and Interest Cost	$ –	$ –
Effect on Post Retirement Benefit Obligation	$ 2	$ (1)

The Company's pension plan asset allocations are as follows:

	Target Allocation %		% of Plan Assets at December 31		
Asset Category	Normal	Range	2003	2002	Expected Long-term Rate of Return
Domestic Equity	35	25-45	35	32	
Foreign Equity	30	20-40	29	31	
Bonds	30	20-40	27	27	
Real Estate and Other	5	0-20	9	10	
Total	100		100	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposure.

The Company expects to contribute $6 million to the plans in 2004. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2003 (2002 – nil).

Estimated future payments for pension and other benefits are as follows:

2004	$ 12
2005	12
2006	13
2007	13
2008	14
2009 – 2013	84
Total	$ 148

B) Share Appreciation Rights

The Company has in place a program whereby certain employees are granted Share Appreciation Rights ("SAR's") which entitle the employee to receive a cash payment equal to the excess of the market price of the Company's Common Shares at the time of exercise over the exercise price of the right. SAR's granted expire after five years.

The following tables summarize the information about the SAR's:

As at December 31	2003 Outstanding SAR's	2003 Weighted Average Exercise Price *($)*	2002 Outstanding SAR's	2002 Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*				
Outstanding, beginning of year	**2,284,901**	**35.56**	–	–
Granted	**–**	**–**	600,000	38.35
Acquired April 5, in AEC acquisition	**–**	**–**	2,637,421	30.70
Exercised	**(1,101,987)**	**35.17**	(648,902)	27.67
Forfeited	**(7,844)**	**46.28**	(303,618)	39.08
Outstanding, end of year	**1,175,070**	**35.87**	2,284,901	35.56
Exercisable, end of year	**1,175,070**	**35.87**	2,284,901	35.56
U.S. Dollar Denominated *(US$)*				
Outstanding, beginning of year	**1,346,437**	**28.52**	–	–
Acquired April 5, in AEC acquisition	**–**	**–**	1,711,095	28.32
Exercised	**(589,340)**	**27.91**	(223,703)	26.33
Forfeited	**(3,680)**	**30.73**	(140,955)	29.88
Outstanding, end of year	**753,417**	**28.98**	1,346,437	28.52
Exercisable, end of year	**753,417**	**28.98**	1,346,437	28.52

As at December 31, 2003 Range of Exercise Price *($)*	SAR's Outstanding: Number of SAR's	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*			
20.00 to 29.99	600,656	1.05	26.69
30.00 to 39.99	74,720	2.82	38.22
40.00 to 49.99	486,303	2.20	46.39
50.00 to 60.00	13,391	2.32	51.37
	1,175,070	1.65	35.87
U.S. Dollar Denominated *(US$)*			
20.00 to 29.99	336,408	1.75	27.10
30.00 to 40.00	417,009	1.83	30.49
	753,417	1.80	28.98

During the year, the Company recorded compensation costs of $12 million related to the outstanding SAR's (2002 – $4 million).

C) Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSU's"), which are equivalent in value to a Common Share of the Company. DSU's granted to Directors vest immediately. DSU's granted to Senior Executives in 2003 vest over a three year period.

The following table summarizes the information about the DSU's:

	2003		2002	
As at December 31	**Outstanding DSU's**	**Average Share Price** *(C$)*	Outstanding DSU's	Average Share Price *(C$)*
Outstanding, Beginning of Year	**309,167**	**48.69**	–	–
Acquired April 5, in AEC acquisition	–	–	29,631	47.29
Granted, Directors	**37,149**	**48.56**	22,500	49.75
Granted, Senior Executives	**1,976**	**49.91**	260,000	49.75
Exercised	**(29,042)**	**48.04**	(2,964)	48.00
Outstanding, End of Year	**319,250**	**48.68**	309,167	48.69
Exercisable, End of Year	**80,645**	**48.68**	49,167	48.20

During the year, the Company recorded compensation costs of $4 million related to the outstanding DSU's (2002 – $4 million).

D) Performance Share Units

During 2003, the Company put in place a program whereby certain employees may be granted Performance Share Units ("PSU's") which entitle the employee to receive a cash payment, upon vesting, equal to the value of one Common Share of the Company. Each PSU vests at the end of a three year period. Their ultimate value will depend upon EnCana's performance measured over the three year period. Performance will be measured by total stock price change plus dividends relative to a fixed North American oil and gas comparison group. If EnCana's performance is below the median of the comparison group, the units awarded will be forfeited. If EnCana's performance is at or above the median of the comparison group, the value of the PSU's shall be determined by EnCana's relative ranking, with payments ranging from one to two times the market price of an equivalent number of EnCana Common Shares.

The following table summarizes the information about the PSU's:

As at December 31, 2003	**Outstanding PSU's**	**Average Share Price** *(C$)*
Outstanding, Beginning of Year	–	–
Granted	**128,893**	**46.52**
Exercised	–	–
Forfeited	**(2,610)**	**46.52**
Outstanding, End of Year	**126,283**	**46.52**
Exercisable, End of Year	–	–

During the year, the Company recorded compensation costs of $1 million related to the outstanding PSU's (2002 – $nil).

NOTE 17

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities were as follows:

As at December 31	Note	2003	2002
Commodity Price Risk	*A*		
Crude oil		$ (279)	$ (77)
Natural gas		57	191
Gas storage optimization		(25)	(27)
Natural gas liquids		–	(2)
Power		4	(2)
Foreign Currency Risk	*B*	7	(57)
Interest Rate Risk	*C*	44	39
		$ (192)	$ 65

A) Commodity Price Risk

Crude Oil

As at December 31, 2003, the Company's oil risk management activities had an unrecognized loss of $279 million. The contracts were as follows:

	Notional Volumes *(bbls/d)*	Term	Average Price *(US$/bbl)*	Unrecognized Gain/(Loss)
Fixed WTI NYMEX Price	62,500	2004	23.13	$ (162)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(115)
3-way Put Spread	10,000	2005	20.00/25.00/28.77	(3)
				(280)
Crude Oil Marketing Financial Positions (1)				(2)
Crude Oil Marketing Physical Positions (1)				3
				$ (279)

(1) The crude oil marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

Natural Gas

At December 31, 2003, the gas risk management activities had an unrecognized gain of $57 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Physical/ Financial	Term	Price		Unrecognized Gain/(Loss)
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	453	Financial	2004	6.20	C$/mcf	$ 5
NYMEX Fixed price	732	Financial	2004	5.13	US$/mcf	(86)
Chicago Fixed price	40	Financial	2004	5.41	US$/mcf	(1)
AECO Collars	71	Financial	2004	5.34-7.52	C$/mcf	2
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mcf	(16)
NYMEX Collars	50	Physical	2005	2.46-4.90	US$/mcf	(13)
NYMEX Collars	46	Physical	2006–2007	2.46-4.90	US$/mcf	(20)
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis	343	Financial	2004	(0.54)	US$/mcf	22
Fixed NYMEX to Rockies basis	255	Financial	2004	(0.48)	US$/mcf	18
Fixed NYMEX to Rockies basis	413	Physical	2004	(0.50)	US$/mcf	26
Fixed NYMEX to San Juan basis	60	Financial	2004	(0.63)	US$/mcf	1
Fixed NYMEX to San Juan basis	50	Physical	2004	(0.64)	US$/mcf	1
Fixed NYMEX to CIG basis	38	Financial	2004	(0.10)	US$/mcf	–
Fixed NYMEX to AECO basis	877	Financial	2005	(0.66)	US$/mcf	6
Fixed NYMEX to Rockies basis	283	Financial	2005	(0.49)	US$/mcf	16
Fixed NYMEX to Rockies basis	393	Physical	2005	(0.47)	US$/mcf	26
Fixed NYMEX to San Juan basis	75	Financial	2005	(0.63)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	50	Physical	2005	(0.64)	US$/mcf	(1)
Fixed NYMEX to CIG basis	50	Financial	2005	(0.10)	US$/mcf	1
Fixed NYMEX to AECO basis	402	Financial	2006–2008	(0.65)	US$/mcf	24
Fixed NYMEX to Rockies basis	175	Financial	2006–2008	(0.57)	US$/mcf	13
Fixed NYMEX to Rockies basis	207	Physical	2006–2007	(0.49)	US$/mcf	22
Fixed NYMEX to San Juan basis	62	Financial	2006	(0.62)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	42	Physical	2006	(0.64)	US$/mcf	(1)
Fixed NYMEX to CIG basis	31	Financial	2006–2007	(0.10)	US$/mcf	–
Purchase Contracts						
Fixed NYMEX to AECO basis	47	Financial	2004	(0.80)	US$/mcf	(3)
						40
Gas Marketing Financial Positions (1)						(2)
Gas Marketing Physical Positions (1)						19
						$ 57

(1) The gas marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments at various locations and terms over the next nine months to manage the price volatility of the corresponding physical transactions and inventories.

As at December 31, 2003, the unrecognized loss on gas storage optimization risk management activities was $25 million, which was as follows:

	Notional Volumes *(bcf)*	Price *(US$/mcf)*	Unrecognized Gain/(Loss)
Financial Instruments			
Purchases	286.7	5.63	$ 109
Sales	312.4	5.69	(132)
			(23)
Physical Contracts			(2)
			$ (25)

At December 31, 2003, the unrecognized loss on physical contracts of $2 million was more than offset by unrealized gains on physical inventory in storage.

Power

As part of the business combination with AEC, the Company acquired two electricity contracts, one expiring in 2003 and the other in 2005. These contracts were originally entered into as part of an electricity cost management strategy. At December 31, 2003, the unrecognized gain on the remaining contract was $4 million.

B) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Company's operating and financial results. The Company has significant operations outside of Canada, which are subject to these foreign exchange risks.

The following forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2003:

	Amount Hedged *(US$)*	Average Exchange Rate *(C$/US$)*	Unrecognized Gain
2004	$ 88	0.715	$ 7

C) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company's interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrecognized gains on the outstanding financial instruments as at December 31, 2003 were:

	Unrecognized Gain
5.80% Medium Term Notes	$ 12
7.50% Medium Term Notes	9
8.40% Medium Term Notes	6
8.75% Debenture	17
	$ 44

At December 31, 2003, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $22 million (2002 – $16 million).

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

As at December 31	2003 Carrying Amount	2003 Fair Value	2002 Carrying Amount	2002 Fair Value
Financial Assets				
Cash and cash equivalents	$ **148**	$ **148**	$ 116	$ 116
Accounts receivable	**1,367**	**1,367**	1,258	1,258
Financial Liabilities				
Accounts payable, income taxes payable	$ **1,644**	$ **1,644**	$ 1,458	$ 1,458
Long-term debt	**6,375**	**6,767**	5,185	5,461

E) Credit Risk

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board has approved a credit policy governing the Company's credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The majority of the proceeds from the sale of the Company's crude oil production in Ecuador are received from one marketing company. Accounts receivable on these sales are supported by letters of credit issued by a major international financial institution. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

NOTE 18 SUPPLEMENTARY INFORMATION

A) Per Share Amounts

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share.

For the years ended December 31	2003	2002	2001
Weighted Average Common Shares Outstanding – Basic	**474.1**	417.8	255.6
Effect of Stock Options and Other Dilutive Securities	**5.6**	4.8	3.2
Weighted Average Common Shares Outstanding – Diluted	**479.7**	422.6	258.8

B) Net Change in Non-Cash Working Capital from Continuing Operations

For the years ended December 31	2003	2002	2001
Operating Activities			
Accounts receivable and accrued revenues	$ **232**	$ (253)	$ (8)
Inventories	**(241)**	(56)	19
Accounts payable and accrued liabilities	**(118)**	(10)	32
Income taxes payable	**46**	(534)	307
	$ **(81)**	$ (853)	$ 350
Investing Activities			
Accounts payable and accrued liabilities	$ **(83)**	$ 186	$ 55
Financing Activities			
Accounts payable and accrued liabilities	$ **2**	$ (7)	$ 1

C) Supplementary Cash Flow Information

For the years ended December 31	2003	2002	2001
Interest Paid	$ **288**	$ 265	$ 47
Income Taxes (Received) Paid	$ **(195)**	$ 646	$ 22

D) Corporate Reorganization of Canadian Pacific Limited

On February 13, 2001, CPL announced a reorganization whereby its 85% interest in PanCanadian Petroleum Limited (predecessor to PanCanadian Energy Corporation) would be distributed to CPL common shareholders by a Plan of Arrangement. Following shareholder and court approvals, the Plan of Arrangement was implemented on October 1, 2001, and PanCanadian Petroleum Limited became a wholly owned subsidiary of the new public company, PanCanadian Energy Corporation. Effective January 1, 2002, these companies were amalgamated and continued under the name of PanCanadian Energy Corporation.

As part of the CPL reorganization, the Company paid a Special Dividend of C$1,180 million ($754 million), or C$4.60 per Common Share ($2.94 per Common Share), on September 14, 2001. The amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the regular quarterly dividend.

E) Related Party Transactions

In 2001, the Company paid C$50 million ($33 million) relating to a previously contracted purchase price adjustment in respect of C$200 million of capital losses acquired in 1997 from a subsidiary of CPL (the majority shareholder of the Company prior to the corporate reorganization as described previously). The purchase price adjustment, which was contingent on certain economic events, has been recorded as a charge to retained earnings.

Prior to the previously described corporate reorganization of CPL, the Company purchased materials and utilized services from other companies with which it was affiliated. All such transactions were conducted on an arm's length basis and were not material in relation to the Company's overall activities.

NOTE 19 COMMITMENTS AND CONTINGENCIES

Commitments

As at December 31, 2003	2004	2005	2006	2007	2008	Thereafter	**Total**
Pipeline Transportation	$ 449	$ 383	$ 334	$ 314	$ 313	$ 2,116	**$ 3,909**
Purchases of Goods and Services	297	149	76	12	2	–	**536**
Product Purchases	142	47	32	25	24	157	**427**
Operating Leases	44	43	42	40	34	211	**414**
Capital Commitments	259	27	16	–	–	38	**340**
Total	$ 1,191	$ 649	$ 500	$ 391	$ 373	$ 2,522	**$ 5,626**
Product Sales	$ 502	$ 113	$ 69	$ 62	$ 65	$ 359	**$ 1,170**

In addition to the above, the Company has made commitments related to its risk management program (see Note 17).

Contingencies

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the business combination transaction in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. Several of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

Other

The Company is responsible for the retirement of long-lived assets related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $430 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that the Company operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

NOTE 20 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian and U.S. GAAP are described in this note.

Reconciliation of Net Earnings Under Canadian GAAP to U.S. GAAP

For the years ended December 31	Note	**2003**	2002	2001
Net Earnings – Canadian GAAP		**$ 2,360**	$ 812	$ 854
Less:				
Net Earnings from Discontinued Operations – Canadian GAAP		**193**	77	22
Net Earnings from Continuing Operations – Canadian GAAP		**2,167**	735	832
Increase (Decrease) under U.S. GAAP:				
Revenues, net of royalties	*B*	**(205)**	(174)	99
Depreciation, depletion and amortization	*A,G*	**14**	(41)	(37)
Accretion of asset retirement obligation	*G*	**–**	13	8
Additional depletion	*A*	**–**	–	(94)
Interest expense, net	*B*	**70**	126	(11)
Stock-based compensation	*C*	**(1)**	(3)	(10)
Income taxes	*E,G*	**45**	21	6
Net Earnings from Continuing Operations – U.S. GAAP		**2,090**	677	793
Net Earnings from Discontinued Operations – U.S. GAAP		**193**	77	22
Net Earnings before change in accounting policy – U.S. GAAP		**2,283**	754	815
Cumulative effect of change in accounting policy, net of income tax	*G*	**66**	–	–
Net Earnings – U.S. GAAP		**$ 2,349**	$ 754	$ 815
Net Earnings per Common Share before change in accounting policy – U.S. GAAP				
Basic		**$ 4.82**	$ 1.81	$ 3.19
Diluted		**$ 4.76**	$ 1.78	$ 3.15
Net Earnings per Common Share including cumulative effect of change in accounting policy – U.S. GAAP				
Basic		**$ 4.95**	$ 1.81	$ 3.19
Diluted		**$ 4.90**	$ 1.78	$ 3.15

Consolidated Statement of Earnings – U.S. GAAP

For the years ended December 31	Note	2003	2002	2001
Revenues, Net of Royalties	*B*	**$ 10,011**	$ 6,102	$ 3,343
Expenses				
Production and mineral taxes		**189**	119	77
Transportation and selling		**545**	364	111
Operating		**1,297**	813	448
Purchased product		**3,455**	2,200	739
Depreciation, depletion and amortization	*A,G*	**2,208**	1,345	641
Administrative	*C*	**174**	122	64
Interest, net	*B*	**217**	164	45
Accretion of asset retirement obligation	*G*	**19**	–	–
Foreign exchange (gain) loss		**(601)**	(14)	12
Stock-based compensation		**18**	–	–
Gain on corporate disposition		**–**	(33)	–
Net Earnings Before Income Tax		**2,490**	1,022	1,206
Income tax expense	*E*	**400**	345	413
Net Earnings from Continuing Operations – U.S. GAAP		**2,090**	677	793
Net Earnings from Discontinued Operations – U.S. GAAP		**193**	77	22
Net Earnings before change in accounting policy – U.S. GAAP		**$ 2,283**	$ 754	$ 815
Cumulative effect of change in accounting policy, net of tax	*G*	**66**	–	–
Net Earnings – U.S. GAAP		**$ 2,349**	$ 754	$ 815
Net Earnings from Continuing Operations per Common Share – U.S. GAAP				
Basic		**$ 4.41**	$ 1.62	$ 3.10
Diluted		**$ 4.36**	$ 1.60	$ 3.06
Net Earnings per Common Share before change in accounting policy – U.S. GAAP				
Basic		**$ 4.82**	$ 1.81	$ 3.19
Diluted		**$ 4.76**	$ 1.78	$ 3.15
Net Earnings per Common Share including cumulative effect of change in accounting policy – U.S. GAAP				
Basic		**$ 4.95**	$ 1.81	$ 3.19
Diluted		**$ 4.90**	$ 1.78	$ 3.15

Statement of Other Comprehensive Income

For the years ended December 31	Note	2003	2002	2001
Net Earnings – U.S. GAAP		**$ 2,349**	$ 754	$ 815
Adoption of FAS 133, net of tax	*B,F*	**–**	–	(53)
Change in Fair Value of Financial Instruments	*B,F*	**4**	(7)	49
Foreign Currency Translation Adjustment	*D*	**1,046**	136	(210)
Other		**6**	(6)	–
Other Comprehensive Income		**$ 3,405**	$ 877	$ 601

Condensed Consolidated Balance Sheet

As at December 31	Note	2003 As Reported	2003 U.S. GAAP	2002 As Reported	2002 U.S. GAAP
Assets					
Current Assets		$ 2,088	$ 2,088	$ 3,810	$ 3,821
Financial Assets	*B*	–	145	–	127
Property, Plant and Equipment, net	*A,G*	19,545	19,419	14,247	14,038
Investments and Other Assets	*B*	566	569	292	299
Goodwill		1,911	1,911	1,563	1,563
		$24,110	$24,132	$19,912	$19,848
Liabilities and Shareholders' Equity					
Current Liabilities		$ 1,931	$ 1,931	$ 2,692	$ 2,705
Financial Liabilities	*B*	–	380	–	208
Long-Term Debt		6,088	6,088	5,051	5,051
Other Liabilities	*B*	21	8	54	53
Asset Retirement Obligation	*G*	430	430	309	303
Future Income Taxes	*E,G*	4,362	4,223	3,088	2,991
		12,832	13,060	11,194	11,311
Share Capital	*C*	5,305	5,318	5,511	5,524
Share Options, net		55	55	84	84
Paid in Surplus		18	18	51	51
Retained Earnings		5,276	5,076	3,523	3,325
Foreign Currency Translation Adjustment	*D*	624	–	(451)	–
Accumulated Other Comprehensive Income		–	605	–	(447)
		11,278	11,072	8,718	8,537
		$24,110	$24,132	$19,912	$19,848

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

For the years ended December 31	2003	2002	2001
Cash From Operating Activities			
Net earnings from continuing operations	$ 2,090	$ 677	$ 793
Depreciation, depletion and amortization	2,208	1,345	641
Future income taxes	456	383	89
Accretion of asset retirement obligation	19	–	–
Foreign exchange (gain) loss	(545)	(23)	35
Unrealized loss (gain) on risk management contracts	135	48	(88)
Other	57	(163)	(7)
Cash flow from continuing operations	4,420	2,267	1,463
Cash flow from discontinued operations	39	152	31
Cash Flow	4,459	2,419	1,494
Net change in other assets and liabilities	(84)	(17)	(40)
Net change in non-cash working capital from continuing operations	(81)	(853)	350
Net change in non-cash working capital from discontinued operations	17	64	(29)
	$ 4,311	$ 1,613	$ 1,775
Cash Used in Investing Activities	$ (3,729)	$ (2,595)	$ (1,092)
Cash (Used in) From Financing Activities	$ (540)	$ 491	$ (214)

Notes:

A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize escalated pricing to determine whether impairment exists. However, the impaired amount is measured using the fair value of reserves.

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

B) Derivative Instruments and Hedging

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 effective January 1, 2001. FAS 133 requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under FAS 133.

Realized and unrealized gain/(loss) on derivatives related to:

For the years ended December 31	**2003**	2002	2001
Commodity Prices (Revenues, net of royalties)	$ **(205)**	$ (174)	$ 99
Interest and Currency Swaps (Interest, net)	**70**	126	(11)
Total Unrealized (Loss) Gain	$ **(135)**	$ (48)	$ 88

The adoption of FAS 133 at January 1, 2001 resulted in recognition of derivative assets with a fair value of $572 million, derivative liabilities with a fair value of $628 million, a $78 million ($53 million, net of tax) charge to other comprehensive income and a $22 million ($15 million, net of tax) increase to net earnings under U.S. GAAP.

As at December 31, 2003, it is estimated that over the following 12 months, $4 million ($2 million, net of tax) will be reclassified into net earnings from other comprehensive income.

C) Stock-based Compensation – CPL Reorganization

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and Directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 15.

Under FASB Interpretation No. 44 "Accounting for Certain Transactions involving Stock Compensation", compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the Corporate reorganization, as described in Note 18, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by PanCanadian as described in Note 15. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) Foreign Currency Translation Adjustments

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in Shareholders' Equity.

E) Future Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

The future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31	**2003**	2002	2001
Using Canadian GAAP			
Net earnings before income tax	**$ 2,612**	$ 1,101	$ 1,251
Canadian Statutory Rate	**40.95%**	42.3%	42.8%
Expected Income Tax	**$ 1,070**	$ 467	$ 536
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**231**	147	74
Canadian resource allowance	**(258)**	(200)	(167)
Large corporations tax	**27**	23	9
Statutory rate differences	**(50)**	(36)	(12)
Effect of tax rate changes	**(359)**	(20)	(53)
Non-taxable capital gains	**(119)**	(9)	–
Previously unrecognized capital losses	**(119)**	–	–
Other	**22**	(6)	32
	445	366	419
U.S. GAAP Adjustments to Net Earnings Before Income Tax	**(122)**	(79)	(45)
Expected Income Tax	**(50)**	(33)	(19)
Depletion	**–**	–	2
Other	**5**	12	11
	(45)	(21)	(6)
Income Tax – U.S. GAAP	**$ 400**	$ 345	$ 413
Effective Tax Rate	**16.1%**	33.8%	34.2%

The net deferred income tax liability is comprised of:

As at December 31	**2003**	2002
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 3,416**	$ 2,714
Timing of partnership items	**1,162**	513
Future Tax Assets		
Net operating losses carried forward	**(174)**	(203)
Other	**(181)**	(33)
Net Future Income Tax Liability	**$ 4,223**	$ 2,991

F) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of FAS 133. At December 31, 2003, accumulated other comprehensive income related to these items was a loss of $9 million, net of tax.

G) Asset Retirement Obligation

The Company early adopted the Canadian accounting standard for asset retirement obligations, as outlined in the CICA handbook section 3110. This standard is equivalent to U.S. FAS 143, Accounting for Asset Retirement Obligations, which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligation, however a difference is created in how the transition amounts are disclosed.

U.S. GAAP requires the cumulative impact of a change in an accounting policy be presented in the current year Consolidated Statement of Earnings and prior periods not be restated. The following table illustrates the pro forma impact on the Company's financial results under U.S. GAAP if the prior periods had been restated:

As at and for the years ended December 31	As Reported	Change	As Restated
2002 Consolidated Balance Sheet			
Assets			
Current assets	$ 3,821	$ (11)	$ 3,810
Property, plant and equipment, net	14,038	94	14,132
Liabilities			
Current liabilities	$ 2,705	$ (13)	$ 2,692
Other liabilities & asset retirement obligation	356	6	362
Future income taxes	2,991	23	3,014
Shareholders' Equity			
Retained earnings	$ 3,325	$ 66	$ 3,391
Foreign currency translation adjustment	(447)	1	(446)
2002 Consolidated Statement of Earnings			
Net Earnings	$ 754	$ 34	$ 788
Net Earnings per Common Share – Diluted	$ 1.78	$ 0.08	$ 1.86
2001 Consolidated Statement of Earnings			
Net Earnings	$ 815	$ 22	$ 837
Net Earnings per Common Share – Diluted	$ 3.15	$ 0.08	$ 3.23

H) Recent Accounting Pronouncements

During 2003, the following new standard was issued:

Variable Interest Entities

In December 2003, the Financial Accounting Standards Board ("FASB") in the United States issued Interpretation Number 46R "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51". The standard mandates that variable interest entities be consolidated by their primary beneficiary. The standard is effective the first reporting period ending after March 15, 2004 for all entities with the exception of special purpose entities as defined in prior accounting guidance. The standard is effective for the first period ending after December 15, 2003 for previously defined special purpose entities. In Canada, the Accounting Standards Board ("AcSB") has suspended the effective dates for Accounting Guideline AcG15, "Consolidation of Variable Interest Entities" in order to amend the guideline to harmonize with the corresponding U.S. guidance. The AcSB plans to issue an exposure draft in the immediate future with an effective period beginning on or after November 1, 2004.

At December 31, 2003, the Company did not have any variable interest in variable-interest entities.

The following unaudited disclosures on standardized measures of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities".

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, year end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserve evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs, and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's Syncrude (disposed of in 2003) and Midstream & Marketing interests.

EnCana Corporation

SUPPLEMENTARY OIL AND GAS INFORMATION *(unaudited)*

Net Proved Reserves (EnCana Share After Royalties) (1,2)

Constant Pricing	Natural Gas (*billions of cubic feet*)					Crude Oil and Natural Gas Liquids (*millions of barrels*)					
	Canada	United States	United Kingdom	Other	**Total**	Canada	United States	Ecuador	United Kingdom	Other	**Total**
2001											
Beginning of year	3,350	208	10	–	**3,568**	348.0	16.7	–	23.7	5.0	**393.4**
Revisions and improved recovery	59	6	–	–	**65**	5.0	1.6	–	2.1	–	**8.7**
Extensions and discoveries	448	13	–	–	**461**	15.0	2.0	–	–	–	**17.0**
Purchase of reserves in place	1	25	–	–	**26**	–	–	–	–	–	**–**
Sale of reserves in place	(1)	–	–	–	**(1)**	(48.0)	–	–	–	(5.0)	**(53.0)**
Production	(353)	(16)	(3)	–	**(372)**	(33.4)	(0.7)	–	(4.2)	–	**(38.3)**
End of Year	3,504	236	7	–	**3,747**	286.6	19.6	–	21.6	–	**327.8**
Developed	2,908	172	7	–	**3,087**	245.3	14.9	–	21.6	–	**281.8**
Undeveloped	596	64	–	–	**660**	41.3	4.7	–	–	–	**46.0**
Total	3,504	236	7	–	**3,747**	286.6	19.6	–	21.6	–	**327.8**
2002											
Beginning of year	3,504	236	7	–	**3,747**	286.6	19.6	–	21.6	–	**327.8**
Purchase of AEC reserves in place	2,686	944	–	–	**3,630**	233.7	6.5	168.4	–	–	**408.6**
Revisions and improved recovery	(1,140)	731	7	–	**(402)**	(15.5)	4.6	(33.5)	(9.1)	–	**(53.5)**
Extensions and discoveries	726	319	10	–	**1,055**	96.9	3.3	31.1	89.2	–	**220.5**
Purchase of reserves in place	30	530	–	–	**560**	4.9	9.9	–	–	–	**14.8**
Sale of reserves in place	(129)	(73)	–	–	**(202)**	(18.2)	(0.7)	–	–	–	**(18.9)**
Production	(604)	(114)	(4)	–	**(722)**	(46.5)	(2.3)	(10.2)	(4.1)	–	**(63.1)**
End of Year	5,073	2,573	20	–	**7,666**	541.9	40.9	155.8	97.6	–	**836.2**
Developed	4,139	1,446	9	–	**5,594**	299.2	21.9	104.6	8.3	–	**434.0**
Undeveloped	934	1,127	11	–	**2,072**	242.7	19.0	51.2	89.3	–	**402.2**
Total	5,073	2,573	20	–	**7,666**	541.9	40.9	155.8	97.6	–	**836.2**
2003											
Beginning of year	5,073	2,573	20	–	**7,666**	541.9	40.9	155.8	97.6	–	**836.2**
Revisions and improved recovery	73	1	3	–	**77**	32.3	0.5	0.4	23.5	–	**56.7**
Extensions and discoveries	867	706	–	90	**1,663**	110.9	7.4	11.9	–	0.9	**131.1**
Purchase of reserves in place	9	152	8	–	**169**	1.3	0.9	17.3	7.1	–	**26.6**
Sale of reserves in place	(60)	(88)	–	(90)	**(238)**	(0.2)	(4.7)	(5.1)	–	(0.9)	**(10.9)**
Production	(706)	(215)	(5)	–	**(926)**	(56.8)	(3.4)	(18.6)	(3.7)	–	**(82.5)**
End of Year	5,256	3,129	26	–	**8,411**	629.4	41.6	161.7	124.5	–	**957.2**
Developed	3,984	1,833	13	–	**5,830**	306.1	26.3	115.0	16.7	–	**464.1**
Undeveloped	1,272	1,296	13	–	**2,581**	323.3	15.3	46.7	107.8	–	**493.1**
Total	5,256	3,129	26	–	**8,411**	629.4	41.6	161.7	124.5	–	**957.2**

Notes:

(1) Definitions:

a. "Net" reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.

b. "Proved" reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

c. "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

d. "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

OTHER DISCLOSURES ABOUT OIL AND GAS ACTIVITIES

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Future cash inflows	**35,126**	29,890	10,768	**17,472**	9,398	845	**3,533**	3,368	–
Future production and development costs	**14,018**	8,686	3,070	**2,889**	3,360	285	**987**	908	–
Undiscounted pre-tax cash flows	**21,108**	21,204	7,698	**14,583**	6,038	560	**2,546**	2,460	–
Future income taxes	**5,874**	6,353	2,604	**4,960**	1,504	24	**536**	585	–
Future net cash flows	**15,234**	14,851	5,094	**9,623**	4,534	536	**2,010**	1,875	–
Less discount of net cash flows using a 10% rate	**5,219**	6,018	2,034	**4,735**	2,383	236	**643**	617	–
Discounted future net cash flows	**10,015**	8,833	3,060	**4,888**	2,151	300	**1,367**	1,258	–

	United Kingdom			Other			Total		
($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Future cash inflows	**3,483**	2,565	414	**–**	–	–	**59,614**	45,221	12,027
Future production and development costs	**1,969**	1,233	161	**–**	–	–	**19,863**	14,187	3,516
Undiscounted pre-tax cash flows	**1,514**	1,332	253	**–**	–	–	**39,751**	31,034	8,511
Future income taxes	**456**	483	53	**–**	–	–	**11,826**	8,925	2,681
Future net cash flows	**1,058**	849	200	**–**	–	–	**27,925**	22,109	5,830
Less discount of net cash flows using a 10% rate	**493**	438	60	**–**	–	–	**11,090**	9,456	2,330
Discounted future net cash flows	**565**	411	140	**–**	–	–	**16,835**	12,653	3,500

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Balance, beginning of year	**8,833**	3,060	7,844	**2,151**	300	145	**1,258**	–	–
Changes resulting from:									
Sales of oil and gas produced during the period	**(3,429)**	(2,092)	(1,701)	**(889)**	(329)	(47)	**(258)**	(157)	–
Discoveries and extensions, net of related costs	**1,272**	1,293	487	**1,381**	293	36	**126**	330	–
Purchases of proved AEC reserves in place	**–**	6,810	–	**–**	1,044	–	**–**	1,830	–
Purchases of proved reserves in place	**26**	93	4	**340**	613	30	**93**	–	–
Sales of proved reserves in place	**(95)**	(371)	(234)	**(108)**	(72)	–	**(54)**	–	–
Net change in prices and production costs	**242**	3,358	(7,561)	**2,751**	194	109	**(47)**	–	–
Revisions to quantity estimates	**416**	(1,345)	90	**4**	667	12	**4**	(354)	–
Accretion of discount	**1,636**	455	1,197	**304**	56	21	**182**	–	–
Future development costs incurred, net of changes	**340**	101	180	**534**	54	(70)	**89**	–	–
Other	**470**	(67)	21	**157**	(51)	–	**(27)**	–	–
Net change in income taxes	**304**	(2,462)	2,733	**(1,737)**	(618)	64	**1**	(391)	–
Balance, end of year	**10,015**	8,833	3,060	**4,888**	2,151	300	**1,367**	1,258	–

	United Kingdom			Other			Total		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Balance, beginning of year	**411**	140	147	**–**	–	49	**12,653**	3,500	8,185
Changes resulting from:									
Sales of oil and gas produced during the period	**(83)**	(81)	(89)	**–**	–	–	**(4,659)**	(2,659)	(1,837)
Discoveries and extensions, net of related costs	**–**	594	–	**–**	–	–	**2,779**	2,510	523
Purchases of proved AEC reserves in place	**–**	–	–	**–**	–	–	**–**	9,684	–
Purchases of proved reserves in place	**57**	–	–	**–**	–	–	**516**	706	34
Sales of proved reserves in place	**–**	–	–	**–**	–	(49)	**(257)**	(443)	(283)
Net change in prices and production costs	**(119)**	(1)	12	**–**	–	–	**2,827**	3,551	(7,440)
Revisions to quantity estimates	**157**	(53)	19	**–**	–	–	**581**	(1,085)	121
Accretion of discount	**91**	14	32	**–**	–	–	**2,213**	525	1,250
Future development costs incurred, net of changes	**108**	3	(4)	**–**	–	–	**1,071**	158	106
Other	**(38)**	(8)	–	**–**	–	–	**562**	(126)	21
Net change in income taxes	**(19)**	(197)	23	**–**	–	–	**(1,451)**	(3,668)	2,820
Balance, end of year	**565**	411	140	**–**	–	–	**16,835**	12,653	3,500

Results of Operations

	Canada			United States			Ecuador		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Oil and gas revenues, net of royalties, transportation and selling costs	**4,189**	2,630	2,043	**1,091**	406	73	**367**	224	–
Operating costs, production and mineral taxes	**760**	538	342	**202**	77	26	**109**	67	–
Depreciation, depletion and amortization	**1,511**	871	385	**297**	206	31	**159**	79	–
Operating income (loss)	**1,918**	1,221	1,316	**592**	123	16	**99**	78	–
Income taxes	**218**	456	423	**219**	47	6	**17**	28	–
Results of operations	**1,700**	765	893	**373**	76	10	**82**	50	–

	United Kingdom			Other			Total		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Oil and gas revenues, net of royalties, transportation and selling costs	**102**	92	99	–	–	–	**5,749**	3,352	2,215
Operating costs, production and mineral taxes	**19**	11	10	**20**	29	1	**1,110**	722	379
Depreciation, depletion and amortization	**74**	39	42	**83**	35	17	**2,124**	1,230	475
Operating income (loss)	**9**	42	47	**(103)**	(64)	(18)	**2,515**	1,400	1,361
Income taxes	**17**	17	17	**(4)**	–	–	**467**	548	446
Results of operations	**(8)**	25	30	**(99)**	(64)	(18)	**2,048**	852	915

Capitalized Costs

	Canada			United States			Ecuador		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Proved oil and gas properties	**18,549**	12,504	7,704	**3,485**	2,769	471	**1,372**	1,000	–
Unproved oil and gas properties	**1,981**	1,573	203	**501**	415	116	**70**	60	–
Total capital cost	**20,530**	14,077	7,907	**3,986**	3,184	587	**1,442**	1,060	–
Accumulated DD&A	**7,498**	4,770	3,893	**516**	262	29	**188**	73	–
Net capitalized costs	**13,032**	9,307	4,014	**3,470**	2,922	558	**1,254**	987	–

	United Kingdom			Other			Total		
Years ended December 31 ($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Proved oil and gas properties	**675**	445	288	–	–	–	**24,081**	16,718	8,463
Unproved oil and gas properties	**77**	3	44	**317**	226	144	**2,946**	2,277	507
Total capital cost	**752**	448	332	**317**	226	144	**27,027**	18,995	8,970
Accumulated DD&A	**230**	136	88	**206**	98	92	**8,638**	5,339	4,102
Net capitalized costs	**522**	312	244	**111**	128	52	**18,389**	13,656	4,868

Costs Incurred

Years ended December 31 ($ millions)	Canada 2003	Canada 2002	Canada 2001	United States 2003	United States 2002	United States 2001	Ecuador 2003	Ecuador 2002	Ecuador 2001
Acquisitions									
– AEC unproved reserves	**–**	1,496	–	**–**	444	–	**–**	221	–
– other unproved reserves	**47**	12	4	**21**	202	13	**80**	–	–
– AEC proved reserves	**–**	3,540	–	**–**	1,024	–	**–**	686	–
– other proved reserves	**207**	78	1	**115**	457	34	**59**	–	–
Total acquisitions	**254**	5,126	5	**136**	2,127	47	**139**	907	–
Exploration costs	**846**	403	304	**187**	226	129	**20**	35	–
Development	**2,131**	902	592	**651**	282	7	**111**	133	–
Total costs incurred	**3,231**	6,431	901	**974**	2,635	183	**270**	1,075	–

Years ended December 31 ($ millions)	United Kingdom 2003	United Kingdom 2002	United Kingdom 2001	Other 2003	Other 2002	Other 2001	Total 2003	Total 2002	Total 2001
Acquisitions									
– AEC unproved reserves	**–**	–	–	**–**	–	–	**–**	2,161	–
– other unproved reserves	**16**	–	–	**–**	–	–	**164**	214	17
– AEC proved reserves	**–**	–	–	**–**	–	–	**–**	5,250	–
– other proved reserves	**95**	–	–	**–**	–	4	**476**	535	39
Total acquisitions	111	–	–	**–**	–	4	**640**	8,160	56
Exploration costs	**30**	16	25	**78**	118	41	**1,161**	798	499
Development	**96**	66	17	**–**	–	–	**2,989**	1,383	620
Total costs incurred	**237**	82	42	**78**	118	45	**4,790**	10,341	1,175

EnCana Corporation

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

	2003					2002**		
(US$ millions, except per share amounts)	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Cash Flow	**4,459**	1,254	977	1,007	1,221	935	651	591
Per share – Basic	**9.41**	2.71	2.06	2.10	2.54	1.96	1.37	1.28
– Diluted	**9.30**	2.69	2.04	2.08	2.52	1.94	1.35	1.26
Net Earnings	**2,360**	426	290	807	837	282	136	303
Per share – Basic	**4.98**	0.92	0.61	1.68	1.74	0.59	0.29	0.66
– Diluted	**4.92**	0.91	0.61	1.67	1.73	0.58	0.28	0.65
Net Earnings from Continuing Operations	**2,167**	426	286	805	650	248	79	318
Per share – Basic	**4.57**	0.92	0.60	1.67	1.35	0.52	0.17	0.69
– Diluted	**4.52**	0.91	0.60	1.66	1.34	0.51	0.16	0.68
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax)*	**1,734**	313	274	637	510	242	179	205
Per share – Diluted	**3.62**	0.67	0.57	1.31	1.05	0.50	0.37	0.44
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) and tax rate change gain	**1,375**	316	274	275	510	239	188	179
Per share – Diluted	**2.87**	0.68	0.57	0.56	1.05	0.49	0.39	0.38
Foreign Exchange Rates *(US$ per C$1)*								
Average	**0.716**	0.760	0.725	0.715	0.662	0.637	0.640	0.643
Period end	**0.774**	0.774	0.741	0.738	0.681	0.633	0.631	0.659

	2003					2002**		
Shares	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Common Shares Outstanding *(millions)*								
Period end	**460.6**	460.6	465.0	479.9	480.6	478.9	477.4	476.3
Average – Basic	**474.1**	462.3	473.4	480.6	479.9	477.9	476.8	461.1
Average – Diluted	**479.7**	465.9	477.9	484.4	484.3	482.6	482.2	467.3
Price Range *($ per share)*								
TSX – C$								
High	**53.55**	52.25	52.79	53.55	50.00	50.05	48.50	51.00
Low	**44.60**	44.60	47.49	45.26	45.74	40.60	37.25	43.50
Close	**51.00**	51.00	48.90	51.70	47.75	48.78	48.00	46.70
NYSE – US$								
High	**40.08**	40.08	38.34	39.63	33.50	32.29	31.90	32.36
Low	**29.91**	33.46	34.00	30.45	29.91	25.57	23.50	28.31
Close	**39.44**	39.44	36.38	38.37	32.36	31.10	30.10	30.60
Share Volume Traded *(millions)*	**476.4**	141.1	117.9	107.2	110.2	122.3	105.5	113.2
Share Value Traded *(C$ millions weekly average)*	**443.6**	522.8	443.4	405.4	402.9	418.3	366.3	412.6

Ratios	
Debt to Capitalization	**34%**
Return on Capital Employed	**17%**
Return on Common Equity	**24%**

* The Company is required to translate long-term debt denominated in U.S. dollars issued in Canada into Canadian dollars at the period end exchange rate with any resulting adjustments recorded in the Consolidated Statement of Earnings.

** Q1 2002 has been excluded as it represents activity prior to the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd.

Financial Statistics (continued)

Net Capital Investment *(US$ millions)*	2003	Pro forma 2002
Upstream		
Canada	$ 2,937	$ 1,601
United States	830	616
Ecuador	265	212
United Kingdom	112	82
Other Countries	78	113
	4,222	2,624
Midstream & Marketing	223	51
Corporate	57	46
Core Capital	4,502	2,721
Acquisitions		
Upstream		
Property	510	786
Corporate	207	–
Midstream & Marketing	53	–
Corporate Division	50	–
Dispositions		
Upstream	(301)	(385)
Corporate	(14)	(60)
Net Capital Investment – Continuing Operations	5,007	3,062
Discontinued Operations	(1,585)	172
Total Net Capital Investment	$ 3,422	$ 3,234

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Pro forma Operating Statistics – After Royalties

Sales Volumes	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Year*	2002 Q4	2002 Q3	2002 Q2	2002 Q1*
Produced Gas *(MMcf/d)*										
Canada										
Production	**1,935**	2,008	1,914	1,899	1,922	1,953	1,943	1,959	1,980	1,930
Inventory withdrawal/ (injection)	**30**	–	–	–	120	22	117	(51)	(90)	113
Canada Sales	**1,965**	2,008	1,914	1,899	2,042	1,975	2,060	1,908	1,890	2,043
United States	**588**	654	604	558	534	395	516	423	345	295
United Kingdom	**13**	20	7	12	13	10	8	9	8	11
	2,566	2,682	2,525	2,469	2,589	2,380	2,584	2,340	2,243	2,349
Oil and Natural Gas Liquids *(bbls/d)*										
North America										
Light and Medium Oil	**54,459**	56,585	54,597	52,733	53,890	59,222	55,265	58,321	58,885	64,531
Heavy Oil	**87,867**	95,059	94,985	82,001	79,171	69,465	77,090	70,795	67,558	62,237
Natural Gas Liquids**										
Canada	**14,278**	13,348	13,758	14,740	15,291	14,778	15,987	13,985	14,168	14,968
United States	**9,291**	9,479	9,530	10,194	7,943	7,019	10,016	5,901	6,368	5,757
Total North America	**165,895**	174,471	172,870	159,668	156,295	150,484	158,358	149,002	146,979	147,493
Ecuador										
Production	**51,089**	72,731	54,582	36,754	39,893	36,521	34,856	37,447	37,702	36,082
Transferred to OCP Pipeline***	**(3,213)**	–	(4,919)	(2,039)	(5,941)	–	–	–	–	–
Over/(under) lifting	**(1,355)**	4,621	(9,856)	2,506	(2,679)	70	1,044	2,316	5,088	(8,295)
Ecuador Sales	**46,521**	77,352	39,807	37,221	31,273	36,591	35,900	39,763	42,790	27,787
United Kingdom	**10,128**	15,067	5,813	9,019	10,610	10,528	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids	**222,544**	266,890	218,490	205,908	198,178	197,603	202,044	198,303	201,735	188,169
Total *(BOE/d)*	**650,211**	713,890	639,323	617,408	629,678	594,270	632,711	588,303	575,568	579,669
Syncrude *(bbls/d)*	**7,629**	–	3,399	7,316	20,070	31,267	33,918	35,585	24,152	31,337

* Volumes have been presented on a pro forma basis to include pre-merger activity of Alberta Energy Company Ltd.

** Natural gas liquids include condensate volumes.

*** Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

U.S. Dollar Operating Statistics – After Royalties

	2003					2002*		
Per-unit Results	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas – Canada *(US$/Mcf)*								
Price, net of royalties	**4.87**	4.41	4.61	4.92	5.53	3.60	2.29	2.93
Production and mineral taxes	**0.07**	0.10	0.08	0.08	0.02	0.07	0.04	0.10
Transportation and selling	**0.38**	0.44	0.40	0.35	0.33	0.30	0.21	0.21
Operating expenses	**0.48**	0.45	0.50	0.47	0.48	0.44	0.42	0.40
Netback excluding hedge	**3.94**	3.42	3.63	4.02	4.70	2.79	1.62	2.22
Financial Hedge	**(0.13)**	0.25	(0.03)	(0.26)	(0.49)	(0.06)	0.21	(0.08)
Netback including hedge	**3.81**	3.67	3.60	3.76	4.21	2.73	1.83	2.14
Produced Gas – United States *(US$/Mcf)*								
Price, net of royalties	**4.88**	4.71	4.82	4.74	5.32	3.48	2.78	2.51
Production and mineral taxes	**0.47**	0.42	0.46	0.46	0.57	0.34	0.22	0.23
Transportation and selling	**0.40**	0.51	0.39	0.36	0.32	0.46	0.76	0.23
Operating expenses	**0.28**	0.29	0.33	0.31	0.20	0.23	0.28	0.31
Netback excluding hedge	**3.73**	3.49	3.64	3.61	4.23	2.45	1.52	1.74
Financial Hedge	**0.02**	(0.13)	(0.16)	(0.22)	0.67	0.34	0.47	0.05
Netback including hedge	**3.75**	3.36	3.48	3.39	4.90	2.79	1.99	1.79
Produced Gas – Total North America *(US$/Mcf)*								
Price, net of royalties	**4.87**	4.49	4.66	4.88	5.49	3.58	2.37	2.86
Production and mineral taxes	**0.16**	0.18	0.17	0.17	0.14	0.12	0.08	0.12
Transportation and selling	**0.39**	0.46	0.40	0.35	0.33	0.33	0.31	0.22
Operating expenses	**0.43**	0.41	0.46	0.43	0.42	0.40	0.39	0.39
Netback excluding hedge	**3.89**	3.44	3.63	3.93	4.60	2.73	1.59	2.13
Financial Hedge	**(0.10)**	0.16	(0.06)	(0.25)	(0.25)	0.02	0.26	(0.06)
Netback including hedge	**3.79**	3.60	3.57	3.68	4.35	2.75	1.85	2.07
Light and Medium Oil – North America *(US$/bbl)*								
Price, net of royalties	**26.61**	25.53	24.31	27.43	29.34	24.39	24.09	23.37
Production and mineral taxes	**0.29**	0.73	(1.35)	0.71	1.08	0.48	0.51	0.14
Transportation and selling	**1.42**	1.33	0.71	1.73	1.95	1.22	1.04	0.62
Operating expenses	**6.00**	6.28	5.93	6.07	5.68	5.15	4.72	5.29
Netback excluding hedge	**18.90**	17.19	19.02	18.92	20.63	17.54	17.82	17.32
Financial Hedge	**(4.07)**	(3.74)	(3.24)	(2.81)	(6.54)	(0.91)	(0.64)	(1.16)
Netback including hedge	**14.83**	13.45	15.78	16.11	14.09	16.63	17.18	16.16
Heavy Oil – North America *(US$/bbl)*								
Price, net of royalties	**19.61**	18.43	17.93	20.07	22.62	17.38	19.67	17.76
Production and mineral taxes	**(0.03)**	0.09	(0.49)	0.34	(0.02)	0.54	0.03	0.04
Transportation and selling	**1.24**	1.54	0.58	1.37	1.56	0.93	0.81	0.48
Operating expenses	**5.67**	4.95	5.93	6.18	5.70	4.12	4.96	4.39
Netback excluding hedge	**12.73**	11.85	11.91	12.18	15.38	11.79	13.87	12.85
Financial Hedge	**(3.91)**	(3.81)	(3.17)	(2.24)	(6.69)	(0.84)	(0.65)	(0.55)
Netback including hedge	**8.82**	8.04	8.74	9.94	8.69	10.95	13.22	12.30
Total Crude Oil – North America *(US$/bbl)*								
Price, net of royalties	**22.29**	21.08	20.26	22.95	25.34	20.31	21.67	20.37
Production and mineral taxes	**0.09**	0.33	(0.80)	0.49	0.43	0.51	0.25	0.08
Transportation and selling	**1.31**	1.46	0.63	1.51	1.72	1.05	0.92	0.55
Operating expenses	**5.80**	5.45	5.93	6.13	5.70	4.55	4.85	4.81
Netback excluding hedge	**15.09**	13.84	14.50	14.82	17.49	14.20	15.65	14.93
Financial Hedge	**(3.97)**	(3.78)	(3.19)	(2.47)	(6.63)	(0.87)	(0.64)	(0.83)
Netback including hedge	**11.12**	10.06	11.31	12.35	10.86	13.33	15.01	14.10

* Q1 2002 has been excluded as it represents activity prior to the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd.

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

U.S. Dollar Operating Statistics – After Royalties

	2003					2002*		
Per-unit Results *(continued)*	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Natural Gas Liquids – Canada *(US$/bbl)*								
Price, net of royalties	**24.26**	25.13	23.52	21.02	27.31	21.75	17.61	17.41
Production and mineral taxes	**–**	–	–	–	–	–	–	–
Transportation and selling	**0.17**	0.13	0.58	–	–	–	–	–
Netback	**24.09**	25.00	22.94	21.02	27.31	21.75	17.61	17.41
Natural Gas Liquids – United States *(US$/bbl)*								
Price, net of royalties	**26.97**	26.68	25.50	24.64	32.18	25.14	25.64	23.57
Production and mineral taxes	**2.03**	2.69	2.64	1.21	1.55	0.94	1.32	1.37
Transportation and selling	**–**	–	–	–	–	–	–	–
Netback	**24.94**	23.99	22.86	23.43	30.63	24.20	24.32	22.20
Natural Gas Liquids –Total North America *(US$/bbl)*								
Price, net of royalties	**25.33**	25.77	24.33	22.50	28.98	23.06	19.99	19.32
Production and mineral taxes	**0.80**	1.12	1.08	0.50	0.53	0.36	0.39	0.42
Transportation and selling	**0.10**	0.08	0.35	–	–	–	–	–
Netback	**24.43**	24.57	22.90	22.00	28.45	22.70	19.60	18.90
Total Liquids – Canada *(US$/bbl)*								
Price, net of royalties	**22.47**	21.41	20.54	22.76	25.55	20.46	21.27	20.07
Production and mineral taxes	**0.08**	0.30	(0.73)	0.44	0.38	0.46	0.22	0.08
Transportation and selling	**1.21**	1.36	0.62	1.36	1.54	0.94	0.83	0.49
Operating expenses	**5.27**	5.01	5.43	5.53	5.11	4.06	4.38	4.32
Netback excluding hedge	**15.91**	14.74	15.22	15.43	18.52	15.00	15.84	15.18
Financial Hedge	**(3.61)**	(3.47)	(2.92)	(2.22)	(5.95)	(0.77)	(0.58)	(0.75)
Netback including hedge	**12.30**	11.27	12.30	13.21	12.57	14.23	15.26	14.43
Ecuador Oil *(US$/bbl)*								
Price, net of royalties	**24.21**	23.57	22.13	22.31	30.86	24.02	22.82	21.11
Production and mineral taxes	**1.47**	1.06	0.45	1.11	4.27	1.57	1.49	0.72
Transportation and selling	**2.56**	2.81	2.36	2.41	2.35	1.99	2.47	1.56
Operating expenses	**4.84**	4.62	4.33	5.63	5.09	5.35	4.12	5.13
Netback excluding hedge	**15.34**	15.08	14.99	13.16	19.15	15.11	14.74	13.70
Financial Hedge	**–**	–	–	–	–	–	–	(0.03)
Netback including hedge	**15.34**	15.08	14.99	13.16	19.15	15.11	14.74	13.67
United Kingdom Oil *(US$/bbl)*								
Price, net of royalties	**28.11**	27.05	27.92	27.17	30.61	25.73	27.07	25.92
Transportation and selling	**1.97**	1.70	1.98	1.86	2.45	1.53	1.92	1.62
Operating expenses	**5.09**	6.23	6.55	4.69	2.92	7.07	3.65	2.01
Netback excluding hedge	**21.05**	19.12	19.39	20.62	25.24	17.13	21.50	22.29
Financial Hedge	**–**	–	–	–	–	–	–	–
Netback including hedge	**21.05**	19.12	19.39	20.62	25.24	17.13	21.50	22.29
Total Liquids – All Countries *(US$/bbl)*								
Price, net of royalties	**23.25**	22.51	21.22	22.93	26.89	21.51	21.95	20.70
Production and mineral taxes	**0.45**	0.59	(0.35)	0.58	1.02	0.66	0.50	0.25
Transportation and selling	**1.47**	1.74	0.95	1.51	1.64	1.10	1.18	0.76
Operating expenses	**4.93**	4.75	5.01	5.22	4.77	4.18	4.16	4.21
Netback excluding hedge	**16.40**	15.43	15.61	15.62	19.46	15.57	16.11	15.48
Financial Hedge	**(2.54)**	(2.15)	(2.18)	(1.61)	(4.45)	(0.57)	(0.42)	(0.53)
Netback including hedge	**13.86**	13.28	13.43	14.01	15.01	15.00	15.69	14.95

* Q1 2002 has been excluded as it represents activity prior to the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd.

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Average Royalty Rates

(excluding impact of financial hedging)	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002* Q4	2002* Q3	2002* Q2
Produced Gas								
Canada	**12.9%**	12.2%	12.9%	14.2%	12.4%	13.3%	10.4%	11.8%
United States	**20.0%**	19.5%	20.2%	20.1%	20.5%	21.1%	23.1%	19.4%
Crude Oil								
Canada and United States	**10.3%**	9.7%	9.0%	10.7%	11.8%	10.8%	11.7%	11.6%
Ecuador	**25.6%**	25.4%	25.7%	24.9%	26.9%	28.1%	28.5%	28.5%
Natural Gas Liquids								
Canada	**17.5%**	14.7%	16.6%	18.0%	20.2%	16.4%	13.8%	15.6%
United States	**17.6%**	17.5%	17.0%	17.3%	18.5%	13.3%	12.0%	10.5%
Total Upstream	**14.5%**	14.4%	14.2%	15.1%	14.4%	14.8%	13.8%	13.9%

* Q1 2002 has been excluded as it represents activity prior to the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd.

2003 Wells Drilled – Exploration

	Gas Gross	Gas Net	Oil Gross	Oil Net	Dry & Abandoned Gross	Dry & Abandoned Net	**Total Working Interest Gross**	**Total Working Interest Net**	Royalty Interest Gross
Canada	532	511	51	31	35	28	**618**	**570**	153
United States	40	35	7	2	4	2	**51**	**39**	–
Ecuador	–	–	3	2	–	–	**3**	**2**	–
United Kingdom	–	–	2	1	5	3	**7**	**4**	–
Other	1	–	–	–	3	1	**4**	**1**	–
Total	573	546	63	36	47	34	**683**	**616**	153
Success Rate *(%)*							**93%**	**94%**	

2003 Wells Drilled – Development

	Gas Gross	Gas Net	Oil Gross	Oil Net	Dry & Abandoned Gross	Dry & Abandoned Net	**Total Working Interest Gross**	**Total Working Interest Net**	Royalty Interest Gross
Canada	3,964	3,901	756	650	24	18	**4,744**	**4,569**	1,347
United States	426	401	–	–	1	1	**427**	**402**	–
Ecuador	–	–	53	39	6	6	**59**	**45**	–
United Kingdom	–	–	3	–	–	–	**3**	**–**	–
Total	4,390	4,302	812	689	31	25	**5,233**	**5,016**	1,347
Success Rate *(%)*							**99%**	**100%**	
TOTAL WELLS	**4,963**	**4,848**	**875**	**725**	**78**	**59**	**5,916**	**5,632**	**1,500**
Success Rate *(%)*							**99%**	**99%**	

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Summary of Working Interest Land Holdings

As at December 31, 2003 (thousands of acres)

			Developed		Undeveloped		Total	
			Gross	Net	Gross	Net	Gross	Net
Canada	Alberta	– Fee	2,566	2,422	2,746	2,717	**5,312**	**5,139**
		– Crown	3,710	3,149	6,986	5,978	**10,696**	**9,127**
		– Freehold	197	63	554	279	**751**	**342**
			6,473	5,634	10,286	8,974	**16,759**	**14,608**
	British Columbia	– Fee	–	–	7	7	**7**	**7**
		– Crown	656	549	4,850	4,031	**5,506**	**4,580**
			656	549	4,857	4,038	**5,513**	**4,587**
	Saskatchewan	– Fee	12	10	481	467	**493**	**477**
		– Crown	345	214	1,326	1,128	**1,671**	**1,342**
		– Freehold	73	37	235	157	**308**	**194**
			430	261	2,042	1,752	**2,472**	**2,013**
	Manitoba	– Fee	–	–	271	266	**271**	**266**
		– Crown	–	–	30	30	**30**	**30**
		– Freehold	–	–	23	23	**23**	**23**
			–	–	324	319	**324**	**319**
	Newfoundland & Labrador	– Crown	–	–	4,294	2,781	**4,294**	**2,781**
	Nova Scotia	– Crown	–	–	4,404	2,988	**4,404**	**2,988**
	Northwest Territories	– Crown	–	–	1,019	459	**1,019**	**459**
	Nunavut	– Crown	–	–	817	26	**817**	**26**
	Beaufort	– Crown	–	–	126	4	**126**	**4**
Total Canada			**7,559**	**6,444**	**28,169**	**21,341**	**35,728**	**27,785**
United States	Colorado	– Federal/State Lands	173	144	439	381	**612**	**525**
		– Freehold	84	70	215	186	**299**	**256**
		– Fee	4	3	9	8	**13**	**11**
			261	217	663	575	**924**	**792**
	Wyoming	– Federal/State Lands	58	23	640	463	**698**	**486**
		– Freehold	4	2	46	33	**50**	**35**
			62	25	686	496	**748**	**521**
	Alaska	– Federal/State Lands	–	–	1,794	802	**1,794**	**802**
	Gulf of Mexico	– Federal/State Lands	–	–	1,511	663	**1,511**	**663**
	Other	– Federal/State Lands	10	7	320	270	**330**	**277**
		– Freehold	18	12	259	126	**277**	**138**
			28	19	579	396	**607**	**415**
Total United States			**351**	**261**	**5,233**	**2,932**	**5,584**	**3,193**
Ecuador			141	80	1,258	811	**1,399**	**891**
United Kingdom			44	12	1,822	744	**1,866**	**756**
Chad			–	–	108,536	54,268	**108,536**	**54,268**
Oman			–	–	9,606	9,606	**9,606**	**9,606**
Australia			–	–	18,396	6,512	**18,396**	**6,512**
Qatar			–	–	2,758	2,758	**2,758**	**2,758**
Ghana			–	–	3,677	1,471	**3,677**	**1,471**
Yemen			–	–	1,879	987	**1,879**	**987**
Greenland			–	–	985	862	**985**	**862**
Brazil			–	–	161	108	**161**	**108**
Bahrain			–	–	97	48	**97**	**48**
Azerbaijan			–	–	346	17	**346**	**17**
Total International			**185**	**92**	**149,521**	**78,192**	**149,706**	**78,284**
Total			**8,095**	**6,797**	**182,923**	**102,465**	**191,018**	**109,262**

Notes:
(1) This table excludes approximately 3.6 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.
(2) Fee lands are those in which EnCana owns mineral rights and in which it retains a working interest.
(3) Crown/Federal/State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.
(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.
(5) Gross acres are the total area of properties in which EnCana has an interest.
(6) Net acres are the sum of EnCana's fractional interest in gross acres.

CORPORATE INFORMATION

CORPORATE AND DIVISIONAL OFFICERS

Gwyn Morgan
President & Chief Executive Officer

Randall K. Eresman
Executive Vice-President &
Chief Operating Officer
President, Upstream Division

Roger J. Biemans
Executive Vice-President
President, USA Region

Alan Booth
Managing Director, UK Region

John K. Brannan
Managing Director, International New Ventures Exploration

Michael M. Graham
President, Canadian Foothills & Frontier Region

Donald T. Swystun
President, Ecuador Region

Jeff E. Wojahn
President, Canadian Plains Region

Brian C. Ferguson
Executive Vice-President,
Corporate Development

Kerry D. Dyte
General Counsel &
Corporate Secretary

R. William Oliver
Executive Vice-President
President, Midstream & Marketing Division

Gerard J. Protti
Executive Vice-President,
Corporate Relations

Drude Rimell
Executive Vice-President,
Corporate Services

John D. Watson
Executive Vice-President &
Chief Financial Officer

Thomas G. Hinton
Treasurer

Ronald H. Westcott
Comptroller

BOARD OF DIRECTORS

Michael N. Chernoff [2, 6]
West Vancouver, British Columbia

Ralph S. Cunningham [2, 3]
Montgomery, Texas

Patrick D. Daniel [1, 5]
Calgary, Alberta

Ian W. Delaney [3, 4]
Toronto, Ontario

William R. Fatt [1]
Toronto, Ontario

Michael A. Grandin [3, 5, 6]
Calgary, Alberta

Barry W. Harrison [1, 4]
Calgary, Alberta

Richard F. Haskayne, O.C. [3, 4]
Calgary, Alberta

Dale A. Lucas [1, 5]
Calgary, Alberta

Ken F. McCready [2, 5]
Calgary, Alberta

Gwyn Morgan
Calgary, Alberta

Valerie A.A. Nielsen [2, 6]
Calgary, Alberta

David P. O'Brien [7]
Calgary, Alberta

Jane L. Peverett [1]
West Vancouver, British Columbia

Dennis A. Sharp [2, 4]
Calgary, Alberta

James M. Stanford [1, 3, 6]
Calgary, Alberta

1 Audit Committee
2 Corporate Responsibility, Environment, Health and Safety Committee
3 Human Resources and Compensation Committee
4 Nominating and Corporate Governance Committee
5 Pension Committee
6 Reserves Committee
7 Chairman of the Board, Chairman of Nominating and Corporate Governance Committee, and ex officio member of all other Board Committees.

ENCANA HEAD OFFICE

1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
Website: www.encana.com

TRANSFER AGENTS & REGISTRAR

Common Shares
CIBC Mellon Trust Company
Calgary, Montreal, Toronto, and
Mellon Investor Services LLC
New York

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline 416-643-5500 or toll-free throughout North America at 1-800-387-0825, or via facsimile at 416-643-5501.

Mailing Address
CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9

Internet Addresses
inquiries@cibcmellon.com (Email)
www.cibcmellon.com (Website)

TRUSTEE & REGISTRARS

CIBC Mellon Trust Company
Canadian Medium Term Notes
8.75% Debentures
7.00% Preferred Securities
Calgary, Toronto

Computershare Trust Company of Canada
8.50% Preferred Securities
Calgary, Toronto

The Bank of New York
4.750% Senior Notes
7.375% Senior Notes
7.650% Senior Notes
8.125% Senior Notes
9.500% Preferred Securities
New York

The Bank of Nova Scotia Trust Company of New York
6.30% Senior Notes
7.20% Senior Notes
New York

AUDITORS

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVE EVALUATORS

Onshore North America
Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Offshore & International
DeGolyer and MacNaughton
Dallas, Texas

Ryder Scott Company
Calgary, Alberta
Houston, Texas

STOCK EXCHANGES

Common Shares (ECA)
Toronto Stock Exchange
New York Stock Exchange

7.00% Preferred Securities
Toronto Stock Exchange (ECA.DB)

8.50% Preferred Securities
Toronto Stock Exchange (ECA.PR.A)

9.50% Preferred Securities
New York Stock Exchange (ECAPRA)

PRINCIPAL SUBSIDIARIES & PARTNERSHIPS (1)

	Percent Owned (2)
Alenco Inc.	100
EnCana Marketing (USA) Inc.	100
EnCana Oil & Gas (USA) Inc.	100
EnCana West Ltd.	100
EnCana Midstream & Marketing (3)	100
EnCana Oil & Gas Partnership	100

(1) Entities whose total assets exceed 10 percent of total consolidated assets of EnCana Corporation or whose revenues exceed 10 percent of the total consolidated revenues of the Corporation for the year ended December 31, 2003.
(2) Includes indirect ownership.
(3) Formerly EnCana Resources.

The above is not a complete list of all of the subsidiaries and partnerships of EnCana Corporation.

INVESTOR INFORMATION

Annual Meeting
Shareholders of EnCana Corporation are invited to attend the Annual and Special Meeting being held on Wednesday, April 28, 2004 at 10:30 a.m., local time, at the Hyatt Regency Calgary, 700 Centre Street S.E., Calgary, Alberta. Those unable to do so are asked to sign and return the form of proxy mailed to them.

Annual Information Form (Form 40-F)
EnCana's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, EnCana's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

Shareholder Account Matters
To change your address, transfer shares, eliminate duplicate mailings, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, etc., please contact CIBC Mellon Trust Company.

EnCana Website
EnCana's website contains a variety of corporate and investor information including, among other information, the following:

- Current stock prices
- Annual and Interim Reports
- Information Circular
- News releases
- Investor presentations
- Dividend information
- Shareholder support information

Website: www.encana.com

Additional information, including copies of the 2003 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations,
Corporate Development
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: (403) 645-3550
Visit our website: www.encana.com

Investor inquiries should be directed to:

Sheila McIntosh
Vice-President, Investor Relations
(403) 645-2194
sheila.mcintosh@encana.com

Greg Kist
Manager, Investor Relations
(403) 645-4737
greg.kist@encana.com

Tracy Weeks
Manager, Investor Relations
(403) 645-2007
tracy.weeks@encana.com

Financial and business media inquiries should be directed to:

Alan Boras
Manager, Media Relations
(403) 645-4747
alan.boras@encana.com

General media inquiries should be directed to:

Florence Murphy
Vice-President,
Public & Community Relations
(403) 645-4748
florence.murphy@encana.com

Abbreviations

bbls	barrels
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrel of oil equivalent
Btu	British thermal unit
CAPP	Canadian Association of Petroleum Producers
CO_2E	carbon dioxide equivalent
GJ	gigajoule
km	kilometre(s)
kW	kilowatt
kWh	kilowatt hour
m	metre(s)
m^3OE	cubic metres oil equivalent
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MM	million
MMbbls	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfe	million cubic feet equivalent
MT	megatonnes
NGLs	natural gas liquids
PCI	product carbon intensity
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent

Growth & Returns Matter

ENCANA CORPORATION

Investor relations inquiries should be directed to:

Sheila McIntosh
Vice-President,
Investor Relations
(403) 645-2194

Greg Kist
Manager, Investor Relations
(403) 645-4737

Tracy Weeks
Manager, Investor Relations
(403) 645-2007

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Manager, Media Relations
(403) 645-4747

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Florence Murphy
Vice-President,
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