EnCana Corporation **2005** Annual Report

energy for people

2005 Annual Report

Delivering On Our Potential

Cover photo Coalbed methane well site, Rockyford, Alberta

Photo this page Top-drive rig, East Texas

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" or forward-looking information 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 or information. See page 60 for a more detailed advisory.

For convenience, references in this Annual Report to "EnCana", the "Company", the "company", "we", "us", "our" and similar references 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 32, 34 and 50 and the advisory found on pages 60-62 of this Annual Report.

Financial Highlights

US$ millions, except per share amounts	2005	2004	% Change
Revenues, net of royalties	14,266	10,259	39
Cash Flow [1]	7,426	4,980	49
Per Share – diluted	8.35	5.32	57
Net Earnings	3,426	3,513	-2
Per Share – diluted	3.85	3.75	3
Operating Earnings [2]	3,241	1,976	64
Per Share – diluted	3.64	2.11	73
Net Capital Investment	4,097	4,206	
Shares Purchased (millions of shares)	55.2	40.0	
Average Price	34.85	25.12	
Net Debt-to-Capitalization (%)	33	33	
Net Debt-to-EBITDA (times) [3]	1.1	1.4	
Net Debt-to-Proved Developed Reserves ($/Mcfe) [4]	0.80	0.79	
Return on Capital Employed (%)	17	20	
Return on Common Equity (%)	23	27	

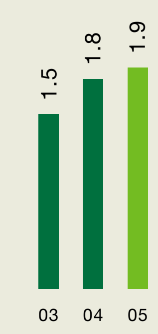
Operating Highlights

After Royalties	2005	2004	% Change
Continuing Operations – North America			
Natural Gas Sales (MMcf/d)			
Canada	2,132	2,099	2
U.S.A.	1,095	869	26
Total Natural Gas Sales (MMcf/d)	3,227	2,968	9
Oil and NGLs Sales (bbls/d)	156,000	166,417	-6
Total Sales Continuing Operations (MMcfe/d)	4,163	3,966	5
Discontinued Operations			
U.K. Total Sales (MMcfe/d)	–	126	
Ecuador Oil Sales (bbls/d)	71,065	77,993	
Total Sales Discontinued Operations (MMcfe/d)	426	594	
Total Sales (MMcfe/d)	4,589	4,560	1
Net Reserves Additions (Bcfe) [5]	4,542	3,163	
Production Replacement (%) [5]	271	189	
Reserve Replacement Cost ($/Mcfe) [5]	0.91	1.40	
Finding & Development Cost ($/Mcfe) [5]	1.29	1.44	
Reserve Life Index (years) [5]	11.0	9.3	
Year-end Reserves (Bcfe) [5]	18,507	15,643	18
Unbooked Resource Potential (Bcfe) [6]		24,400	

(1) As defined on page 32.
(2) As defined on page 34.
(3) As defined on page 50.
(4) 2004 before bitumen revision as discussed on page 109.
(5) Proved reserves only. 2004 before bitumen revision as discussed on page 109.
(6) As defined on page 61. 2004 number was released April 2005.

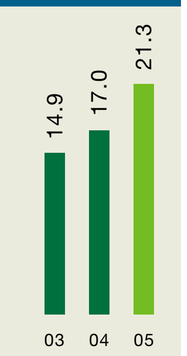
Strong Total Sales Growth

13% – compound annual growth rate per share



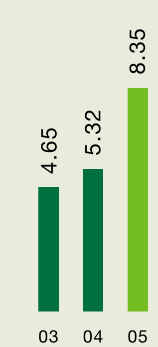
Consistent Reserves Growth

19% – compound annual growth rate per share



Record Cash Flow

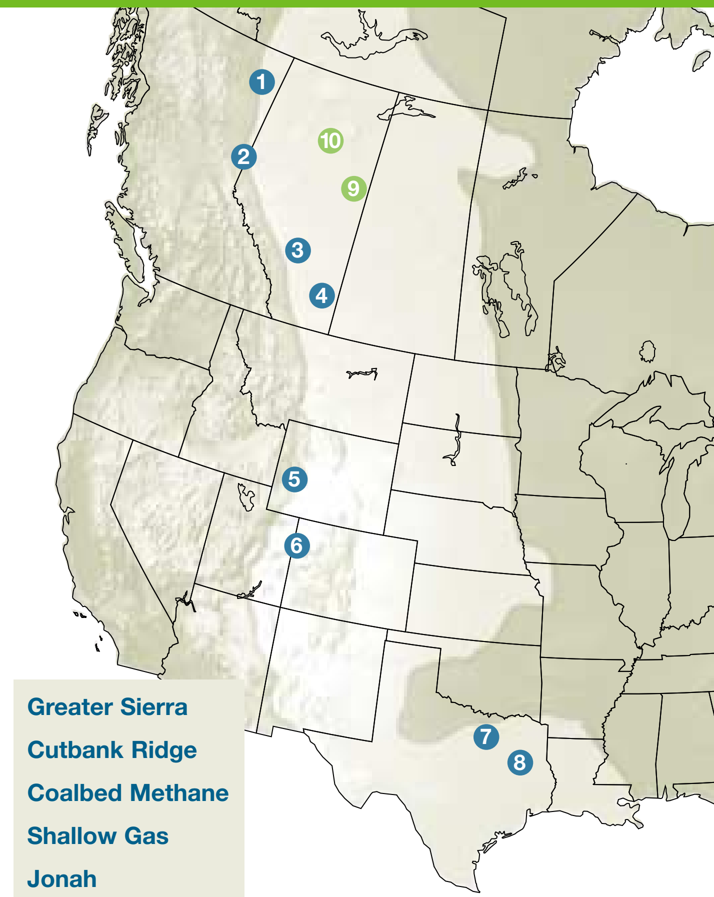
34% – compound annual growth rate per share



The Unconventional Fairway

EnCana has assembled a vast land position across North America's unconventional fairway, home to the company's 10 key resource plays.

North America's interior, the north-south expanse of the plains and grasslands running from the Gulf of Mexico to the Arctic, was not always a vast dry prairie or high plateau. Illustrated by the light green in the map at the right, a massive seaway once bisected the continent. Over a 25-million-year period during the Cretaceous Period and ending about 65 million years ago, rivers and rainwater washed sediments downstream from the western highlands – today's Rocky Mountains – to settle in a series of enormous sedimentary basins. With time and climate changes, shorelines migrated across this shallow sea, rivers cut new courses and enormous tectonic events deposited rocks, silt and sand rich with the plants, sea life and vegetation that formed a storehouse of deeply buried organic material. Layer upon layer of overburden generated massive pressures. In combination with geothermal heat extending over millions of years, these forces created hydrocarbons, the natural gas and oil that now fuel the Earth. Over more than three decades of operations, EnCana and its predecessor companies have assembled a vast land position across this unconventional fairway, home to the company's 10 key resource plays. From northeast British Columbia to east Texas, EnCana is profitably tapping and unlocking huge deposits of natural gas and bitumen on these resource play lands through the application of innovative technology, manufacturing methodology and unconventional thinking.



1 Greater Sierra
2 Cutbank Ridge
3 Coalbed Methane
4 Shallow Gas
5 Jonah
6 Piceance
7 Fort Worth
8 East Texas
9 Foster Creek
10 Pelican Lake

Natural Gas
Oil

Why **invest** in EnCana?

EnCana is a leading North American resource play company **focused on natural gas and in-situ oilsands.** The company's primary goal is to **optimize long-term growth of net asset value per share** through disciplined capital investment in the development of its vast unconventional resources.

Four fundamental characteristics illustrate why EnCana has confidence in the strength of its resource play potential:

- An extensive drilling inventory
  37,000 well locations
- Strong production and reserves growth
  Forecasting average annual 10% per share sales growth
- Robust project returns
  Targeting greater than 15% risk-adjusted internal rate of return
- Significant value upside
  In-situ oilsands development
  High impact exploration and portfolio management

CEO's Message

EnCana is an **industry leader** in the development of **unconventional reservoirs.**

Tank farm facility, Fort Worth, Texas

Our Strategy

Disciplined investment in developing our extensive inventory of resource plays to deliver predictable and profitable sales and reserves growth and increase the net asset value of every EnCana share.

Randy Eresman
President &
Chief Executive Officer

Delivering On Our Potential

It is a privilege to write my inaugural letter to shareholders shortly after assuming my new role as President & Chief Executive Officer and in the wake of such a dynamic and vibrant year for our industry and EnCana. The theme of our 2005 annual report is Delivering On Our Potential, and EnCana's resource potential is enormous – proved reserves of 11.8 trillion cubic feet of natural gas and 1.1 billion barrels of oil, plus unbooked resource potential estimated at 24 trillion cubic feet of gas equivalent. It is upon this resource foundation that we plan to grow annual sales at an average of 10 percent per share for years ahead. In this report, we discuss our achievements, explain EnCana's potential, and describe how we plan to deliver industry-leading performance and execution excellence in our natural gas and in-situ oilsands businesses. As always, our overarching goal is clear – building the net asset value of every EnCana share.

A Year of Contrasting Extremes

The year 2005 was filled with contrasting extremes – tremendous prices and one of the toughest operating environments ever. Robust world economic growth drove natural gas and oil prices to record levels. Demand for oilfield equipment and services skyrocketed, stoking industry inflation by as much as 30 percent. Devastating North American weather – a pair of massive hurricanes and record rainfall in Western Canada – took out Gulf of Mexico production and halted Canadian drilling crews in their tracks, further choking off supply and again driving up prices for gas, oil, compressors, steel, drill pipe, rigs, workers and construction. The prices we benefited from also fuelled inflation in our own industry. Everything energy cost more.

Sustained Performance During Turbulent Times

Through all the operational challenges, the strength and stability of our resource play strategy endured as EnCana achieved strong organic growth in 2005. Our natural gas sales increased 8 percent. Oil and natural gas liquids sales decreased 13 percent following the sales of some conventional production. In recent years, we have been shifting our oil focus towards growing our in-situ oilsands production, which increased more than 40 percent from the start of 2005. Total gas and liquids sales grew more than 6 percent per share. In the past three years, annual sales per share have increased an average of 13 percent. In 2005, our proved reserves grew 18 percent to 18.5 trillion cubic feet equivalent, generating a production replacement of 271 percent. These reserves were added at a very competitive finding and development cost of $1.29 per thousand cubic feet equivalent. With our 2005 netbacks averaging about $5.21 per thousand cubic feet equivalent, we achieved a recycle ratio of more than 4 times.

Through the year, we continued to sharpen our focus on gas and oil resource plays through divestitures of conventional assets, such as Ecuador, the Gulf of Mexico, Western Canada conventional oil production, a high-impact oil discovery offshore Brazil and our natural gas liquids business. Since our creation in 2002, EnCana has divested more than $11 billion in non-resource play assets, and we expect to complete the sale of another $1.8 billion of assets in the first half of this year.

Enormous Oilsands Potential

Our vast oilsands are at an early stage of development and we believe they hold enormous value that has yet to be realized. Late in 2005, we announced that we have the potential to increase in-situ oilsands production tenfold over the next decade, to 500,000 barrels per day by 2015. With development rights to 1.2 million acres capable of delivering bitumen from steam-assisted gravity drainage projects, EnCana is one of the largest holders of oilsands lands. Engineering evaluations indicate our recoverable resources are estimated at between 5 billion and 10 billion barrels of bitumen, and our lands contain an estimated 40 billion barrels of oil in place. As part of our expansion plans, EnCana is advancing discussions with a variety of oil companies – including major multinationals, integrated producers and national oil companies – for a potential partnership to upgrade, refine and market the company's bitumen production. This market integration initiative is expected to enable EnCana to participate in low-cost market development solutions that could expand the company's business beyond being a pure bitumen producer. Our in-situ oilsands lands were producing more than 50,000 barrels per day at the end of 2005, and current expansion work is expected to take productive capacity to about 70,000 barrels per day by year-end 2006.

Through all of the operational challenges, the **strength and stability** of our resource play strategy endured as EnCana achieved strong organic growth in 2005.

Strong Financial Performance

Robust pricing and our healthy sales growth generated strong financial performance in 2005. Cash flow per share increased 57 percent, operating earnings per share rose 73 percent and net earnings per share were up 3 percent. Return on capital employed was 17 percent and the company reinvested $3.1 billion from asset sales to lower debt and reduce shares outstanding by 4.5 percent under our Normal Course Issuer Bid. In May, EnCana shares split two-for-one and, in June, EnCana's annual dividend was increased by 50 percent to 30 cents per share, on a post-split basis. During 2005, EnCana shareholders received a total shareholder return of 55 percent. Over the past three years, total shareholder return was more than 120 percent for Canadian dollar shares and close to 200 percent for U.S. dollar shares, which is comparatively higher due to the appreciation of the Canadian dollar.

Tackling the Challenges

As I mentioned, last year was one of the toughest operating environments we have faced. Record activity levels and bad weather combined to create a stretched service sector, high inflation, significant delays and inefficiency in execution. In other years when rain temporarily sidetracked our operations, we were able to make up for lost time. But last year, given the tightness of resources in the service sector, there was little capacity to ramp up when the skies cleared. Weather delays and a shortage of field services left our field crews idle for up to three months, which meant that we drilled about 80 percent of our planned gas wells. Consequently, our natural gas sales levels in 2005 ran slightly lower than expected. This production is not lost; it is simply delayed. The tight oilfield service market fuelled inflation at EnCana of about 15 percent, prompting a rise in capital spending and operating costs. While we faced higher costs, we also benefited from higher prices.

Adding Rigs, Managing Costs

Moving into 2006 and beyond, EnCana is taking many steps to manage costs and build capacity for continued growth. One of our largest initiatives is the negotiation of long-term drilling contracts that will see about 50 to 60 new fit-for-purpose rigs added to our operations. These high-efficiency rigs are safer and drill faster, saving money and bringing production on-stream quicker. By the end of 2006, we expect to be operating about half of our drilling fleet under long-term contracts. The fleet averages about 120 rigs throughout the year. Across our operations, we have negotiated volume discounts with a variety of suppliers, buying in bulk such items as drill pipe, nitrogen, fuel, wellheads and completion and fracturing services. Through several long-term procurement contracts, EnCana expects to continue bringing efficiencies to its supply chain and capturing tens of millions of dollars in savings each year. With inflationary pressures expected to continue at a high level again this year, we decided to reduce 2006 drilling in areas where costs have increased the most. We trimmed our planned 2006 upstream capital investment by about $300 million, or 5 percent. With the anticipated proceeds from planned asset sales, we expect net capital investment of about $2.8 billion. Given the continued high activity levels for 2006, we expect our drilling and natural gas sales growth to be about the same as in 2005, about 4,700 wells and about 8 percent respectively. To help assure strong financial performance, we have about 93 percent of our 2006 forecast natural gas sales hedged with a combination of put options and fixed prices at an average floor price of NYMEX $7.30 per thousand cubic feet.

Resource Play Advantage – Unconventional Potential

Despite the dramatic and comparatively short-term events that impacted 2005, our focus remains on long-term value creation. With 17 million net acres of undeveloped land concentrated in the prime sedimentary basins flanking North America's Rocky Mountains, from the foothills of northeast British Columbia to the plains of Texas, EnCana is well positioned for the long term to continue supplying the most attractive energy market in the world – North America. Four fundamental characteristics help illustrate why our confidence in our resource play potential is stronger than ever.

- **Extensive drilling inventory.** On our current lands, we have identified about 37,000 well locations sitting over top of known gas and oil resources. At an annual drilling rate of approximately 5,000 wells per year, our inventory of development drilling is more than seven years.
- **High production and reserves growth.** We believe that our assets are capable of delivering annual sales growth averaging 10 percent per share. This forecast is based on two fundamental assets, our 18.5 trillion cubic feet of gas equivalent of proved reserves and our unbooked resource potential. An annual estimate of EnCana's unbooked resource potential is published in the second quarter of each year. The most recent, in April 2005, put the estimate at 19 trillion cubic feet of gas and 900 million barrels of oil and natural gas liquids, which is the equivalent of 24 trillion cubic feet of gas – a tremendous base for building long-term production and reserves growth.

- **Strong project returns.** Our focus on capital discipline means that, before we invest, development projects must be capable of delivering at least a 20 percent internal, risk-adjusted, after-tax rate of return, while our oilsands and exploration projects must return at least 15 percent. Many of our key resource plays are well above that. With strong prices in 2005, the average return on our upstream portfolio was more than 30 percent.
- **Huge value upside.** We believe that EnCana has huge value upside on a number of fronts, which of course includes our oilsands and our emerging natural gas resource plays. In addition, there is anticipated upside in our option-value exploration. By applying our core competencies to exploration and evaluation in select international locations, we are able to generate significant pre-development cash value. For example, in 2005, we made a significant oil discovery offshore Brazil, which we agreed to sell to an experienced offshore operator for $350 million, and we expect to record a gain of about $200 million. We also believe we have significant value creation potential through portfolio high-grading – a core competency we have repeatedly demonstrated over the last number of years. This is reflected in our reserve replacement cost, which was 91 cents per thousand cubic feet equivalent in 2005 and averaged $1.22 per thousand cubic feet equivalent over the past three years.

Youthful Potential

I encourage you to read pages 12 to 16 which explain the advantages of unconventional resources, how we define our enormous unbooked resource potential and how we have sharpened our focus on North America. Page 16 illustrates the resource play life cycle, which typically extends more than a quarter of a century. Our oldest play, shallow gas at Suffield, has operated since 1976 and, after 30 years, it is producing at record levels. Yet, by comparison, most of our key resource plays are just in the early stages of development. They each have many years of profitable growth ahead, forming the foundation for EnCana's promising future.

Long-term Value Creation Extends Beyond the Bottom Line

At EnCana, we know that our long-term success is dependent upon more than simply earning strong returns. Our long-term value creation is founded in the principles established in our Corporate Constitution. These principles guide all that we do – how we work with landowners and other external stakeholders, how we manage our environmental footprint, how we make community investments, and how we strive to make EnCana an employer of choice. Building and enhancing relationships helps us earn the social license to operate, a key to sustaining our financial success. In order to provide more comprehensive information on EnCana's corporate responsibility performance and in response to increasing interest in how we operate,

Our **overarching goal** is clear – building the net asset value of every EnCana share.

we are expanding our corporate responsibility reporting by publishing a stand-alone report, which will complement the extensive corporate responsibility information we maintain on our website at encana.com. I invite you to read our new Corporate Responsibility Report planned for publication in June.

Vision: Reliable, Accountable, Consistent

As always, our fundamental vision is rock solid: pursuit of industry leadership in capturing, developing and growing natural gas and in-situ oilsands resource plays, unlocking and delivering on our vast potential, growing the net asset value of every share, and reinforcing our reputation as reliable, accountable and consistent in all regards. EnCana is building upon all we have achieved to date, and continuing to create an industry-leading company in which people have confidence. On behalf of the Board of Directors, I want to express my appreciation to our employees who have put EnCana on a path that is well on the way to achieving this vision.

And of course, much of the creation and articulation of all that EnCana is and promises to be has resulted from the remarkable career of founding President & Chief Executive Officer Gwyn Morgan. Let me simply join the other voices in recognizing Gwyn's extraordinary company-building efforts. His inspirational vision, discipline, innovative competitiveness and independent initiative are leadership hallmarks for the energy business and beyond. On page 8 you will meet EnCana's new executive team, an experienced and talented team leading EnCana in the continuation of the company's tradition of long-term value creation.

Randy Eresman
President & Chief Executive Officer
March 6, 2006

Note from EnCana's founding Chief Executive Officer

Three decades ago, I joined one of EnCana's two founding companies and during the past four years have had the privilege of serving as the company's founding CEO. On January 1, 2006, a natural executive succession took place when Randy Eresman took office as EnCana's President & Chief Executive Officer.

Randy has worked at EnCana and one of its predecessor companies – Alberta Energy Company – for the past 25 years, which includes the past decade as a key member of our leadership team. He has been the architect of EnCana's industry-leading position in North American natural gas and in-situ oilsands resource plays. Throughout his career, he has demonstrated an extraordinary track record of value creation for shareholders.

In this my last year as an executive officer of EnCana, I want to acknowledge the contribution of two long-time members of our executive team. John Watson and I have worked together since we joined Alberta Energy at start-up in 1975 and he retires as one of Canada's most distinguished chief financial officers. Drude Rimell retires from Executive Vice-President, Corporate Services, where her knowledge, dedication and wise counsel were invaluable to me.

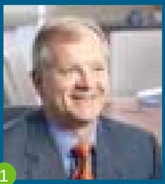
A key strength of EnCana is demonstrated by the fact that each of us is handing over our leadership roles to proven, capable people who have been very significant contributors to our company. It is with great pride that I express complete confidence that Randy and his team will build upon EnCana's clear competitive advantage, highly ethical reputation and history of success.

Gwyn Morgan
Executive Vice-Chairman

What EnCana Delivered in 2005

Grew total sales by 6% per share	Delivered strong growth despite difficult weather conditions and service sector capacity constraints.
Increased natural gas sales by 14% per share	Strong gas growth driven by an 18% year-over-year increase in production from key resource plays.
Replaced 271% of production	Net proved reserves additions were 4.5 Tcfe and proved reserves increased by 18% to 18.5 Tcfe.
Achieved F&D costs of $1.29/Mcfe	Strong finding & development performance derived from organic growth.
Purchased 55.2 million common shares for cancellation for $1.9 billion	The company renewed its Normal Course Issuer Bid in October 2005 that allows it to purchase an additional 10% of the public float of its common shares through to October 2006.
Improved financial strength	Maintained strong net debt-to-capitalization of 33% and reduced net debt-to-EBITDA from 1.4x to 1.1x.

Executive Team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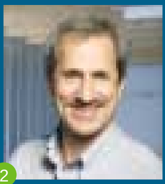
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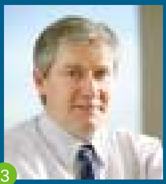
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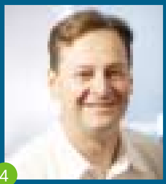
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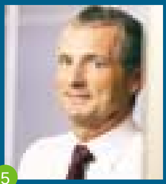
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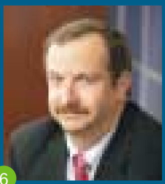
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1 **Brian Ferguson**
Executive Vice-President
& Chief Financial Officer

2 **Roger Biemans**
Executive Vice-President
President, Canadian Plains Region

3 **Mike Graham**
Executive Vice-President
President, Canadian Foothills Region

4 **Jeff Wojahn**
Executive Vice-President
President, USA Region

5 **Bill Oliver**
Executive Vice-President
President, Midstream & Marketing

6 **John Brannan**
Managing Director,
Frontier & International New Ventures

7 **Don Swystun**
Executive Vice-President,
Corporate Development

8 **Gerry Protti**
Executive Vice-President,
Corporate Relations

9 **Hayward Walls**
Executive Vice-President,
Corporate Services & Chief Information Officer

10 **Sherri Brillon**
Vice-President,
Strategic Planning & Portfolio Management

Operations

EnCana has developed the **expertise and technology** to unlock value from unconventional reservoirs.

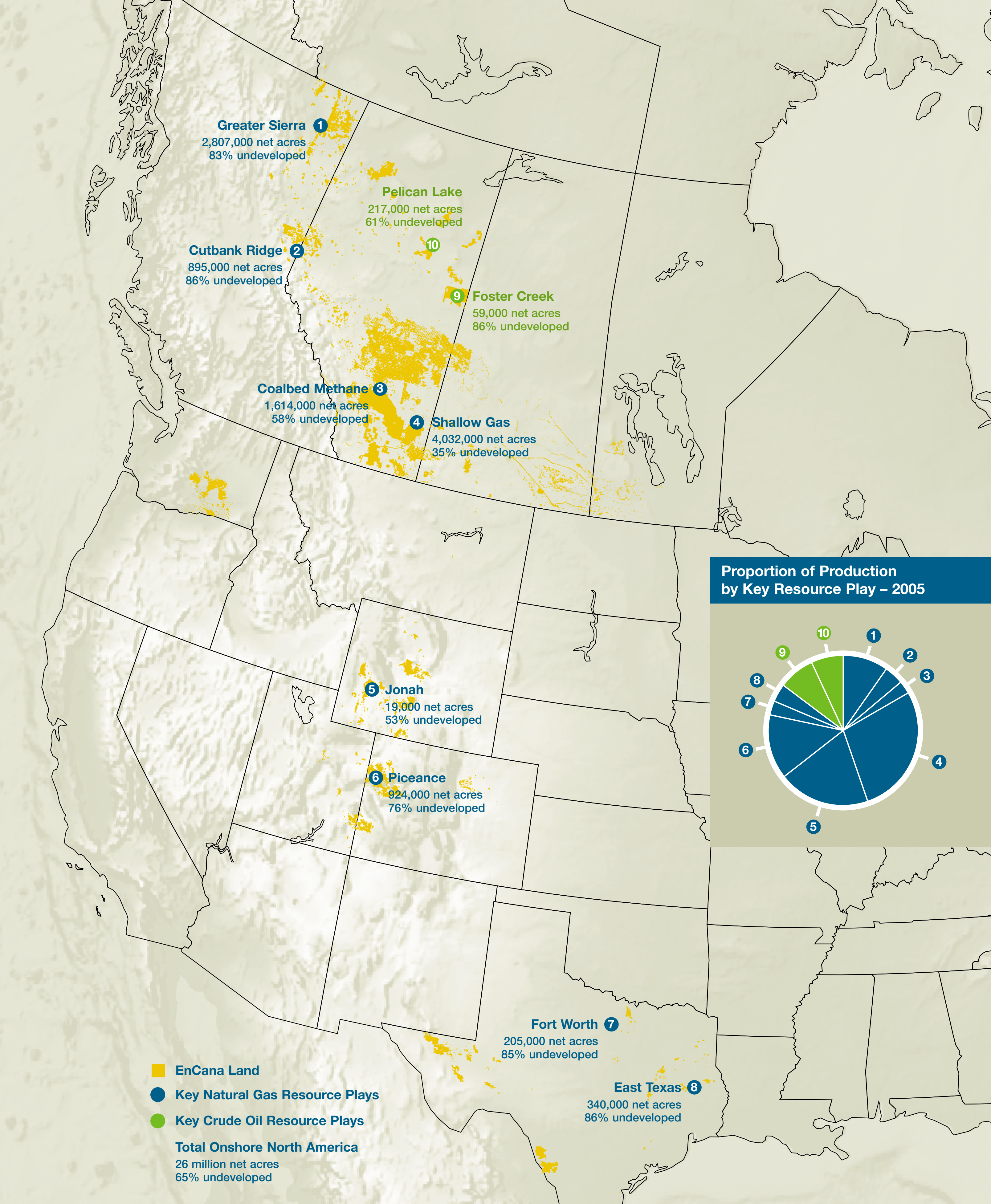
Fit-for-purpose drilling rig, Cutbank Ridge, British Columbia

EnCana's portfolio of long-life resource plays includes 10 key plays in Canada and the United States. Production from these **resource plays** has grown at a compound annual rate of 25 percent over the past three years.

Natural Gas	Production (MMcf/d) 2005	Production (MMcf/d) 2006F	Capital ($MM) 2005	Capital ($MM) 2006F	Wells drilled (net) 2005	Wells drilled (net) 2006F
1 Greater Sierra	219	225 - 235	417	340 - 350	164	150
2 Cutbank Ridge	92	160 - 165	510	500 - 520	135	115
3 Coalbed Methane	57	150 - 160	386	440 - 460	1,084	800
4 Shallow Gas	625	610 - 620	333	290 - 295	1,267	1,060
5 Jonah	435	510 - 530	300	500 - 530	104	210
6 Piceance	307	300 - 320	661	510 - 550	266	260
7 Fort Worth	70	90 - 110	170	220 - 260	59	105
8 East Texas	90	90 - 110	227	160 - 200	84	65
Subtotal – Gas	1,895	2,135 - 2,250	3,004	2,960 - 3,165	3,163	2,765

Crude Oil	Production (bbls/d) 2005	Production (bbls/d) 2006F	Capital ($MM) 2005	Capital ($MM) 2006F	Wells drilled (net) 2005	Wells drilled (net) 2006F
9 Foster Creek	29,019	40,000 - 42,000	306	260 - 270	39	33
10 Pelican Lake	25,752	25,000 - 26,000	95	55 - 65	52	–
Subtotal – Oil	54,771	65,000 - 68,000	401	315 - 335	91	33

Total	Production (MMcfe/d) 2005	Production (MMcfe/d) 2006F	Capital ($MM) 2005	Capital ($MM) 2006F	Wells drilled (net) 2005	Wells drilled (net) 2006F
Key Resource Plays	2,224	2,525 - 2,658	3,405	3,275 - 3,500	3,254	2,798


Greater Sierra 1
2,807,000 net acres
83% undeveloped
Pelican Lake
217,000 net acres
61% undeveloped
10
Cutbank Ridge 2
895,000 net acres
86% undeveloped
9 Foster Creek
59,000 net acres
86% undeveloped
Coalbed Methane 3
1,614,000 net acres
58% undeveloped
4 Shallow Gas
4,032,000 net acres
35% undeveloped
5 Jonah
19,000 net acres
53% undeveloped
6 Piceance
924,000 net acres
76% undeveloped
Fort Worth 7
205,000 net acres
85% undeveloped
East Texas 8
340,000 net acres
86% undeveloped
Proportion of Production by Key Resource Play – 2005
10
1
2
9
3
8
7
6
4
5
EnCana Land
Key Natural Gas Resource Plays
Key Crude Oil Resource Plays
Total Onshore North America
26 million net acres
65% undeveloped

Resource Play Advantage

30 years experience developing **unconventional reservoirs** • unparalleled onshore North American land position of 26 million net acres – including 17 million net undeveloped • significant unbooked resource potential.

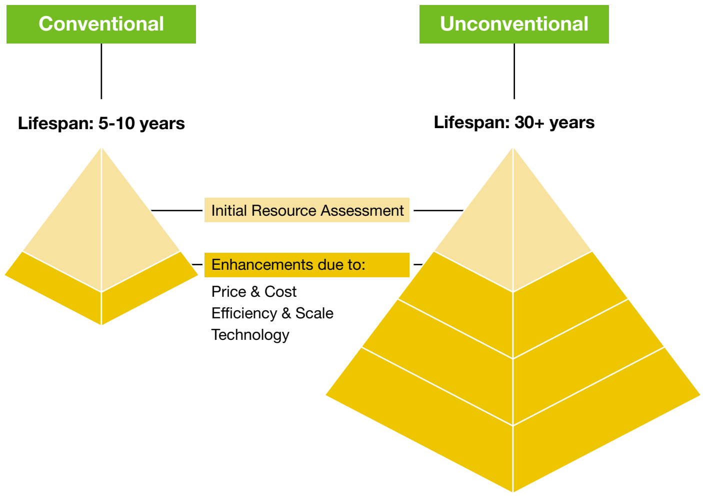
EnCana's Competitive Advantage

EnCana's geographic focus is North America, which has among the highest known concentrations of unconventional natural gas and oilsands resources in the world. Compared to conventional plays, these long-life reservoirs typically have lower than average long-term decline rates and lower geological and commercial development risk. EnCana's people have the skills, expertise and technology to maximize the value from its 26 million net acres of North American onshore lands, 17 million of which are undeveloped. EnCana has currently identified 37,000 future drilling locations and more than 24 trillion cubic feet of gas equivalent of unbooked resource potential. This is why EnCana has the confidence to forecast continued profitable sales growth averaging 10 percent per share per year.

Conventional versus Unconventional Thinking

EnCana's geological focus is on resource plays. These are large continuous accumulations of hydrocarbons that are capable of delivering profitable production for decades through the application of advanced technology and large manufacturing-like development programs that capture economies of scale. The diagram to the right compares the potential of a conventional gas reservoir to that of an unconventional reservoir. Original assessment of recoverable reserves from conventional reservoirs typically identifies the majority of the resource in place, with very limited upside potential. These reservoirs are typically produced over a five- to 10-year lifespan.

On the other hand, original assessments of unconventional gas reservoirs often show only a small percentage of what is ultimately recoverable. Unconventional development involves drilling numerous wells in a repeatable manner that captures economies of scale. These reservoirs are produced over 30 years or more. As a result, the company can take advantage of operational efficiencies and new technologies, developed over time, to reduce costs and increase recoveries. For example, at EnCana's Jonah resource play in Wyoming, the original estimate of gas in place, completed in 2000, was about 200 billion cubic feet per square mile. Five years later, improvements in technology and recovery methods have increased the estimate of gas in place to be between 350 to 400 billion cubic feet per square mile, almost double the original estimate. With this and similar experiences in its suite of resource plays, EnCana has confidence that it will be able to grow reserves, production and the net asset value of every share.



Unconventional Advantages

The large contiguous nature of unconventional plays allows EnCana to apply scale and technologies that increase recoveries and drive down costs over time.

Aerial view of coalbed methane drilling rig, Three Hills, Alberta

Defining Unbooked Resource Potential

EnCana defines unbooked resource potential (URP) as quantities of oil and natural gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

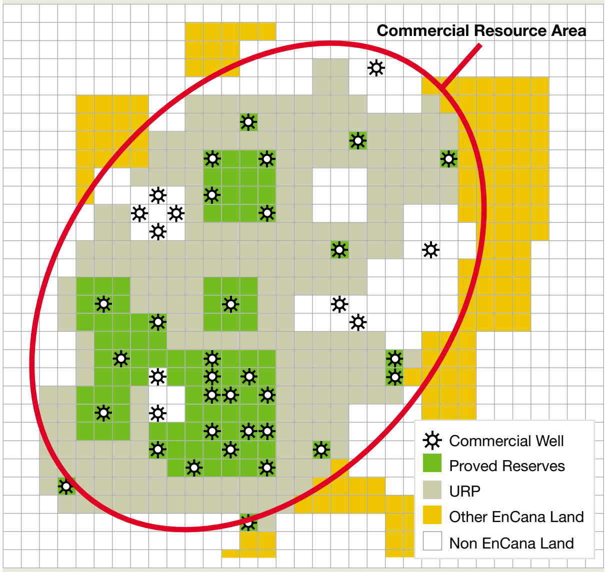
The diagram to the right is an example of a resource play map illustrating both proved reserves and URP. Resource plays typically cover large contiguous tracts of land with similar geological and reservoir characteristics. After identifying a resource play, EnCana captures the lands it believes contain the contiguous geological formations. Early in the development, a multidisciplinary team evaluates the size of the play by drilling wells at the outer edges of the play, and works to define its economic limit.

Independent qualified reserves evaluators provide proved reserves estimates at December 31 of each year in compliance with U.S. Securities and Exchange Commission regulatory requirements and practices. Lands assigned proved reserves appear in green on the diagram.

Drilling, well test and production performance results, coupled with EnCana's knowledge and experience often indicate that additional resources exist beyond the lands assigned proved reserves. These additional hydrocarbon resources, residing within the tested boundaries of the play that meet the company's technical and economic criteria, are classified as URP – natural gas and crude oil that the company's engineers believe may be moved into proved reserves and produced in the future. On the accompanying diagram, lands to which URP is attributed are coloured grey. As EnCana develops the resource play, the play size often expands while acquired knowledge and experience lead to improved operational efficiencies and the potential to increase the URP estimates.

Resource Opportunity

Resource plays cover large contiguous blocks of land with an expectation of similar geology throughout.



- Proved reserves are evaluated by independent qualified reserves evaluators.
- EnCana's knowledge and experience indicate that additional resources exist beyond the lands assigned proved reserves – Unbooked Resource Potential.

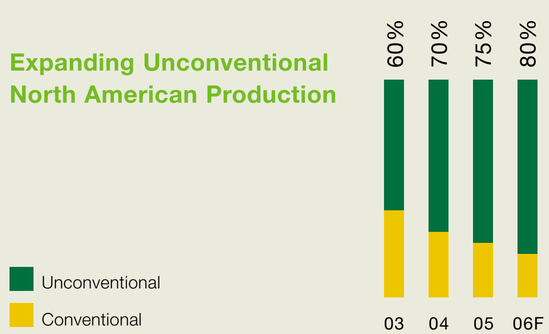
EnCana returns value directly to shareholders through **dividends and share purchases.**

Unconventionally Focused in North America

Since inception in April 2002, EnCana has steadily transitioned its asset base by selling conventional properties in North America and several international basins, while strategically adding to an already strong base of unconventional properties in North America. EnCana sold assets where it did not possess a strong competitive advantage or the expertise in development, such as offshore oil properties in the North Sea and the Gulf of Mexico. Instead it focused on acquiring properties where it could bring its expertise and technology to bear. This included the Tom Brown, Inc. acquisition in 2004, which expanded its land base in the Piceance and East Texas basins. To the end of 2005, sales of non-core international and North American conventional assets have generated more than $9.6 billion, while $5.3 billion has been invested in companies and properties that complement EnCana's North American unconventional focus. In 2005, the sharpened focus on the unconventional continued with the addition of several key assets, including approximately 330,000 total net acres in the west Texas shales and approximately 220,000 total net acres in the multi-layered formations of central Alberta.

EnCana's overall land position forms the platform from which the company can continue to grow for years to come.

Expanding Unconventional North American Production

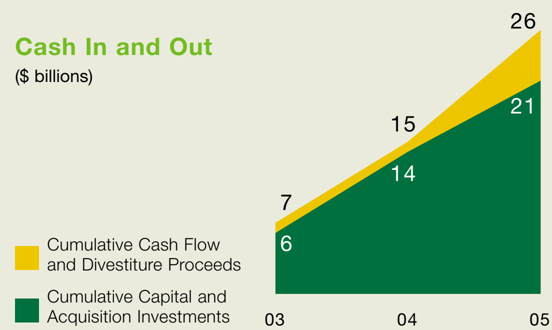


In 2006, the company expects that unconventional plays will represent approximately 80% of its production.

Cash In Captures Value; Cash Out Creates Value

EnCana's disciplined capital program manages four core components: cash flow from operations, proceeds from divestitures, drill-bit capital investment, and investments in asset acquisitions. Over the past three years, EnCana's cash in (cash flow from operations and proceeds from divestitures) has exceeded its cash out (drill bit capital investment and investments in asset acquisitions). This resulted in a significant surplus of about $5.2 billion – value that was largely returned to investors.

Cash In and Out
($ billions)



Over the past 3 years, cash in has exceeded cash out by more than $5 billion.

In 2005, the Board of Directors approved a 50 percent increase in EnCana's quarterly dividend to 7.5 cents per share. As well, EnCana purchased about 55.2 million of its shares for $1.9 billion. Since 2002, the company has purchased and cancelled approximately 143 million shares, reducing shares outstanding by 11 percent to approximately 855 million shares at the end of 2005. Fewer shares outstanding means that each share represents a greater piece of the company. In October 2005, EnCana renewed its Normal Course Issuer Bid, allowing the company to purchase an additional 10 percent of the public float of its common shares.

Key Resource Plays

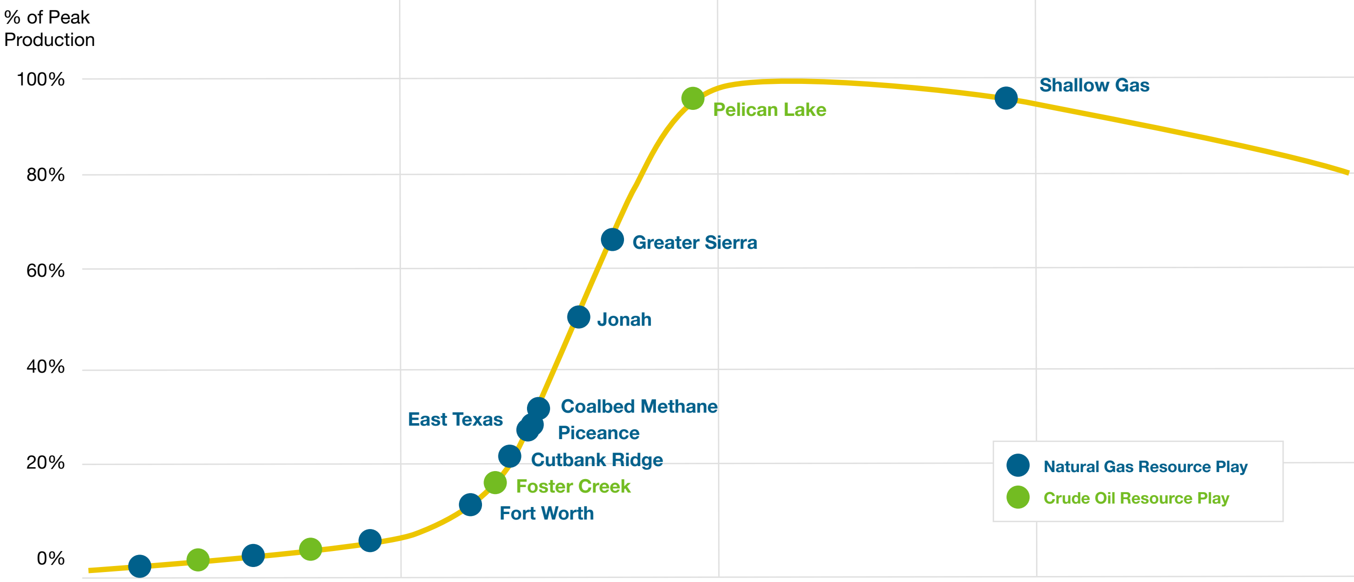
EnCana continues to build its **potential** through strategic land acquisitions.

EnCana operations in the prairies of Alberta

Resource Play Life Cycle

The majority of EnCana's **key gas resource plays** are still in the **early stages of development,** producing at less than one-third of their ultimate expected rates.

Exploration and Piloting	Primary Development	Maintenance	Decline
Assess the potential of the play; test and develop the reservoir. Begin technology application. This stage could last 1 to 5 years.	Drill wells and build infrastructure to grow resource play. Continue development with technology application. This stage could last 5 to 10 years.	Employ new technology and production techniques to maintain volumes. This stage could last 10 to 20 years.	Field is in decline. This stage could last 10 to 20 years.



Shallow Gas – Setting the Standard

Discovered 30 years ago, the shallow gas field at Suffield typifies the evolution of a resource play. When first assessed, Suffield's original gas in place was estimated at more than 1.5 trillion cubic feet. After three decades of relatively steady growth, production is only now hitting a plateau, with the field having delivered more than 2 trillion cubic feet, well in excess of the original estimate. EnCana has been able to profitably grow this play by applying new technologies, such as fit-for-purpose drilling rigs and more efficient fracturing and pipelining techniques. These initiatives minimized costs and improved field economics.

Key Resource Plays

1 Greater Sierra

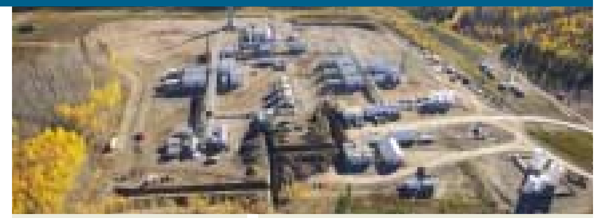
This natural gas play in northeast British Columbia focuses on the Devonian Jean Marie geological formation. EnCana has successfully developed this play primarily using underbalanced horizontal drilling techniques. The tight gas play benefits from the British Columbia government's recent royalty incentive program which targets unconventional resource development.

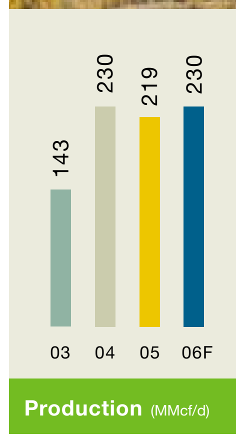
2005 Highlights

- Identified additional upper Devonian gas-charged formations for development.
- Increased rig utilization through year-round drilling, which improved safety performance and drilling costs.
- Initiated farm-outs to allow development of select lands outside of the core development area while maintaining exposure to successful exploration results.

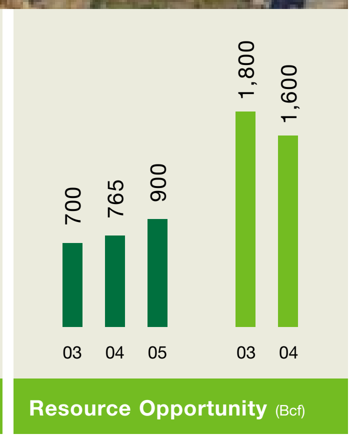
Outlook

- Grow production annually at 5% to 10%, targeting a peak of 350 MMcf/d.
- Explore upper Devonian dual prospect opportunities.
- Deploy new fit-for-purpose drilling rigs to improve efficiency by reducing drilling time and costs.
- Evaluate well locations with 3-D seismic.





06F Midpoint of guidance



Proved reserves

Unbooked resource potential

2 Cutbank Ridge

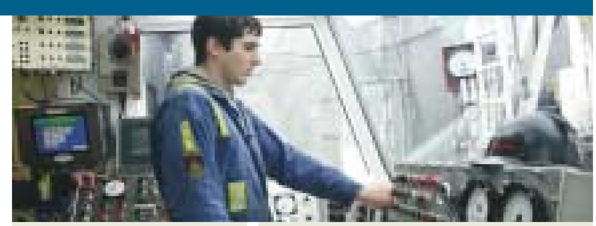
Located in northeast British Columbia, this natural gas resource play uses hydraulic fracturing and horizontal drilling to target primarily the Cadomin geological formation in the deep basin. EnCana captures competitive efficiencies by operating its large network of pipelines and gas plants.

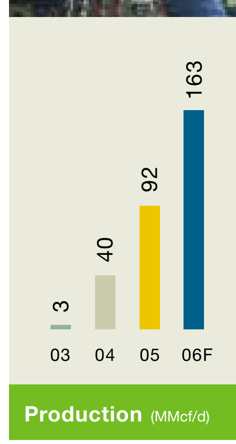
2005 Highlights

- Focused on horizontal drilling optimization which resulted in a simplified dual-leg horizontal well design that reduced drilling costs by 30% year-over-year.
- Improved horizontal well completions technology, which increased productivity by approximately 45% and decreased completion costs by 30% compared to 2004.
- Discovered the Cutbank Doig gas pool which is estimated to contain 350 to 550 billion cubic feet of original gas in place – exited the year producing 21 MMcf/d.
- Employed existing 3-D seismic from the Doig program to enhance the Cadomin formation development.
- Realized improved Cadomin well economics as a result of the revised provincial royalty incentive program.
- Supported changes to commingling regulations that will improve well completion efficiency.

Outlook

- Increase 2006 annual average production by about 75% from 2005.
- Continue exploitation of Cadomin and Doig formations.
- Construct new Steeprock gas plant, adding about 198 MMcf/d of processing capacity.
- Deploy new fit-for-purpose drilling rigs.





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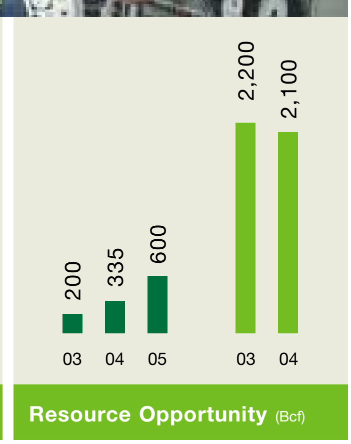


Proved reserves

Unbooked resource potential

3 Coalbed Methane

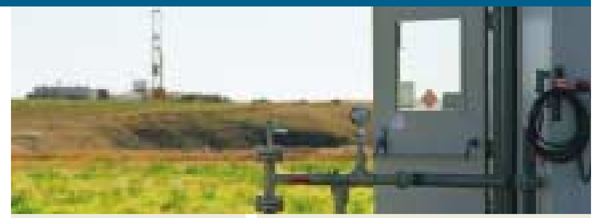
EnCana is a leading coalbed methane (CBM) producer in Canada. This is an early life resource play focused on dry coal seams in the Horseshoe Canyon formation in south central Alberta. EnCana captures value by leveraging its core competency in shallow gas development and its well-developed network of pipelines and gas plants across most of the company's CBM lands.

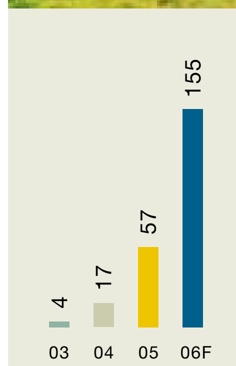
2005 Highlights

- Drilled 1,084 wells.
- Delivered more than a three-fold production increase to 57 MMcf/d.
- Worked closely with communities to help maintain favourable relations and land access.
- Employed fit-for-purpose well completions that decreased the amount of equipment deployed on site by up to 40%.

Outlook

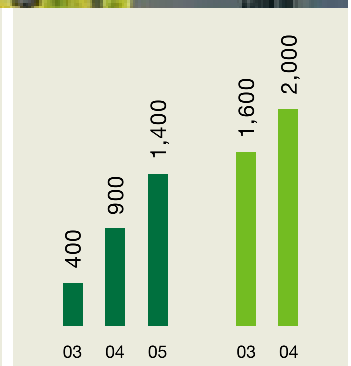
- Continue to pursue an integrated multi-zone strategy that includes commingled gas production from the sand and coal formations.
- Plan to increase annual average production to between 150 and 160 MMcf/d in 2006.
- Reduce development cycle times through co-ordination of key services, use of fit-for-purpose equipment, a focus on regulatory approvals and expanded stakeholder engagement practices.





Production (MMcf/d)

06F Midpoint of guidance



Resource Opportunity (Bcf)

Proved reserves

Unbooked resource potential

4 Shallow Gas

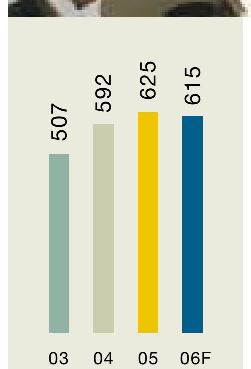
EnCana's Shallow Gas resource play located in southeast Alberta is a legacy asset and the foundation upon which the company's resource play strategy is modelled. This unconventional play has been producing for more than 30 years – that is three decades of developing knowledge, building resource play competency and demonstrating a track record for the future.

2005 Highlights

- Continued strong production averaging 625 MMcf/d, up about 6% from 2004, despite extremely wet weather and supply sector constraints.
- Implemented procurement initiatives to help offset growing cost pressures – examples include contract rig deals and fuel supply arrangements.

Outlook

- Advance reservoir understanding through down-spacing pilots.
- Continue to optimize existing operations through dewatering initiatives and improving infrastructure efficiency.



Production (MMcf/d)

06F Midpoint of guidance

Resource Opportunity (Bcf)

Proved reserves

Unbooked resource potential

5 Jonah

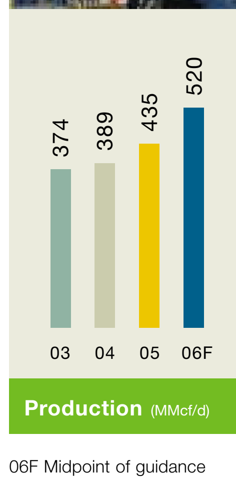
This southwest Wyoming resource play produces from 3,000 feet of vertically stacked sands in the Lance formation. Jonah is a great natural gas resource with original gas in place now estimated at 350 billion to 400 billion cubic feet per square mile.

2005 Highlights

- Advanced the Environmental Impact Statement (EIS), setting the stage for a ruling in the first half of 2006.
- Continued to focus on environmental stewardship – utilized industry's first natural gas powered drilling rig which reduced emissions and costs.
- Piloted minimal disturbance lease construction with surface drilling mats.
- Contracted for expanded processing and transportation capacity.
- Improved reservoir understanding through specialized core analysis, increasing the estimated gas in place.
- Piloted infill drilling wells down to five-acre spacing with multiple-fracture stimulations.
- Initiated 24-hour-a-day fracturing operations, reducing costs.

Outlook

- Obtain the final Record of Decision on the EIS for infill drilling, allowing up to 1,500 additional net wells.
- Accelerate development pace by increasing rig count to 14 or more rigs from an average of seven rigs in 2005.
- Pursue major expansion of third-party gathering and processing systems by year-end 2006.



6 Piceance

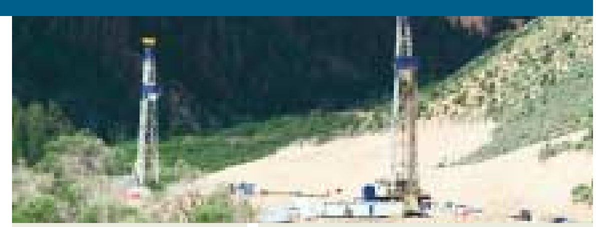
The Piceance resource play in western Colorado is focused on production from the thick, gas-charged Williams Fork formation. EnCana's large land position offers great potential as current proved reserves are derived from just 24% of the company's acreage within the region.

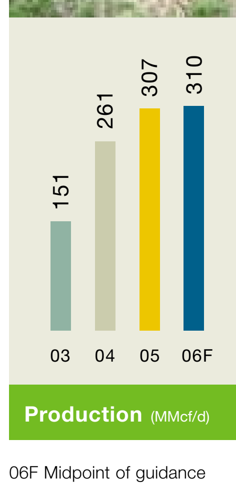
2005 Highlights

- Grew gas production 18% from 2004 and increased drilling inventory to more than 4,000 wells.
- Designed and implemented a drilling process enabling up to 32 wells from a single pad, significantly reducing surface area disturbance.
- Reduced regional transportation constraints with improved pipeline infrastructure.
- Negotiated processing and compression expansion to facilitate future growth.
- Designed and installed the north Piceance water distribution and gas gathering system, dramatically reducing traffic and emissions in the area.

Outlook

- Continue delineation of the resource by adding 13 new, fit-for-purpose drilling rigs through 2006.
- Focus on high grading well inventory, optimizing drilling schedule and reducing cycle times.
- Pursue major expansion of gathering and processing systems by year-end 2006.





7 Fort Worth

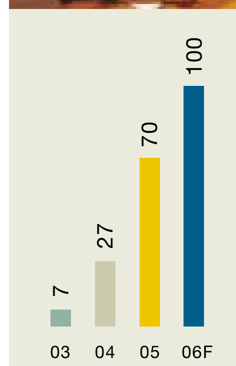
With a strong land position in the Barnett Shale play in north Texas, EnCana is currently one of the largest producers in the Fort Worth Basin. This resource play is a great example of how EnCana applies technology to unlock the potential of a complex reservoir. Through improved reservoir knowledge, EnCana has refined the application of horizontal drilling and multi-stage fracturing and has leveraged these efficiencies across the company's drilling program.

2005 Highlights

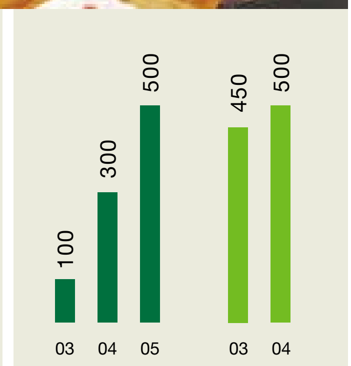
- Grew land position in the play to 205,000 net acres.
- Extended commercially proven play area to Parker, Hood and southern Johnson counties.
- Increased operated rig count from three to 11, averaging six during the year.

Outlook

- Accelerate development by increasing rig count to 13 rigs.
- Increase annual average production by more than 40% from 2005.
- Contract for new pipeline capacity to transport increased production to markets.
- Use fit-for-purpose drilling rigs to improve efficiency on multi-well pad sites.



Production (MMcf/d)



Resource Opportunity (Bcf)

06F Midpoint of guidance

Proved reserves

Unbooked resource potential

8 East Texas

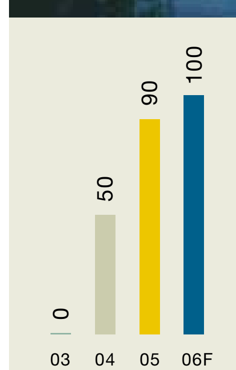
Acquired in 2004, EnCana's East Texas play targets a combination of tight gas, multi-zone plays, including the Bossier, Deep Bossier and Cotton Valley geological formations. The gas is located at depths ranging from 10,000 feet to 25,000 feet in the Bossier and Cotton Valley formations. EnCana is the largest landholder in the Deep Bossier play with 70,000 net acres.

2005 Highlights

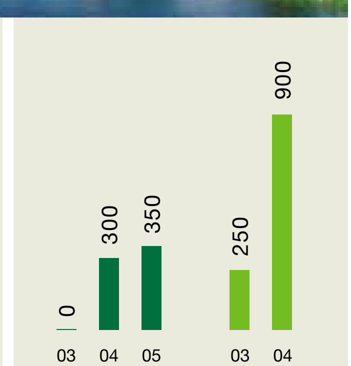
- Started a three rig drilling program in Deep Bossier play.
- Improved well tie-in efficiency by decreasing time from rig release to first sales from 17 to 13 days.
- Initiated 24-hour, multi-stage completion operations.

Outlook

- Increase drilling activity to five rigs in Deep Bossier play.
- Test horizontal drilling application in the Bossier formation.
- Expand limits of Bossier production in southern Robertson county.
- Transfer drilling expertise from Bossier shelf area to Deep Bossier with the goal of reducing drilling times by up to 50%.



Production (MMcf/d)



Resource Opportunity (Bcf)

06F Midpoint of guidance

Proved reserves

Unbooked resource potential

9 Foster Creek

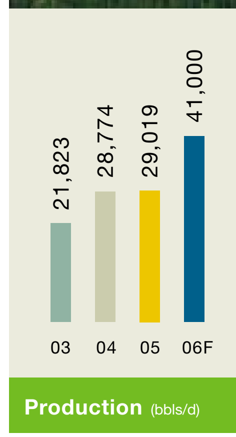
Started in 2001, Foster Creek is the industry's first commercial in-situ oilsands operation to use steam-assisted gravity drainage (SAGD) technology. The bitumen is produced from the McMurray formation of the Athabasca oilsands, located in northeast Alberta. Foster Creek represents the foundation for future in-situ development. From Foster Creek, Christina Lake and the recently announced Borealis project, EnCana is planning to expand production to 500,000 bbls/d of bitumen over the next 10 years. Foster Creek is expected to produce 150,000 bbls/d of this total.

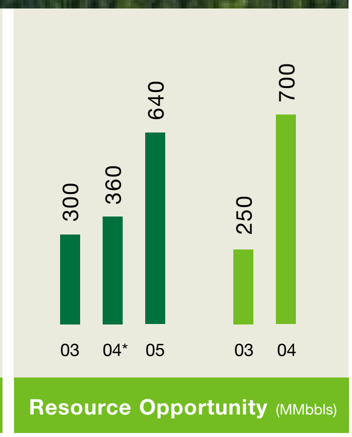
2005 Highlights

- Completed the first phase of current expansion, adding 10,000 bbls/d of production.
- Exited 2005 producing approximately 40,000 bbls/d.
- Drilled 39 horizontal well pairs.
- Improved technology and costs through better drilling waste management, application of high-temperature, high-volume pumps and testing of low-pressure SAGD operations.
- Decreased energy consumption through improved technology and lowering of steam-oil ratio to an industry-leading 2.3 times.
- Commenced operation of an 800,000-barrel underground storage facility which can hold both diluent and bitumen blend.

Outlook

- Increase productive capacity to 60,000 bbls/d by year-end 2006.
- Continue to improve technology with a focus on reducing operating costs and enhancing recovery.





06F Midpoint of guidance

Proved reserves

Unbooked resource potential

* before bitumen revision

10 Pelican Lake

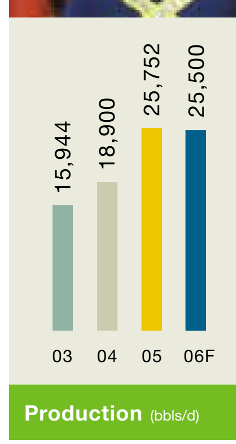
At Pelican Lake, heavy oil is produced from the Wabasca formation. This development in northeast Alberta has operated for about 10 years. The field is estimated to contain about 1.2 billion barrels of original oil in place.

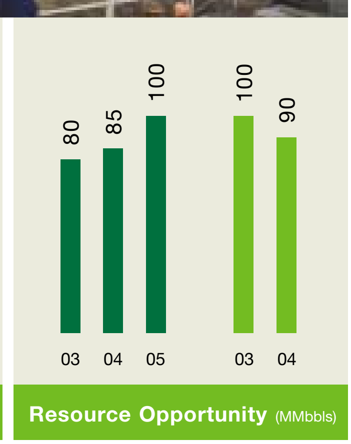
2005 Highlights

- Waterflood continued to perform well with recovery rates expected to reach 12% of original oil in place.
- Continued polymer flood injection pilot project, potentially extending the play's expected life.
- Grew proved reserves to 100 million barrels.

Outlook

- Continue application of technology. Waterflood and polymer injection are expected to increase recovery rates to as high as 20% of original oil in place.
- Expect to reach project payout in 2006, triggering royalty increase from 1% to 21% – project will continue to deliver strong returns.





06F Midpoint of guidance

Proved reserves

Unbooked resource potential

Midstream & Marketing

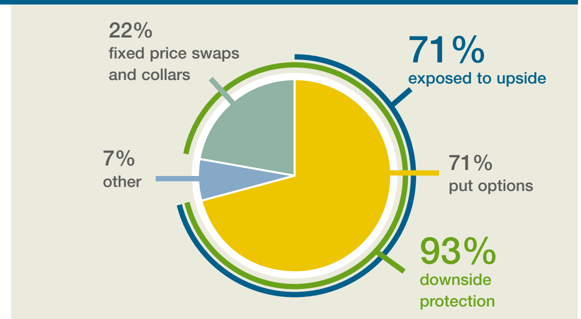
With the sale of the natural gas liquids business (NGLs) and announced sale of the Gas Storage business, the Midstream & Marketing group has refined its scope. Its key responsibility is to pursue and manage marketing initiatives that facilitate the execution of the company's long-term plan. Midstream & Marketing focuses on maximizing the value of the company's gas and oil sales, analysis of commodity fundamentals and execution of the company's price risk management program.

2005 Highlights

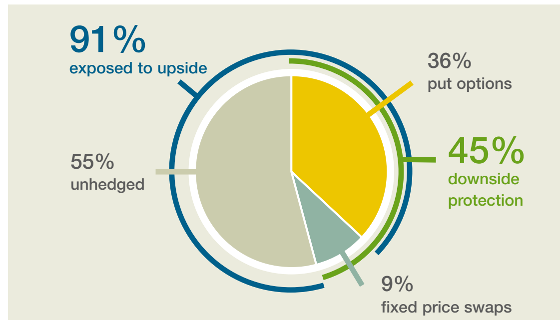
- Proceeded with permitting and construction of the Entrega Pipeline project.
- Signed 500 MMcf/d capacity agreement on the planned Rockies Express Pipeline to move gas from the Cheyenne Hub to the Eastern United States.
- Completed the divestiture of EnCana's NGL Midstream business for $625 million.
- Initiated the sales process of the company's Gas Storage operations.
- Implemented projects designed to supply and transport diluent to the company's in-situ oilsands operations.

Outlook

- Complete the Gas Storage divestiture process.
- Identify value enhancement opportunities in support of the development of EnCana's in-situ oilsands projects.



2006 Natural Gas Price Exposure



2006 Liquids Price Exposure

Frontier & International New Ventures

EnCana conducts option value exploration in pursuit of high return opportunities in select locations beyond the boundaries of onshore North America. Frontier & International New Ventures is dedicated to identifying and building new frontier areas and maximizing the value of existing positions.

2005 Highlights

- Completed divestiture of the company's offshore Gulf of Mexico assets for $2.1 billion before tax.
- Made a heavy oil discovery at BM-C-7 in the Campos Basin of Brazil and initiated its divestiture for $350 million before tax.
- Secured $55 million in third-party capital investment to pursue high-impact exploration opportunities in Oman, Qatar, Brazil and East Coast Canada to reduce the company's costs while maintaining exposure to upside.
- Successfully appraised and tested a natural gas discovery at Umiak in the Mackenzie Delta of Northern Canada.
- Acquired additional offshore blocks in Agência Nacional do Petróleo Bid Round 7 in Brazil.

Outlook

- Complete a seven- to nine-well drilling program in Chad to evaluate the resource potential of three basins.
- Commence drilling and evaluation of a potential gas resource play on the recently awarded 860,000 acre Foix Block in southwest France.
- Continue to evaluate options for the development of the Deep Panuke resource.
- Pursue offshore, deep water, light-medium oil exploration opportunities in Brazil, including acquisition of 3-D seismic surveys and drilling a well in the Campos Basin.

Corporate Responsibility and Governance

EnCana is **committed** to demonstrating **leadership,** engaging stakeholders and increasing transparency.

On-site safety meeting, Cutbank Ridge, British Columbia

Corporate reporting in all its forms is evolving because the company recognizes that it is measured by more than its financial success.

Previously, EnCana reported on corporate responsibility primarily in the annual report and on its corporate website. In order to provide a more comprehensive report on the company's corporate responsibility performance and in response to stakeholder feedback, a stand-alone Corporate Responsibility Report will be produced this year in addition to continued coverage on the external website. EnCana believes this evolution will provide easier access to information for external audiences, and greater efficiency in communicating with its stakeholders.

The stand-alone report, which EnCana intends to publish in June 2006, will demonstrate how a strong commitment to corporate responsibility enables the company to address challenges and achieve operational excellence.

Corporate Responsibility Management

Through the Corporate Responsibility Policy adopted in 2003, EnCana has committed to conducting its business ethically, legally and in a manner that is fiscally, environmentally and socially responsible, while delivering sustainable value and strong financial performance. This commitment to corporate responsibility applies to everything EnCana does, and everywhere it operates. To ensure that EnCana lives up to its commitments, the Board of Directors established a committee in 2003 to oversee corporate responsibility issues.

EnCana goes beyond simply having a policy commitment to corporate responsibility by developing and implementing management systems and associated programs that ensure its performance continues to improve. Corporate responsibility is integrated into EnCana's day-to-day operations – through a consistent approach to stakeholder engagement, a focus on implementing best environmental, health and safety practices, and fair treatment of employees and business partners.

Achieving Progress

In 2005, EnCana made progress on each of the corporate responsibility objectives outlined in its 2004 annual report. Highlights of this progress are outlined below, with further detail provided in the upcoming Corporate Responsibility Report.

Engaging Stakeholders and Working with Local Communities

- A Stakeholder Engagement Guide and training module was developed and introduced to key practitioners to facilitate a consistent approach to consultation and communication with individuals and communities affected by or involved with the company's operations.
- In 2005, EnCana contributed more than C$20 million to the communities in which it operates by supporting local economic development, investing in community facilities and providing donations to important community projects.
- EnCana also continued to actively support competitive Aboriginal businesses and partnerships in 2005, spending in excess of C$140 million on direct services, including environmental, drilling, seismic and catering services.

Building and enhancing relationships helps EnCana earn the social licence to operate, a key to sustaining our financial success.

Environmental Stewardship

- In Wyoming, EnCana adopted a "hub and spoke" drilling configuration that minimizes surface disturbances by more than 30 percent.
- In northeast British Columbia, the company is using wooden mats to protect sensitive muskeg environments during drilling.
- At EnCana's steam-assisted gravity drainage projects in northeast Alberta, steam use is among the industry's lowest. Consequently, less energy is used to extract a barrel of oil.
- At Foster Creek, EnCana's drilling waste management system recycles drilling waste into useful products, while reducing drilling and construction costs.

Enhancing Corporate Responsibility Reporting to Key Stakeholders

- EnCana has used the Global Reporting Initiative's Sustainability Reporting Guidelines to help determine which performance indicators to report. The company has engaged employees and investors, and considered guidance from the Canadian Association of Petroleum Producers to identify other indicators that are meaningful to its business and stakeholders. EnCana's upcoming Corporate Responsibility Report will provide information on a substantially expanded number of corporate responsibility performance indicators, including:

Environmental

- Greenhouse gases
- Air emissions
- Flaring and venting
- Energy and water use
- Spills

Social

- Employment creation and employee turnover
- Injury rates
- Adherence to the code of conduct

Economic

- Financial performance
- Community investments
- Cost of goods, materials and services
- Payroll and benefits
- Taxes

Visit EnCana's Corporate Responsibility Reporting web page at www.encana.com for information on how to obtain a copy of the 2005 Corporate Responsibility Report, to be published in June, or email your request to requestcrreport@encana.com.

We are committed to progressing and adapting our governance practices to address an ever-changing business environment.

David P. O'Brien
Chairman of the Board

Despite the dynamic nature of 2005, EnCana's commitment to strong corporate governance remained steadfast. During times of substantial change, your company's experienced leadership and sound corporate governance practices guided EnCana effectively through transitional events.

Succession Planning

The Board of Directors is responsible for ensuring processes are in place for succession planning of EnCana's senior management, including the appointment, training and monitoring of new management for the continued success of the company. For several years, the Board laid the groundwork for the appointment in 2005 of three of the most senior roles in the company.

By the time Gwyn Morgan, the company's President & Chief Executive Officer, announced his retirement after 30 years of company service, the Board had already invested several years in succession planning to ensure the most appropriate and capable leader assumed the CEO position. Randy Eresman, EnCana's Chief Operating Officer for three years and a 25-year veteran of the company, took over the role with the confidence of the Board, Executive Team and industry. As part of the transition, Gwyn, in his capacity as Executive Vice-Chairman, will be available as an advisor to the CEO.

Another valued member of EnCana's Executive Team, John Watson, Executive Vice-President & Chief Financial Officer, announced his retirement effective February 28, 2006. John, with 30 years of service, will be replaced by Brian Ferguson, who has been with the company for 21 years most recently as Executive Vice-President, Corporate Development. He is highly competent and well known in the financial community. John also remains with EnCana through 2006 in an advisory role.

Drude Rimell, Executive Vice-President, Corporate Services, also retired last year. Her replacement, Hayward Walls, has been leading our high-performance Information Services team since EnCana's inception in 2002. Drude will continue as an advisor to the CEO and Executive Team through 2006.

The seamless appointment of internal candidates to three of the most senior EnCana positions demonstrates the Board's dedication to succession planning. The Board will continue to emphasize the importance of succession planning to ensure the continued success of the company. The Board has every confidence in the ability and dedication of these individuals in their new roles.

Integrity

EnCana prides itself on being a high-performance, principled corporation. During 2005, the company implemented an Integrity Hotline which provides a way in which stakeholders can, confidentially or anonymously, report matters with respect to how EnCana conducts its business. Quarterly Hotline reporting is provided to the Board and the company plans to publish statistical information on Integrity Hotline activity in its first Corporate Responsibility Report due to be released in June of 2006.

Director Compensation

Last year, EnCana continued to review and make changes to director compensation to more closely align director compensation with shareholder returns. In 2005, EnCana terminated the Directors' Stock Option Plan (DSOP). As far back as October 2003, EnCana discontinued DSOP grants. In 2002, EnCana implemented a Deferred Share Unit Plan (DSU) for Directors, and as of April 2005 annual DSU grants were reduced from 7,000 to 5,000 for each director. Deferred Share Unit grants are not paid to a director until after retirement from the Board, which further ties the value of long-term incentives to total shareholder return.

Recognition

Canadian Business Magazine identifies the top 25 boards in Canada and publishes an annual governance ranking. Out of the top 25 companies identified – from a total of 228 companies reviewed – EnCana was ranked 6th with a score of 95 out of a possible 100, moving up five places from 11th last year. While we are proud of this tribute, we recognize that high standards of corporate governance are not static. We are committed to progressing and adapting our governance practices to address an ever-changing business environment.

Corporate Governance Compliance

EnCana continues to fully comply with the applicable corporate governance requirements, including the best practice guidelines published by the Canadian Securities Regulatory authorities, the provisions of the Sarbanes-Oxley Act of 2002 (SOX) and the rules adopted by the U.S. Securities and Exchange Commission. We are also in compliance with all applicable New York Stock Exchange requirements. We are committed to the high standards of transparent reporting and accountability that these requirements represent. Additional information about EnCana's commitment to corporate governance is contained in the company's Information Circular available at encana.com.

Resilience and Confidence

I would like to thank Bill Fatt, who is not standing for re-election, for his participation on the Board. Bill has served on the Board for 11 years and has contributed greatly to the company's success. He served on the Audit Committee since the merger in 2002 and on several other committees in previous years.

I would also like to welcome Randy Eresman to the Board. Randy's extensive experience, leadership abilities, technical expertise and long-term vision will serve him well in his role as President & Chief Executive Officer and as a director of EnCana.

Many will remember 2005 as a year of significant change but also as one marked by significant success. We have become a leading North American natural gas company focused on unconventional reservoirs. We are in the process of divesting the last of our major non-core conventional assets and we continue to execute our resource play strategy in the disciplined pursuit of increasing net asset value per share. Your company's success to date and its promise for the future are the product of your continued shareholder support and the dedication, knowledge and hard work of EnCana's employees and Board of Directors.

On behalf of the Board of Directors,

David P. O'Brien
Chairman of the Board

In Recognition

Putting things plainly, it is unlikely there would be an EnCana today without the vision, character and tenacity of Gwyn Morgan.

Gwyn would readily say he did not build EnCana alone, yet he has been fundamental to its success. Thirty years, from an inaugural engineer at Alberta Energy Company (AEC) to chief executive of Canada's largest natural gas and oil company, his career has been remarkable.

Gwyn conceived merging AEC and PanCanadian Energy Corporation and drove it to conclusion. He then sharpened its strategic focus, formulating unconventional thinking for energy in North America.

At his core, Gwyn is characterized by his manifesto on ethics, EnCana's Corporate Constitution. Published in 2003, it sets out the values foundation for employees and contractors to work by, behaviours necessary to sustain a high-performance and principled corporation.

On behalf of the Board of Directors, I thank Gwyn for his years of leadership and service. I commend him for his relentless pursuit of great achievements, his passion for excellence, and his disciplined approach to execution. And I salute him for his profound legacy – a successful and growing company with sustainable values that guide its success.

Gwyn Morgan looked beyond the ordinary and pursued the extraordinary, with character and style. We wish him and his family all the very best.

On behalf of the Board of Directors,

David P. O'Brien

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the audited Consolidated Financial Statements for the year ended December 31, 2005, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2004. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this MD&A. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") in United States dollars, except where another currency has been indicated.

This MD&A has been prepared in United States dollars. Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 16, 2006.

Readers can find the definition of certain terms used in this MD&A in the notes regarding Oil and Gas Information and Currency and Non-GAAP Measures at the end of this MD&A.

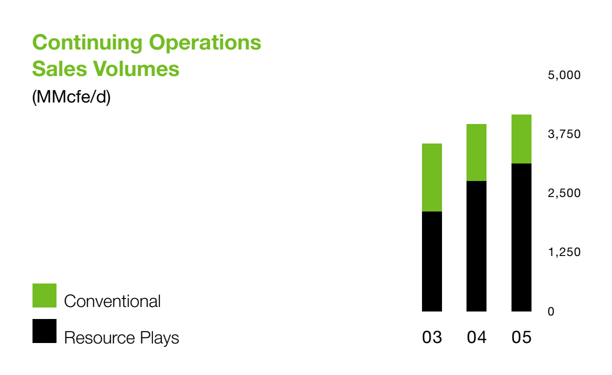
EnCana's Business

EnCana is a leading independent North American oil and gas company.

EnCana operates two continuing businesses:

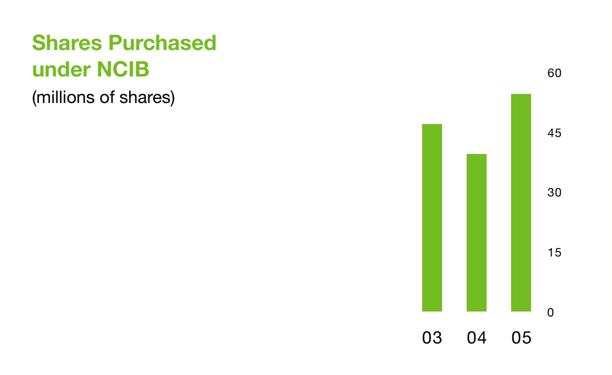
- Upstream includes the Company's exploration for and development and production of, natural gas, crude oil, and natural gas liquids ("NGLs") and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and the Canadian East Coast; and
- Market Optimization includes activities to enhance the sale of Upstream's production. As part of these activities Marketing buys and sells third party products that enhance EnCana's operating flexibility for transportation commitments, product type, delivery points and customer diversification.

2005 Review



EnCana pursues predictable, profitable growth from a portfolio of long-life resource plays in Canada and the United States. In 2005, EnCana:

- Grew total sales volumes from continuing operations to 4,163 million cubic feet ("MMcf") of gas equivalent per day ("MMcfe/d"), an increase of 5 percent over 2004;
    - Grew natural gas sales by 9 percent to 3,227 MMcf/d;
    - Achieved sales of approximately 51,000 barrels per day ("bbls/d") in December 2005 at EnCana's three steam-assisted gravity drainage ("SAGD") projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek increased from an average of 28,774 bbls/d in 2004 to approximately 40,000 bbls/d in December 2005, after completion of its expansion program in the fourth quarter of 2005;
- Replaced approximately 213 percent of natural gas production and 406 percent of liquids production through reserves additions. Proved natural gas reserves totaled 11,784 billion cubic feet ("Bcf") and proved liquids reserves totaled 1,120.6 million barrels ("MMbbls") at December 31, 2005;
- Made a substantial natural gas discovery below the Company's Cutbank Ridge resource play in British Columbia;
- Purchased about 325,000 net undeveloped acres with multi-zone gas resource play potential in the Maverick Basin in Texas for $148 million;
- Began construction of the Entrega natural gas pipeline out of the Piceance Basin in the U.S. Rockies; and
- Sold Gulf of Mexico assets for net proceeds of approximately $1,472 million after-tax; sold its NGLs processing business for approximately $625 million; sold certain non-core conventional oil and gas assets for proceeds of approximately $471 million; and reached an agreement in principle to sell all interests in Ecuador for approximately $1,420 million.



EnCana enhances its ability to build shareholder value through financial discipline, strength and flexibility. In 2005 the Company:

- Purchased 55.2 million common shares under the Normal Course Issuer Bid ("NCIB") for a total cost of $1,924 million and renewed the NCIB until October 2006;
- Redeemed nine issues of medium term notes for $1,036 million, including a $79 million after-tax charge to retire these notes;
- Reduced long-term debt by $1,039 million to $6,703 million on December 31, 2005;
- Split its common shares on a two-for-one basis; and
- Improved its net debt to EBITDA ratio from 1.4x at December 31, 2004, to 1.1x at December 31, 2005.

Business Environment

NATURAL GAS

In 2005, prices increased with concern over North America's ability to grow gas supply despite high drilling levels. A warm summer across North America and a cold December in the U.S. Northeast increased demand for power and two successive hurricanes damaged gas supply infrastructure in the U.S. Gulf Coast. Combined with high oil prices these factors caused the NYMEX gas price to average $8.62/MMBtu in 2005, a 40 percent increase from 2004.

Higher average AECO gas prices in 2005 compared with 2004 can be attributed to increased NYMEX prices partially offset by increased AECO/NYMEX basis differentials in 2005 compared to 2004.

Natural Gas Price Benchmarks

Year ended December 31 (Average for the period)	2005	2005 vs 2004	2004	2004 vs 2003	2003
AECO Price (C$/Mcf)	**$ 8.48**	**25%**	$ 6.79	1%	$ 6.70
NYMEX Price ($/MMBtu)	**8.62**	**40%**	6.14	14%	5.39
Rockies (Opal) Price ($/MMBtu)	**6.96**	**33%**	5.23	27%	4.12
AECO/NYMEX Basis Differential ($/MMBtu)	**1.59**	**75%**	0.91	40%	0.65
Rockies/NYMEX Basis Differential ($/MMBtu)	**1.66**	**82%**	0.91	-28%	1.27

CRUDE OIL

Global demand for oil is now pushing world refining capacity limits, resulting in more frequent crude oil product price spikes and historically high refining margins. An active hurricane season resulted in substantial interruptions to U.S. Gulf Coast production and refineries, which added to the world-wide tightness in refining capacity. The hurricane damage to production facilities in the Gulf of Mexico required the release of strategic reserves of crude oil in the United States and Europe to prevent prices from increasing to even higher levels.

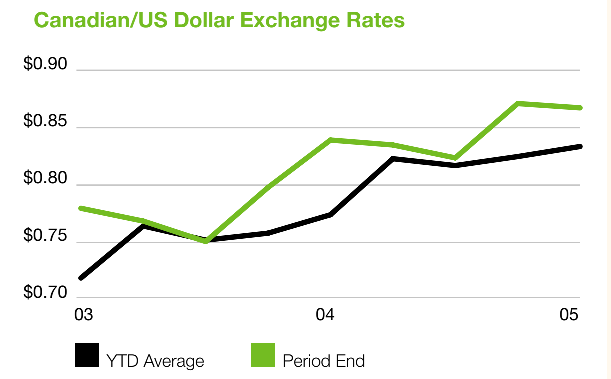
Year-over-year Canadian heavy oil differentials were 53 percent wider in absolute dollar terms mainly due to the higher price for West Texas Intermediate ("WTI"). The Bow River Blend average sales price for 2005 was 65 percent of WTI, compared to 69 percent of WTI in 2004, primarily due to very wide differentials in the early part of 2005. Bitumen field prices are normally at their weakest level each year in the fourth quarter due to seasonal fluctuations in asphalt and condensate prices. In December 2004 condensate prices were particularly high and the differential between WTI and heavy oil prices was wide, leading to very low field prices. In 2005, higher WTI and lower condensate premiums considerably strengthened the year-end field price.

Crude Oil Price Benchmarks

Year ended December 31 (Average for the period $/bbl)	2005	2005 vs 2004	2004	2004 vs 2003	2003
WTI	**$ 56.70**	**37%**	$ 41.47	34%	$ 30.99
WTI/Maya Differential	**15.70**	**38%**	11.41	68%	6.80
WTI/Bow River Differential	**19.64**	**53%**	12.82	60%	8.01
WTI/OCP NAPO Differential (Ecuador)	**18.37**	**28%**	14.33	78%	8.06

U.S./CANADIAN DOLLAR EXCHANGE RATES

The impacts of currency fluctuations on EnCana's results should be considered when analyzing the Consolidated Financial Statements. The value of the Canadian dollar increased by 7.4 percent or $0.057 to an average of US$0.825 in 2005 from an average of US$0.768 in 2004 which was approximately 7.3 percent or $0.052 higher than the 2003 average value. As a result, EnCana reported an additional $5.70 of costs for every hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices which are closely tied to the value of the U.S. dollar.



U.S./Canadian Dollar Exchange Rates

Year ended December 31	2005	2004	2003
Average U.S./Canadian dollar exchange rate	**$ 0.825**	$ 0.768	$ 0.716
Average U.S./Canadian dollar exchange rate for prior year	**$ 0.768**	$ 0.716	$ 0.637
Increase in capital, operating and administrative expenditures caused solely by fluctuations in exchange rates	**$ 5.70**	$ 5.20	$ 7.90

Acquisitions and Divestitures

In keeping with EnCana's North American resource play strategy, the Company completed the following significant divestitures in 2005:

- The sale of its natural gas liquids processing business on December 13 for approximately $625 million subject to post-closing adjustments;
- The sale of certain non-core Canadian conventional oil and gas assets on June 30 which were producing approximately 6,400 barrels of oil equivalent per day ("BOE/d") for approximately $321 million; and
- The sale of its Gulf of Mexico assets on May 26 for approximately $2.1 billion in cash. The net proceeds were approximately $1.5 billion after-tax and other adjustments. These assets were in the development and appraisal stage and accordingly there was no production.

Proceeds from these divestitures were directed primarily to a combination of debt reduction and the purchase of shares under EnCana's NCIB.

On November 21, 2005 EnCana announced that it had reached an agreement to sell its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. The sale is subject to closing conditions and regulatory approvals and is expected to close in the first quarter of 2006.

On September 13, 2005 EnCana announced that it had reached an agreement in principle to sell all of its shares in subsidiaries with oil and pipeline interests in Ecuador for approximately $1.42 billion. The sale will have an effective date of July 1, 2005 and is subject to other closing conditions and regulatory approvals. The sale, originally expected to close in 2005, is now expected to close in the first quarter of 2006.

EnCana is in the process of divesting of its natural gas storage business and expects to close the transaction in the second quarter of 2006.

During 2005 EnCana spent approximately $420 million to acquire undeveloped landholdings and minor amounts of natural gas production in the Fort Worth and East Texas key resource play areas in the United States.

Consolidated Financial Results

Year ended December 31 ($ millions, except per share [1] amounts)	2005	2005 vs 2004	2004	2004 vs 2003	2003
Total Consolidated					
Cash Flow [2]	**$ 7,426**	**49%**	$ 4,980	12%	$ 4,459
– per share – diluted	**8.35**	**57%**	5.32	14%	4.65
Net Earnings [3]	**3,426**	**-2%**	3,513	49%	2,360
– per share – basic	**3.95**	**3%**	3.82	53%	2.49
– per share – diluted	**3.85**	**3%**	3.75	52%	2.46
Operating Earnings [4]	**3,241**	**64%**	1,976	41%	1,399
– per share diluted	**3.64**	**73%**	2.11	45%	1.46
Total Assets	**34,148**	**9%**	31,213	29%	24,110
Long-Term Debt	**6,703**	**-13%**	7,742	27%	6,088
Cash Dividends	**238**	**30%**	183	32%	139
Continuing Operations					
Cash Flow from Continuing Operations [2]	**6,962**	**55%**	4,502	10%	4,102
Net Earnings from Continuing Operations	**2,829**	**35%**	2,093	-2%	2,138
– per share – basic	**3.26**	**44%**	2.27	1%	2.25
– per share – diluted	**3.18**	**42%**	2.24	—	2.23
Operating Earnings from Continuing Operations [4]	**3,048**	**63%**	1,872	39%	1,346
Revenues, Net of Royalties	**14,266**	**39%**	10,259	20%	8,521

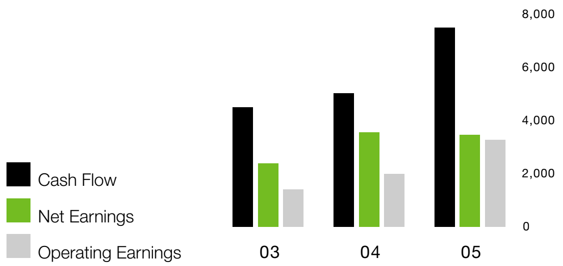
(1) Per share amounts have been restated for the effect of the common share split in 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under "Cash Flow".

(3) 2005 Net Earnings include an after-tax gain of $370 million on the sale of EnCana's natural gas liquids processing business, 2004 includes an after-tax gain of $1,364 million on the sale of EnCana's U.K. operations and 2003 includes an after-tax gain of $169 million on the sale of pipeline operations.

(4) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings".

Total Consolidated Cash Flow, Net Earnings and Operating Earnings
($ millions)



CASH FLOW

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors in measuring the Company's ability to finance capital programs and meet financial obligations. The calculation of cash flow is disclosed in the Consolidated Statement of Cash Flows in the Consolidated Financial Statements.

2005 vs 2004

EnCana's total 2005 cash flow was $7,426 million, an increase of $2,446 million or 49 percent from 2004. This increase reflects higher commodity prices in 2005 partially reduced by increased costs. EnCana's discontinued operations contributed $464 million to cash flow compared with $478 million in 2004.

EnCana's 2005 cash flow from continuing operations was $6,962 million, an increase of $2,460 million or 55 percent from 2004.

The increase resulted from:

- Average North American natural gas prices, excluding financial hedges, increased 36 percent to $7.46 per Mcf in 2005 compared to $5.47 per Mcf for 2004;
- North American natural gas sales volumes increased 9 percent to 3,227 MMcf/d; and
- Average North American liquids prices, excluding financial hedges, increased 26 percent to $36.17 per bbl in 2005 compared to $28.77 per bbl in 2004.

The increase in cash flow was partially reduced by:

- Operating expenses which increased 31 percent to $1,438 million in 2005 compared with $1,099 million in 2004;
- Interest expense which increased $126 million to $524 million in 2005. Almost all of this increase represents the cost to redeem certain notes in 2005; and
- The current tax provision, excluding income tax on the sale of assets, increased $67 million to $626 million compared with $559 million in 2004.

Realized financial commodities hedge losses were $441 million after-tax in 2005, relatively unchanged from $430 million after-tax in 2004.

2004 vs 2003

EnCana's total 2004 cash flow was $4,980 million, an increase of $521 million or 12 percent from 2003. This increase reflects the net impact of higher prices and growth in sales volumes reduced by realized financial hedge losses and increased costs. EnCana's discontinued operations contributed $478 million to cash flow compared with $357 million in 2003.

EnCana's 2004 cash flow from continuing operations was $4,502 million, an increase of $400 million or 10 percent from 2003.

The increase resulted from:

- Average North American natural gas prices, excluding financial hedges, increased 12 percent to $5.47 per Mcf in 2004 compared to $4.87 per Mcf in 2003;
- North American natural gas sales volumes increased 16 percent to 2,968 MMcf/d; and
- Average North American liquids prices, excluding financial hedges, increased 27 percent to $28.77 per bbl in 2004 compared to $22.72 per bbl in 2003.

The increase in cash flow was partially reduced by:

- Realized financial commodity hedge losses which increased $234 million to $430 million after-tax in 2004 from $196 million after-tax in 2003;
- Operating expenses which increased 14 percent to $1,099 million in 2004 compared with $965 million in 2003;
- Interest expense which increased $114 million to $398 million in 2004 as a result of increased long-term debt primarily as a result of the acquisition of Tom Brown, Inc. ("TBI"); and
- The current income tax provision which increased by $678 million to $559 million compared with a recovery of $119 million in 2003.

NET EARNINGS

2005 vs 2004

EnCana's 2005 total net earnings were $3,426 million compared with $3,513 million in 2004. Net earnings from discontinued operations decreased $823 million to $597 million; most of this decrease results from the 2005 after-tax gain of $370 million on the sale of substantially all of EnCana's natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana's U.K. operations.

EnCana's 2005 net earnings from continuing operations were $2,829 million, an increase of $736 million or 35 percent compared with 2004. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

- An increase in depreciation, depletion and amortization ("DD&A") of $390 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;
- Unrealized mark-to-market losses of $311 million after-tax in 2005 compared with losses of $117 million in 2004; and
- A $92 million after-tax unrealized foreign exchange gain on Canadian issued U.S. dollar debt in 2005 compared with a $229 million gain in 2004.

2004 vs 2003

EnCana's total 2004 net earnings were $3,513 million compared with $2,360 million in 2003. Discontinued operations contributed $1,420 million to net earnings in 2004, including an after-tax gain of $1,364 million on the sale of EnCana's U.K. operations.

EnCana's 2004 net earnings from continuing operations were $2,093 million, a decrease of $45 million or 2 percent compared with 2003. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

- An increase in DD&A of $412 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;
- Unrealized mark-to-market losses of $117 million after-tax in 2004, the first year when unrealized mark-to-market amounts were recognized in net earnings;
- A $229 million after-tax unrealized foreign exchange gain on Canadian issued U.S. dollar debt in 2004 compared with a $433 million after-tax gain in 2003; and
- Future tax recoveries due to a tax rate reduction of $109 million in 2004 compared with $359 million in 2003.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust net earnings and net earnings from continuing operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations has been prepared to provide investors with information that is more comparable between years.

Summary of Total Operating Earnings
Year ended December 31 ($ millions)

	2005	2005 vs 2004	2004	2004 vs 2003	2003
Net Earnings, as reported	**$ 3,426**	**-2%**	$ 3,513	49%	$ 2,360
Deduct: Gain on discontinuance, after-tax	**370**		1,364		169
Add: Unrealized mark-to-market accounting loss, after-tax	**(277)**		(165)		—
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax [1]	**92**		229		433
Deduct: Future tax recovery due to tax rate reductions	**—**		109		359
Operating Earnings [2][4]	**$ 3,241**	**64%**	$ 1,976	41%	$ 1,399

Year ended December 31 ($ per Common Share – Diluted)	2005	2005 vs 2004	2004	2004 vs 2003	2003
Net Earnings, as reported	$ 3.85	3%	$ 3.75	52%	$ 2.46
Deduct: Gain on discontinuance, after-tax	0.42		1.46		0.18
Add: Unrealized mark-to-market accounting loss, after-tax	(0.31)		(0.18)		—
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	0.10		0.24		0.45
Deduct: Future tax recovery due to tax rate reductions	—		0.12		0.37
Operating Earnings (2)(4)	$ 3.64	73%	$ 2.11	45%	$ 1.46

Summary of Operating Earnings from Continuing Operations

Year ended December 31 ($ millions)	2005	2005 vs 2004	2004	2004 vs 2003	2003
Net Earnings from Continuing Operations, as reported	$ 2,829	35%	$ 2,093	-2%	$2,138
Add: Unrealized mark-to-market accounting loss, after-tax	(311)		(117)		—
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	92		229		433
Deduct: Future tax recovery due to tax rate reductions	—		109		359
Operating Earnings from Continuing Operations (3)(4)	$ 3,048	63%	$ 1,872	39%	$ 1,346

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) Operating Earnings from Continuing Operations is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(4) Unrealized gains or losses have no impact on cash flow.

RESULTS OF OPERATIONS

Upstream Operations

Financial Results from Continuing Operations

Year ended December 31 ($ millions)	2005				2004				2003			
	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	$ 8,418	$ 1,764	$ 283	$10,465	$ 5,704	$ 1,320	$ 232	$ 7,256	$ 4,447	$ 1,170	$ 180	$ 5,797
Expenses												
Production and mineral taxes	401	52	—	453	270	41	—	311	153	11	—	164
Transportation and selling	465	60	—	525	416	56	—	472	360	69	—	429
Operating	733	305	313	1,351	519	285	222	1,026	402	300	170	872
Operating Cash Flow	$ 6,819	$ 1,347	$ (30)	$ 8,136	$ 4,499	$ 938	$ 10	$ 5,447	$ 3,532	$ 790	$ 10	$ 4,332
Depreciation, depletion and amortization				2,688				2,271				1,900
Upstream Income				$ 5,448				$ 3,176				$ 2,432

Upstream Revenues

2005 vs 2004

Revenues, net of royalties, increased in 2005 for the following reasons:

- A 36 percent increase in natural gas prices combined with a 9 percent increase in natural gas sales volumes; and
- A 26 percent increase in liquids prices.

Revenues, net of royalties, increases were reduced by:

- A 6 percent decrease in liquids volumes mainly as a result of property dispositions in the first and third quarters of 2004 and in June 2005.

Realized financial commodity hedging losses totalled $672 million in 2005 and were relatively unchanged from $669 million in 2004.

2004 vs 2003

Revenues, net of royalties, increased in 2004 for the following reasons:

- A 12 percent increase in natural gas prices combined with a 16 percent increase in natural gas sales volumes; and
- A 27 percent increase in liquids prices.

Revenues, net of royalties, increases were reduced by:

- Realized financial commodity and currency hedging losses totalled $669 million in 2004 compared to $297 million in 2003.

Revenue Variances for 2005 Compared to 2004 from Continuing Operations

Year ended December 31 ($ millions)	2004 Revenues, Net of Royalties	Revenue Variances in: Price(1)	Volume	**2005 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 3,928	$ 1,488	$ 70	**$ 5,486**
United States	1,776	557	599	**2,932**
Total Produced Gas	$ 5,704	$ 2,045	$ 669	**$ 8,418**
Crude Oil and NGLs				
Canada	$ 1,155	$ 491	$ (127)	**$ 1,519**
United States	165	61	19	**245**
Total Crude Oil and NGLs	$ 1,320	$ 552	$ (108)	**$ 1,764**

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 82 percent of the increase in revenues, net of royalties, in 2005 compared with 2004. The balance of the increase in revenues results from an increase in sales volumes.

The increase in produced gas volumes in Canada in 2005 was mainly due to drilling success in the key resource plays of Cutbank Ridge in northeast British Columbia and Shallow Gas and Coalbed Methane ("CBM") in central and southern Alberta. Dispositions of mature conventional producing assets during the first and third quarters of 2004 and natural production declines reduced the impact of these increases on total volumes.

The increase in produced gas volumes in the U.S. resulted from the Tom Brown, Inc. ("TBI") acquisition in May 2004 and drilling success at Jonah, Piceance, Fort Worth and East Texas.

The dispositions of mature Canadian conventional producing assets during the first and third quarters of 2004 and in June 2005 and natural production declines resulted in crude oil and NGLs volume reductions. These volume reductions were mitigated by increased production from the Pelican Lake heavy oil project.

UPSTREAM SALES VOLUMES

Sales Volumes Year ended December 31	2005	2005 vs 2004	2004	2004 vs 2003	2003
Produced Gas (MMcf/d)	**3,227**	**9%**	2,968	16%	2,553
Crude Oil (bbls/d)	**130,418**	**-7%**	140,379	-1%	142,326
NGLs (bbls/d)	**25,582**	**-2%**	26,038	10%	23,569
Continuing Operations (MMcfe/d)(1)	**4,163**	**5%**	3,966	12%	3,548
Discontinued Operations					
Ecuador (bbls/d)	**71,065**	**-9%**	77,993	68%	46,521
United Kingdom (BOE/d)(2)	**—**	**-100%**	20,973	71%	12,295
Syncrude (bbls/d)	**—**	**—**	—	—	7,629
Discontinued Operations (MMcfe/d)(1)	**426**	**-28%**	594	49%	399
Total (MMcfe/d)(1)	**4,589**	**1%**	4,560	16%	3,947

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

(2) Includes natural gas and liquids (converted to BOE).

Sales volumes from continuing operations increased in 2005 by 5 percent or 197 MMcfe/d for the following reasons:

- Production from EnCana's key resource plays increased approximately 18 percent for natural gas and 15 percent for crude oil;
- Drilling success in the key resource gas plays of Cutbank Ridge, Shallow Gas, CBM, Jonah, Piceance, Fort Worth and East Texas;
- Successful waterflood response at the Pelican Lake heavy oil project;
- Greater Sierra volumes have decreased in 2005 compared to 2004 due to the timing and pace of development drilling as well as delays in well tie-ins caused by weather issues in the earlier part of 2005; and
- Significant Canadian property dispositions in the first and third quarters of 2004 and June 2005 were offset somewhat by the full year impact of the TBI acquisition in May 2004. As a result, the net impact of acquisition and disposition activity in 2005 only reduced sales volumes by approximately 11 MMcfe/d.

Key Resource Plays	Daily Production					Drilling Activity (number of net wells drilled)		
	2005	2005 vs 2004	2004	2004 vs 2003	2003	2005	2004	2003
Natural Gas (MMcf/d)								
Jonah	**435**	**12%**	389	4%	374	**104**	70	59
Piceance	**307**	**18%**	261	73%	151	**266**	250	284
East Texas	**90**	**80%**	50	—	—	**84**	50	—
Fort Worth	**70**	**159%**	27	286%	7	**59**	36	5
Greater Sierra	**219**	**-5%**	230	61%	143	**164**	187	199
Cutbank Ridge	**92**	**130%**	40	1,233%	3	**135**	50	20
CBM	**57**	**235%**	17	325%	4	**1,084**	760	267
Shallow Gas	**625**	**6%**	592	17%	507	**1,267**	1,552	2,366
Oil (Mbbls/d)								
Foster Creek	**29**	**—**	29	32%	22	**39**	11	8
Pelican Lake	**26**	**37%**	19	19%	16	**52**	92	134
Total (MMcfe/d)	**2,224**	**18%**	1,892	34%	1,416	**3,254**	3,058	3,342

Per Unit Results – Produced Gas

Year ended December 31

($ per thousand cubic feet)	Canada 2005	2005 vs 2004	2004	2004 vs 2003	2003	United States 2005	2005 vs 2004	2004	2004 vs 2003	2003
Price	**$ 7.27**	**36%**	$ 5.34	10%	$ 4.87	**$ 7.82**	**35%**	$ 5.79	19%	$ 4.88
Expenses										
Production and mineral taxes	**0.10**	**25%**	0.08	14%	0.07	**0.81**	**25%**	0.65	38%	0.47
Transportation and selling	**0.36**	**-8%**	0.39	3%	0.38	**0.46**	**48%**	0.31	-23%	0.40
Operating	**0.67**	**29%**	0.52	8%	0.48	**0.53**	**43%**	0.37	32%	0.28
Netback	**$ 6.14**	**41%**	$ 4.35	10%	$ 3.94	**$ 6.02**	**35%**	$ 4.46	20%	$ 3.73
Gas Sales Volumes (MMcf/d)	**2,132**	**2%**	2,099	7%	1,965	**1,095**	**26%**	869	48%	588

2005 vs 2004

EnCana's realized natural gas prices for 2005 were $7.46 per Mcf, an increase of 36 percent compared with 2004. North American realized financial commodity hedging losses on natural gas for 2005 were approximately $377 million or $0.32 per Mcf compared to losses of approximately $238 million or $0.22 per Mcf in 2004.

Natural gas per unit production and mineral taxes in the U.S. increased $0.16 per Mcf or 25 percent in 2005 compared to 2004 as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 48 percent or $0.15 per Mcf for 2005 compared to 2004 primarily as a result of marketing TBI and Fort Worth gas volumes downstream of the wellhead in 2005.

Canadian natural gas per unit operating expenses for 2005 were 29 percent or $0.15 per Mcf higher compared to 2004 as a result of increased industry activity, the higher value of the Canadian dollar, higher repairs and maintenance and long-term compensation expenses. Natural gas per unit operating expenses in the U.S. increased 43 percent or $0.16 per Mcf for 2005 compared to 2004 mainly as a result of increased staffing levels attributable to growth, higher long-term compensation expenses, increased industry activity and higher workovers.

2004 vs 2003

EnCana's realized natural gas prices for 2004 were $5.47 per Mcf, an increase of 12 percent compared with 2003. North American realized financial commodity hedging losses on natural gas for 2004 were approximately $238 million or $0.22 per Mcf compared to losses of approximately $91 million or $0.10 per Mcf in 2003. Certain of the 2004 hedges were put in place to secure the economics of the TBI acquisition and will expire in December 2006.

Natural gas per unit production and mineral taxes in the U.S. increased 38 percent or $0.18 per Mcf in 2004 due to a combination of higher gas prices and a higher effective tax rate on the significant production growth in Colorado.

Natural gas per unit transportation and selling costs for the U.S. decreased 23 percent or $0.09 per Mcf in 2004 compared to 2003 primarily as a result of the TBI acquisition where a majority of the production was sold at the wellhead and did not incur transportation charges.

Canadian natural gas per unit operating expenses for 2004 were 8 percent or $0.04 per Mcf higher compared to 2003 primarily due to the higher value of the Canadian dollar. The increase in the U.S. natural gas per unit operating expenses of 32 percent or $0.09 per Mcf in 2004 compared to 2003 was a result of higher operating costs at properties acquired as part of the TBI acquisition, incremental operating costs associated with waste water disposal in Colorado and other non-recurring charges related to 2003.

Per Unit Results – Crude Oil

Year ended December 31

($ per barrel)	North America 2005	2005 vs 2004	2004	2004 vs 2003	2003
Price	**$ 34.15**	**22%**	$ 27.92	25%	$ 22.29
Expenses					
Production and mineral taxes	**0.58**	**41%**	0.41	356%	0.09
Transportation and selling	**1.20**	**13%**	1.06	-19%	1.31
Operating	**6.44**	**16%**	5.53	-5%	5.80
Netback	**$ 25.93**	**24%**	$ 20.92	39%	$ 15.09
Crude Oil Sales Volumes (bbls/d)	**130,418**	**-7%**	140,379	-1%	142,326

2005 vs 2004

The increase in the average crude oil price in 2005, excluding the impact of financial hedges, reflects the 37 percent increase in the benchmark WTI in 2005. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 53 percent). North American realized financial commodity hedging losses on crude oil were approximately $295 million or $5.18 per bbl of liquids in 2005 compared to losses of approximately $431 million or $7.08 per bbl of liquids in 2004.

Heavy oil sales in 2005 increased to 64 percent of total oil sales from 60 percent in 2004. This increase was mainly due to an increase in heavy oil production from the Pelican Lake property combined with dispositions of non-core conventional assets in 2004 and 2005 producing light/medium oil.

North American crude oil per unit production and mineral taxes increased by 41 percent or $0.17 per bbl in 2005 compared to 2004 primarily due to the impact of higher prices.

The 2005 crude oil per unit transportation and selling expenses in North America increased 13 percent or $0.14 per bbl mainly due to the higher value of the Canadian dollar and increased tariff rates as of July 2005.

North American crude oil per unit operating costs for 2005 increased 16 percent or $0.91 per bbl compared to 2004 mainly due to the higher value of the Canadian dollar, workovers, repairs and maintenance, fuel costs and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties increased the overall crude oil per unit operating costs.

2004 vs 2003

The increase in the average crude oil price in 2004, excluding the impact of financial hedges, reflects the 34 percent increase in the benchmark WTI in 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 60 percent). North American realized financial commodity hedging losses on crude oil were approximately $431 million or $7.08 per bbl of liquids in 2004 compared to losses of approximately $206 million or $3.41 per bbl of liquids in 2003.

Heavy oil sales in 2004 decreased to 60 percent of total oil sales from 62 percent in 2003. This decrease was mostly due to the sale of Petrovera and other non-core conventional assets in 2004 reduced slightly by higher heavy oil production from Foster Creek and Pelican Lake.

North American crude oil per unit production and mineral taxes in 2004 increased 356 percent or $0.32 per bbl compared to 2003 primarily as a result of mineral tax amendments related to prior years that were recorded in the third quarter of 2003. In addition, there were higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to the Alberta freehold mineral tax and Saskatchewan resource tax.

The 2004 crude oil per unit transportation and selling expenses in North America decreased 19 percent or $0.25 per bbl mainly due to an adjustment in oil transportation rates.

North American crude oil per unit operating costs for 2004 decreased 5 percent or $0.27 per bbl from 2003 mainly due to the sale of Petrovera, which had higher operating costs than other properties. This reduction was partially offset by the effect of the higher value of the Canadian dollar and higher fuel gas costs for the SAGD projects.

Per Unit Results – NGLs

Year ended December 31 ($ per barrel)	Canada 2005	2005 vs 2004	2004	2004 vs 2003	2003	United States 2005	2005 vs 2004	2004	2004 vs 2003	2003
Price	**$ 44.24**	**41%**	$ 31.43	30%	$ 24.26	**$ 48.36**	**36%**	$ 35.43	31%	$ 26.97
Expenses										
Production and mineral taxes	**—**	**—**	—	—	—	**4.86**	**27%**	3.82	88%	2.03
Transportation and selling	**0.42**	**2%**	0.41	141%	0.17	**0.01**	**—**	—	—	—
Netback	**$ 43.82**	**41%**	$ 31.02	29%	$ 24.09	**$ 43.49**	**38%**	$ 31.61	27%	$ 24.94
NGLs Sales Volumes (bbls/d)	**11,907**	**-11%**	13,452	-6%	14,278	**13,675**	**9%**	12,586	35%	9,291

2005 vs 2004

The increase in NGLs realized prices in 2005 generally correlates with strong WTI oil prices.

U.S. NGLs per unit production and mineral taxes for 2005 increased by 27 percent or $1.04 per bbl compared to 2004 as a result of the increase in NGLs prices.

2004 vs 2003

The increase in NGLs realized prices in 2004 generally correlates with strong WTI oil prices.

U.S. NGLs per unit production and mineral taxes in 2004 increased by 88 percent or $1.79 per bbl. Higher NGLs prices in 2004 and increased production growth in Colorado, which has a higher effective production tax rate, were the key reasons for this increase.

Per unit transportation and selling costs for NGLs in Canada increased by 141 percent or $0.24 per bbl in 2004 compared to 2003 as the Company incurred a full year of trucking charges for volumes in northeast British Columbia that came onstream in the fall of 2003.

Upstream Depreciation, Depletion and Amortization

2005 vs 2004

DD&A expenses in 2005 increased by $417 million or 18 percent for the following reasons:

- Sales volumes increased 5 percent;
- On a continuing operations basis, unit of production DD&A rates were $1.72 per Mcfe in 2005 compared to $1.53 per Mcfe in 2004. Rates increased in 2005 as a result of the higher value of the Canadian dollar and increased future development costs reduced by the effect of the 2005 Gulf of Mexico sale; and
- DD&A expense in 2005 included impairments of $7 million related to exploration prospects in Yemen and other areas.

2004 vs 2003

DD&A expenses in 2004 increased by $371 million or 20 percent for the following reasons:

- Sales volumes increased 12 percent;
- On a continuing operations basis, unit of production DD&A rates were $1.53 per Mcfe in 2004 compared to $1.39 per Mcfe in 2003. Rates increased in 2004 as a result of the higher value of the Canadian dollar and the impact of the acquisition of TBI; and
- DD&A expense in 2004 included impairments of $23 million related to exploration prospects in Ghana, Bahrain and other areas.

Market Optimization

Financial Results

Year ended December 31 ($ millions)	2005	2005 vs 2004	2004	2004 vs 2003	2003
Revenues	**$ 4,267**	**33%**	$ 3,200	18%	$ 2,722
Expenses					
Transportation and selling	**13**	**-28%**	18	-62%	47
Operating	**85**	**15%**	74	-20%	93
Purchased product	**4,159**	**35%**	3,092	20%	2,572
Operating Cash Flow	**10**	**-38%**	16	60%	10
Depreciation, depletion and amortization	**8**	**-83%**	47	81%	26
Segment Income (Loss)	**$ 2**	**106%**	$ (31)	-94%	$ (16)

2005 vs 2004

Revenues and purchased product expenses increased in 2005 compared to 2004 as a result of increases in commodity prices while third party optimization volumes remained relatively flat year over year.

In December, EnCana and Valero Energy Corporation completed their previously announced study of the conversion of Valero's Lima, Ohio refinery to refine Canadian heavy oil and decided not to proceed with the project. During 2005, EnCana expensed approximately $6 million of conversion study expenses.

2004 vs 2003

Revenues and purchased product expenses increased in 2004 compared with 2003 as a result of increases in commodity prices.

In 2004, a $35 million writedown in the values of EnCana's equity investment interest in the Trasandino Pipeline in Argentina and Chile increased DD&A expenses.

Corporate

Financial Results

Year ended December 31 ($ millions)	2005	2004	2003
Revenues	**$ (466)**	$ (197)	$ 2
Expenses			
Operating	**2**	(1)	—
Depreciation, depletion and amortization	**73**	61	41
Segment Loss	**$ (541)**	$ (257)	$ (39)
Administrative	**268**	197	173
Interest, net	**524**	398	284
Accretion of asset retirement obligation	**37**	22	17
Foreign exchange (gain) loss, net	**(24)**	(412)	(603)
Stock-based compensation – options	**15**	17	18
(Gain) on divestitures	**—**	(59)	(1)

2005 corporate revenues include approximately $466 million in unrealized mark-to-market losses related to financial commodity contracts compared with $197 million in 2004.

Price volatility has had a significant impact on the earnings impact of EnCana's price risk management activities. On December 31, 2005 the forward price curve for 2006 had increased from December 31, 2004 by 56 percent to $63.19 per bbl for WTI and 73 percent to $10.77 per Mcf for NYMEX gas.

Summary of Unrealized Mark-to-Market Gains (Losses)

Year ended December 31 ($ millions)	2005	2004[1]
Continuing Operations		
Natural Gas	**$ (494)**	$ (21)
Crude Oil	**28**	(177)
	(466)	(198)
Expenses	**3**	(7)
	(469)	(191)
Income Tax Recovery	**158**	74
	$ (311)	$ (117)

(1) Effective January 1, 2004 outstanding derivative instruments were recorded using mark-to-market accounting when EnCana adopted amendments to Canadian accounting standards.

2005 vs 2004

DD&A includes provisions for corporate assets such as computer equipment, office furniture and leasehold improvements.

Administrative expenses increased $71 million compared to 2004. The increase results from higher long-term compensation expenses that are tied to EnCana's common share price and the change in the U.S./Canadian dollar exchange rate. Administrative costs in 2005 were $0.18 per Mcfe compared with $0.14 per Mcfe in 2004.

Interest expense in 2005 increased as a result of a $121 million ($79 million after-tax) charge to retire certain medium term notes. EnCana's total long-term debt decreased by $1,154 million to $6,776 million at December 31, 2005 compared with $7,930 million at December 31, 2004. EnCana's 2005 weighted average interest rate on outstanding debt was 5.3 percent, up from an average of approximately 4.9 percent in 2004 as a result of increased interest rates in the marketplace.

The foreign exchange gain of $24 million in 2005 includes $113 million ($92 million after-tax) resulting from the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada. Under Canadian GAAP, EnCana is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

2004 vs 2003

The increase in DD&A expense in 2004 is the result of higher capital spending in prior periods on corporate capital items and the impact of the change in the U.S./Canadian dollar exchange rate.

Administrative expenses increased $24 million in 2004. The increase results from the change in the U.S./Canadian dollar exchange rate and increased long-term compensation expenses. Administrative costs were $0.14 per Mcfe in 2004 compared to $0.13 per Mcfe in 2003.

The higher interest expense resulted primarily from the higher average outstanding debt level during the year arising from the TBI acquisition in the second quarter of 2004. EnCana's weighted average interest rate on outstanding debt was marginally lower in 2004 than it was in 2003 which partially mitigated the effect of increased debt.

The majority of the foreign exchange gain of $412 million in 2004 resulted from the change in the U.S./Canadian dollar exchange rate in 2004 applied to U.S. dollar denominated debt issued in Canada.

During 2004, EnCana recorded gains of $59 million on the sale of certain corporate investments.

Income Tax

2005 vs 2004

The effective tax rate for 2005 was 30.8 percent compared with 23.2 percent in 2004. The 2005 income tax provision has been reduced by the net benefit of tax basis retained on dispositions of $68 million compared to $169 million in 2004. The 2004 effective tax rate included a reduction of $109 million in future income taxes resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent.

Current tax expense was $1,204 million in 2005 compared to $559 million in 2004; $578 million of this increase relates to the sale of Gulf of Mexico assets and has been shown as cash outflow from investing activities in the Statement of Cash Flows. The balance of $626 million has been included in cash flow.

2004 vs 2003

The effective tax rate for 2004 was 23.2 percent compared to 14.1 percent for 2003.

In 2003, future income taxes were reduced by $359 million as a result of reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the Canadian federal resource allowance deduction.

Further information regarding EnCana's effective tax rate can be found in Note 8 to the Consolidated Financial Statements. EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset dispositions where the tax values of the assets sold differ from their accounting values;
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations;
- The non-taxable half of Canadian capital gains or losses; and
- Items such as resource allowance and non-deductible Crown payments where the income tax treatment is different from the accounting treatment.

EnCana's operations are complex and related tax interpretations, regulations and legislation in the various jurisdictions in which 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.

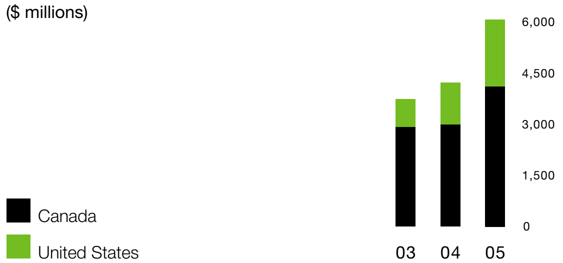
CAPITAL EXPENDITURES

Capital Summary

Year ended December 31 ($ millions)	2005	2004	2003
Upstream	**$ 6,202**	$ 4,343	$ 3,845
Market Optimization	**197**	10	5
Corporate	**78**	46	57
Total Core Capital Expenditures	**$ 6,477**	$ 4,399	$ 3,907
Acquisitions	**448**	2,952	540
Dispositions	**(2,523)**	(1,709)	(301)
Discontinued Operations	**(305)**	(1,436)	(724)
Net Capital Investment	**$ 4,097**	$ 4,206	$ 3,422

EnCana's capital investment was funded by cash flow from operations, proceeds from dispositions in excess of amounts paid for purchases of common shares under the NCIB and repayments of long-term debt. The Company's core capital expenditures increased approximately $2.1 billion to $6.5 billion in 2005.

Upstream Core Capital for Continuing Operations
($ millions)



UPSTREAM CAPITAL EXPENDITURES

2005 vs 2004

Capital spending during 2005 was primarily focused on North American resource play land capture, drilling programs and facility expansion. Natural gas capital expenditures were focused on continued development of the Company's key resource plays in Greater Sierra, Cutbank Ridge, Coalbed Methane and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2005 was concentrated on expansion of the Company's SAGD projects located at Foster Creek and Christina Lake, the waterflood program at Pelican Lake in Alberta and Weyburn in Saskatchewan. In addition, capital was directed at identifying and developing new resource plays at Bighorn and Borealis.

The $1.9 billion increase in Upstream core capital expenditures in 2005 compared to 2004 was primarily due to:

- Canadian core capital expenditures increased approximately $1.1 billion to $4.2 billion. This includes approximately

$219 million related to the change in the U.S./Canadian dollar exchange rate as well as the following factors:

- Crown land sales and other land costs in 2005 were $281 million higher than the prior year mainly due to significantly higher land prices;
- Drilling and completion costs increased $731 million in 2005 due to service cost increases as a result of industry activity levels;
- Facility costs increased $189 million in 2005 mainly due to the Foster Creek expansion which was completed in the fourth quarter of 2005;
- In Canada, the Company drilled 4,038 net wells in 2005 compared to 4,385 net wells in 2004. This decrease of 8 percent relates mainly to decreased drilling of shallow gas wells in southern and west-central Alberta due to weather related delays during the summer and service sector shortages as a result of record levels of activity in the industry.

- U.S. core capital expenditures increased $0.7 billion in 2005 to $2.0 billion primarily due to increases in drilling and completion costs. In the U.S. the Company drilled 617 net wells in 2005 compared to 534 net wells in 2004, an increase of 16 percent. Drilling was focused on continued development of the four key resource plays of Jonah, Piceance, Fort Worth, and East Texas.

2004 vs 2003

Capital spending during 2004 was primarily focused on North American resource play properties. Natural gas capital expenditures were primarily focused on continued development of the Company's key resource plays in Greater Sierra, Cutbank Ridge and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2004 was concentrated at Foster Creek, Pelican Lake and Suffield in Alberta and Weyburn in Saskatchewan.

The increase in Upstream capital expenditures in 2004 compared to 2003 reflects increased drilling and development activities in the U.S. The impact of the increased average U.S./Canadian dollar exchange rate resulted in an increase to Canadian dollar denominated core capital expenditures of approximately $230 million.

EnCana drilled 4,923 net wells in 2004 compared to 5,581 net wells in 2003.

Canadian East Coast EnCana continues to examine the economic viability of the Deep Panuke project. In 2005, EnCana participated in one offshore exploration well at Grand Pre and a sidetrack well in the Grand Pre licence in an attempt to extend the northeast boundary of the Deep Panuke field. Both wells were abandoned in January 2006. Negotiations continue with the Government of Nova Scotia regarding the terms of development for Deep Panuke.

Brazil Appraisal drilling on the offshore BM-C-7 block resulted in the identification of a viable field. In November 2005 an agreement was reached to dispose of the Company's 50 percent interest in the field for approximately $350 million. In the October 2005 bid round, EnCana acquired a working interest in two non-operated blocks, which were officially awarded in January 2006. As of December 31, 2005 the Company had invested approximately $106 million in Brazil.

Market Optimization Capital Expenditures

Expenditures in 2005 were mostly focused on construction activities underway for the Entrega Pipeline from Meeker Hub, Colorado to Wamsutter, Wyoming. Material portions of the pipeline construction were completed in December.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. The increase in spending in 2005 includes land purchased for the development of a Calgary office complex.

Acquisitions and Dispositions

Acquisitions included minor property acquisitions in 2005 and 2004 as well as the TBI acquisition in 2004.

Dispositions in 2005 include the sale of:

- Gulf of Mexico assets;
- Substantially all of EnCana's natural gas liquids processing business; and
- Certain non-core Canadian conventional oil and gas assets.

Dispositions in 2004 include the sale of:

- U.K. operations;
- Non-core conventional oil and gas assets;
- Petrovera Resources; and
- EnCana's interest in the Alberta Ethane Gathering system.

Proved Oil and Gas Reserves

Proved Reserves by Country

Constant Prices After Royalties

As at December 31	Natural Gas (billions of cubic feet) 2005	2005 vs 2004	2004	2004 vs. 2003	2003	Crude Oil and NGLs (1) (millions of barrels) 2005	2005 vs 2004(2)	2004	2004 vs. 2003	2003
Canada	**6,517**	**12%**	5,824	11%	5,256	**932.5**	**48%**	629.6	—	629.4
United States	**5,267**	**14%**	4,636	48%	3,129	**53.1**	**-42%**	91.0	119%	41.6
Ecuador	**—**	**—**	—	—	—	**135.0**	**-6%**	143.3	-11%	161.7
United Kingdom	**—**	**—**	—	-100%	26	**—**	**—**	—	-100%	124.5
Total	**11,784**	**13%**	10,460	24%	8,411	**1,120.6**	**30%**	863.9	-10%	957.2

(1) Crude Oil and NGLs include condensate.

(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to the bitumen price at year-end 2004.

Each year, EnCana engages independent qualified reserve evaluators to prepare reports on 100 percent of the Corporation's oil and natural gas reserves. The Company 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. EnCana's disclosure of reserves data is covered by NI 51-101 as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and Financial Accounting Standards Board ("FASB") reserve reporting requirements. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case December 31, 2005.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties

As at December 31, 2005	Natural Gas (billions of cubic feet) Canada	USA	Total	Crude Oil and NGLs (1) (millions of barrels) Canada	USA	Ecuador	Total
Beginning of year	5,824	4,636	10,460	266.9	91.0	143.3	501.2
Revisions and improved recovery	202	(260)	(58)	222.1	(3.2)	8.1	227.0
Extensions and discoveries	1,289	1,252	2,541	148.1	8.9	10.2	167.2
Acquisitions	7	76	83	—	0.4	—	0.4
Divestitures	(30)	(37)	(67)	(15.1)	(39.0)	—	(54.1)
Production	(775)	(400)	(1,175)	(52.2)	(5.0)	(26.6)	(83.8)
End of year before reinstatement of bitumen reserves	6,517	5,267	11,784	569.8	53.1	135.0	757.9
Reinstatement of bitumen reserves (2)	—	—	—	362.7	—	—	362.7
End of year	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6

(1) Crude Oil and NGLs include condensate.

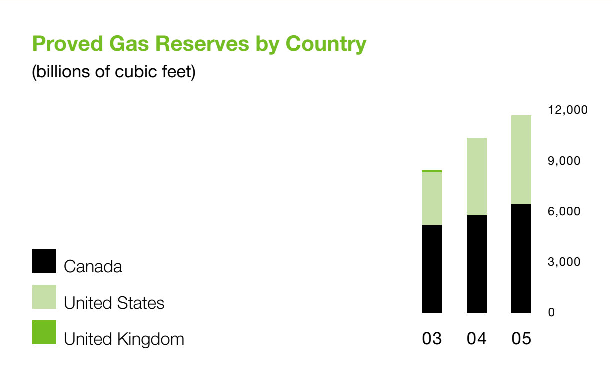
(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to the bitumen price at year-end 2004.

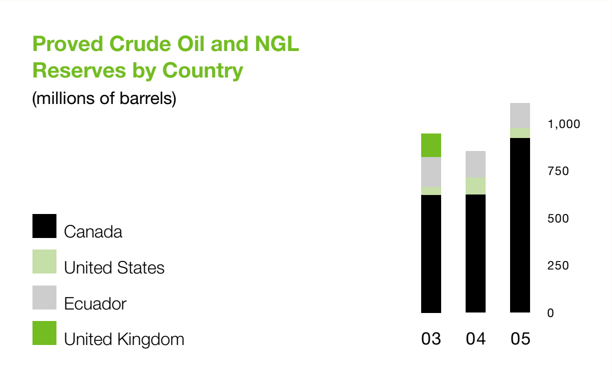
Natural Gas

EnCana's proved natural gas reserves as at December 31, 2005, on an SEC constant price basis, totalled 11,784 Bcf. Approximately 213 percent of 2005 production was replaced by reserves additions during 2005. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 2,541 Bcf. Downward revisions of 58 Bcf were less than 1 percent of natural gas reserves at the beginning of 2005. In Canada, positive revisions of 202 Bcf (or 3.5 percent of the opening balance) were largely associated with coalbed methane. Downward revisions in the United States amounted to 260 Bcf (or 5.6 percent of reserves at the beginning of 2005), the majority of which were the result of reduced reserve estimates per well in the southern Rockies. Acquisitions in the U.S. mid-continent essentially offset divestitures of non-core properties in the Gulf of Mexico and Canadian Plains.

Crude Oil and NGLs

The Company's proved crude oil and natural gas liquids reserves as at December 31, 2005, on an SEC constant price basis, totalled 1,120.6 MMbbls. Reserve additions replaced over 400 percent of production. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 167.2 MMbbls while revisions amounted to 227.0 MMbbls. Foster Creek accounted for the majority of these reserves additions. In addition, prices at December 31, 2005 allowed the reinstatement of 362.7 million barrels of bitumen that were recorded as a downward revision at year-end 2004 due to anomalously low bitumen prices on December 31, 2004. The sale of non core properties in the Gulf of Mexico and Canadian Plains accounted for the majority of the 54.1 million barrels of divestitures.





Discontinued Operations

Discontinued operations in the Consolidated Financial Statements include:

- Upstream
  - Ecuador
  - United Kingdom
- Midstream

EnCana's 2005 net earnings from discontinued operations were $597 million compared to $1,420 million in 2004 and include realized financial hedge losses of $86 million after-tax and unrealized financial hedge gains of $34 million after-tax.

EnCana's 2004 net earnings from discontinued operations were $1,420 million compared to $222 million in 2003 and include realized commodity hedge losses of $278 million after-tax (2003: $12 million after-tax) and unrealized financial hedge losses of $48 million after-tax.

Summary information is presented below. Additional information concerning EnCana's discontinued operations can be found in Note 4 to EnCana's Consolidated Financial Statements.

Ecuador

Year ended December 31	2005	2004	2003
Sales volumes			
Crude Oil (bbls/d)	**71,065**	77,993	46,521
($ millions)			
Net Earnings (loss) from Discontinued Operations	**$ 131**	$ (33)	$ 32
Capital Investment	**179**	240	367

In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

On September 13, 2005 EnCana announced it had reached an agreement in principle to sell all its interests in Ecuador operations for $1.42 billion which is approximately equivalent to the asset's net book value at July 1, 2005, the referenced effective date of the transaction. All economic benefits occurring after the July 1, 2005 effective date accrue to the purchaser. A provision of $234 million has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments at the sales date, as required under Canadian generally accepted accounting principles.

Contingency information regarding certain disputed items with the Ecuadorian government relating to value-added tax ("VAT"), ownership of Block 15 and deductibility of interest is included in Note 4 to EnCana's Consolidated Financial Statements.

2005 vs 2004

Production volumes in 2005 averaged 72,916 bbls/d; down 5 percent from 2004. Sales volumes in 2005 decreased 9 percent to average 71,065 bbls/d due to declining production in Tarapoa and Block 15 as well as the shift to an underlift position at December 31, 2005 from an overlift position at the end of 2004.

Production and mineral taxes were $70 million higher in 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. EnCana is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

2004 vs 2003

Production volumes for 2004 averaged 76,872 bbls/d; up 50 percent from 2003. Sales volumes in 2004 increased 68 percent to average 77,993 bbls/d. The higher sales volumes are primarily due to the combination of available capacity on the OCP pipeline in Ecuador, which commenced shipments in September 2003, and increased production from Block 15.

Production and mineral taxes were $36 million higher in 2004 compared to 2003 as a result of higher realized prices and sales volumes from the Tarapoa block.

United Kingdom

Year ended December 31	2005	2004	2003
Sales volumes			
Produced Gas (MMcf/d)	**–**	30	13
Crude Oil (bbls/d)	**–**	14,128	9,231
NGLs (bbls/d)	**–**	1,845	897
Total (BOE/d)	**–**	20,973	12,295
($ millions)			
Net Earnings (loss) from Discontinued Operations	**$ 35**	$ 1,338	$ (7)
Capital Investment	**–**	488	223

In December 2004, a subsidiary of the Company completed the sale of its U.K. central North Sea assets, production and prospects for net cash consideration of approximately $2.1 billion, resulting in a gain on sale of approximately $1.4 billion.

Midstream

Year ended December 31 ($ millions)	2005	2004	2003
Net Earnings from Discontinued Operations	**$ 431**	$ 118	$ 173
Capital Investment	**21**	88	271

2005 vs 2004

On December 13, 2005 EnCana sold substantially all of its natural gas liquids processing business for proceeds of approximately $625 million subject to post closing adjustments. EnCana continues with plans to divest its natural gas storage operations which include the AECO storage facility as well as storage facilities in the United States.

Net earnings in 2005 for the discontinued Midstream businesses were $431 million, an increase of $313 million over 2004. Included in 2005 net earnings is a $370 million gain on the sale of the natural gas liquids processing business. 2005 net earnings have been reduced by $30 million as a result of agreements by WD Energy Services Inc., one of EnCana's indirect subsidiaries, to settle certain California and New York lawsuits, as further described in this MD&A under the heading "Contractual Obligations and Contingencies."

2004 vs 2003

2004 net earnings of $118 million were $55 million lower than 2003.

In 2003 EnCana closed the previously announced sales of its crude oil pipeline business resulting in a $169 million after-tax gain on the sales.

Liquidity and Capital Resources

Operating Activities

Year ended December 31 ($ millions)	2005	2004	2003
Net cash provided by (used in)			
Operating activities	**$ 7,430**	$ 4,591	$ 4,304
Investing activities	**(4,520)**	(4,259)	(3,729)
Financing activities	**(3,396)**	163	(542)
Deduct: Foreign exchange loss on cash and cash equivalents held in foreign currency	**2**	6	10
(Decrease) increase in cash and cash equivalents	**(488)**	489	23

Cash flow from continuing operations was $6,962 million, an increase of $2,460 million from 2004. The increase in cash flow in 2005 was primarily due to increased revenues driven by higher commodity prices and sales volumes partially reduced by increased expenses. Cash flow from continuing operations comprises most of EnCana's cash provided by operating activities.

Investing Activities

Net cash of $4,520 million was used for investing activities in 2005, an increase of $261 million compared to 2004. Capital expenditures, including property acquisitions, increased $2,162 million in 2005. This increase occurred as a result of:

- The increased value of the Canadian dollar;
- Increased Crown land purchase prices and other land costs;
- Higher drilling and completion costs;
- Increased facility costs as a result of the Foster Creek expansion; and
- Entrega Pipeline construction costs.

EnCana's 2004 activities included the $2,335 million TBI acquisition. EnCana did not undertake any business combinations in 2005.

EnCana's divestments of the Gulf of Mexico assets, certain mature conventional properties and the natural gas liquids processing facilities generated $3.1 billion less tax of $578 million in 2005. In 2004, EnCana's divestments of the U.K. operations, certain mature conventional properties, Petrovera Resources and its interest in the Alberta Ethane Gathering System generated proceeds of $3.6 billion.

Financing Activities

Total long-term debt decreased by $1,154 million to $6,776 million in 2005 from the $7,930 million in 2004. EnCana's net debt adjusted for working capital was $7,970 million as at December 31, 2005 compared with $7,184 million at December 31, 2004. During 2005 EnCana purchased 60.7 million of its Common Shares for a total consideration of $2.1 billion. Working capital at December 31, 2005 was a deficit of $1,267 million. This compares to working capital of $558 million as at December 31, 2004.

Continuity of Long-Term Debt

2005			2004		
Date	Description	Amount	Date	Description	Amount
Repayment of long-term debt					
January	TBI Debt [1]	**$ (1)**	March	7.00% Term Securities due March 23, 2034	$ (97)
August	8.50% due March 15, 2011 [1]	**(42)**	June	6.60% due June 30, 2004	(39)
August	6.20% due June 23, 2028 [1]	**(42)**	August	8.50% Preferred Securities due September 30, 2048 [1]	(155)
September	5.95% due October 1, 2007 [1]	**(166)**	September	9.50% Preferred Securities due September 30, 2048 [1]	(150)
September	5.95% due June 2, 2008 [1]	**(83)**	December	7.00% due December 1, 2004	(77)
September	5.80% due June 19, 2008 [1]	**(83)**	December	8.40% due December 15, 2004	(73)
September	6.10% due June 1, 2009 [1]	**(125)**	Various	TBI Debt [1]	(407)
September	7.15% due December 17, 2009 [1]	**(125)**	Various	Bridge Facility [2]	(1,761)
September	7.10% due October 11, 2011 [1]	**(166)**			
September	7.30% due September 2, 2014 [1]	**(125)**			
November	8.75% Debentures due November 9, 2005	**(146)**			
		$ (1,104)			$ (2,759)
Issuances of long-term debt					
September	3.60% due September 15, 2008	**$ 429**	May	5.80% due May 1, 2014	$ 1,000
			August	6.50% due August 15, 2034	750
			August	4.60% due August 15, 2009	250
			Various	Bridge Facility [2]	1,761
		$ 429			$ 3,761
Other					
				Debt acquired in TBI acquisition	$ 408
	Net decrease in revolving term debt	**$ (538)**		Net increase in revolving term debt	72
	Other non cash items	**59**		Other non cash items	73
		$ (479)			$ 553
Increase (reduction) in total long term debt		**$ (1,154)**		Increase (reduction) in total long term debt	$ 1,555

(1) Redeemed prior to maturity.

(2) Bridge Facility used to fund the acquisition of TBI.

EnCana had available unused committed bank credit facilities in the amount of $3.0 billion and unused shelf prospectuses for up to $3.4 billion at December 31, 2005.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's has assigned a rating of A- with a 'Negative Outlook', Dominion Bond Rating Services has assigned a rating of A(low) with a 'Stable Trend' and Moody's has assigned a rating of 'Baa2 Stable'.

Financial Metrics

Year ended December 31	2005	2004
Net Debt to Capitalization	**33%**	33%
Net Debt to EBITDA [(1)]	**1.1x**	1.4x

(1) EBITDA is a non-GAAP measure that is defined as earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion, and amortization.

Net Debt to Capitalization and Net Debt to EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength.

Outstanding Share Data

Year ended December 31 (millions)	2005[(1)]	2004[(1)]	2003[(1)]
Outstanding, beginning of year	**900.6**	921.2	957.8
Issued under option plans	**15.0**	19.4	11.0
Shares purchased (Normal Course Issuer Bid)	**(55.2)**	(40.0)	(47.6)
Shares purchased (Performance Share Unit Plan)	**(5.5)**	—	—
Common shares outstanding, end of period	**854.9**	900.6	921.2
Weighted average common shares outstanding – diluted	**889.2**	936.0	959.4

(1) The number of common shares outstanding prior to the 2 for 1 share split has been restated for comparison.

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. There were no Preferred Shares outstanding.

EnCana's shareholders approved a split of the Company's outstanding Common Shares on a two-for-one basis at its Annual and Special Meeting held on April 27, 2005. Each shareholder received one additional Common Share for each Common Share held on the record date of May 12, 2005.

Employees and directors have been granted options to purchase Common Shares under various plans. On October 26, 2005 EnCana terminated the directors stock option plan. At December 31, 2005, 20.7 million options, without Tandem Share Appreciation Rights attached, were outstanding of which 16.8 million are exercisable.

Long-term incentives granted to EnCana employees include a reduced level of stock option grants that is supplemented by grants of Performance Share Units ("PSUs"). PSUs will not result in the issue of new Common Shares by the Company. Shares purchased for the PSUs plan are held in a Trust for future vesting. Stock options granted in 2004 and 2005 have an associated Tandem Share Appreciation Right ("TSAR") and employees may elect to exercise either the stock option or the associated TSAR. TSAR exercises will result in either cash payments by the Company or issuance of Common Shares based upon the employee's choice at the time of exercise.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under four consecutive NCIBs which commenced in October 2002 and may continue until October 30, 2006. Between October 2002 and December 31, 2005 EnCana has purchased 142.8 million shares for cancellation under these Bids for a total cost of $3,796 million. EnCana is entitled to purchase for cancellation up to approximately 85.6 million Common Shares under the renewed NCIB which commenced on October 31, 2005 and will terminate not later than October 30, 2006. As of January 31, 2006 EnCana has purchased 6.8 million shares under this NCIB. Under the prior NCIB which commenced October 29, 2004 and expired October 28, 2005, EnCana purchased approximately 84.2 million Common Shares. Shareholders may obtain a copy of the NCIB documents without charge at **www.sedar.com** or by contacting **investor.relations@encana.com**.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $238 million in 2005, $183 million in 2004 and $139 million in 2003. These dividends are funded by cash flow. At December 31, 2005 the quarterly dividend paid to shareholders was $0.075 per Common Share (2004: $0.050; 2003: C$0.050).

Normal Course Issuer Bid

Year ended December 31 (millions)	Share Purchases (1) 2005	2004
Bid expired October 2004	**—**	11.0
Bid expired October 2005	**55.2**	29.0
Bid expiring October 2006	**—**	—
	55.2	40.0

(1) Transactions that occurred before the 2 for 1 share split have been restated for comparison.

Contractual Obligations and Contingencies

Contractual Obligations (1)

($ millions)	Expected Payment Date 2006	2007 to 2008	2009 to 2010	2011+	Total
Long-Term Debt	$ 73	$ 864	$ 450	$ 5,325	$ 6,712
Asset Retirement Obligations	1	10	9	4,924	4,944
Pipeline Transportation	339	560	404	850	2,153
Purchase of Goods and Services	230	357	138	33	758
Operating Leases (2)	48	86	65	132	331
Product Purchases	33	45	44	98	220
Capital Commitments	92	29	—	38	159
Total	$ 816	$ 1,951	$ 1,110	$11,400	$15,277
Product Sales	$ 61	$ 132	$ 82	$ 300	$ 575
Discontinued Operations (3)	$ (331)	$ 67	$ 161	$ 793	$ 690
Financial Contracts and Other Commitments	$ (76)	$ 4	—	—	$ (72)

(1) In addition, the Company has made commitments related to its risk management program. See Note 16 to the Consolidated Financial Statements. The Company also has an obligation to fund its Pension Plan and Other Post Retirement Benefits as disclosed in Note 15 to the Consolidated Financial Statements.

(2) Related to office space.

(3) Primarily related to long term transportation commitments.

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana's total long-term debt commitments of $6,712 million at December 31, 2005 are $1,425 million in commitments related to Banker's Acceptances and Commercial Paper. 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. Further details regarding EnCana's long-term debt are described in Note 12 to the Consolidated Financial Statements.

As at December 31, 2005, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 149 Bcf at a weighted average price of $3.85 per Mcf. At December 31, 2005, these transactions had an unrealized loss of $464 million.

Contingency information regarding certain disputed items with the Ecuadorian government relating to VAT, ownership of Block 15 and deductibility of interest is included in Note 4 to EnCana's Consolidated Financial Statements.

Off-balance Sheet Financing Arrangements

EnCana does not have any off-balance sheet financing arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

Leases

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

Legal Proceedings

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

Discontinued Merchant Energy Operations

California

As disclosed previously, 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 whereby 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.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits 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.

In all but one of the class actions in the United States District Court and in the Gallo action, decisions dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims are on appeal to the United States Court of Appeals for the Ninth Circuit.

Without admitting any liability in the lawsuits, in November 2005, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD is also a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle the New York class action lawsuit subject to final documentation and approval by the New York District Court.

Based on the aforementioned settlements, during the fourth quarter of 2005 a total of $30 million has been recorded in Administrative expenses in Net Earnings from Discontinued Operations. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding 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

CHANGES IN ACCOUNTING PRINCIPLES

No changes in accounting principles were adopted in 2005.

RECENT ACCOUNTING PRONOUNCEMENTS

Management is assessing the following new and revised accounting pronouncements that have been issued and are not yet effective:

- In the quarter ending March 31, 2006 EnCana will adopt Section 3831 "Non-Monetary Transactions" issued by the Canadian Institute of Chartered Accountants ("CICA") in June 2005. Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Company does not expect application of this new standard to have a material impact on its consolidated financial statements.
- In the year ending December 31, 2007 EnCana will be required to adopt Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement" and Section 3865 "Hedges" issued by the CICA in January 2005. Under the new standards: a new financial statement, Comprehensive Income has been introduced that will provide for certain gains and losses, including foreign currency translation adjustment and other amounts arising from changes in fair value to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives are to be included on EnCana's balance sheet and measured at fair values in most cases. Requirements for hedge accounting have been further clarified. Although the Company is in the process of evaluating the impact of these standards, it does not expect the Financial Instruments and Hedges standards to have a material impact on its consolidated financial statements as it currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.
- Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada ratified in January 2006. As part of that plan, accounting standards in Canada for public companies will converge with International Financial Report Standards ("IFRS") over the next five years. EnCana continues to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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. A summary of EnCana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs directly associated with the acquisition of, exploration for, and 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 DD&A. 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.

Oil and Gas Reserves

All of EnCana's oil and gas reserves are evaluated and reported on by independent qualified reserve evaluators. 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. 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 the carrying amount, the impairment loss is limited to an 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.

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 initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. 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. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired in the merger with Alberta Energy Company and the acquisition of TBI, is assessed by EnCana for impairment at least annually. Goodwill was allocated to the business segments at the time of the above transactions 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.

Derivative Financial Instruments

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

The Company enters into financial transactions to help 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.

EnCana may also use derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of its 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.

EnCana 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.

EnCana 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.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives are recognized in natural gas and crude oil revenues as the related production occurs. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators. In 2004 and 2005, the Company elected not to designate any of its current price risk management activities as accounting hedges and accordingly, accounts for all derivatives using the mark-to-market accounting method.

Pensions and Other Post Retirement Benefits

EnCana 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 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service 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.

Performance Share Units ("PSUs")

The PSU plans provide for a range of payouts, based on EnCana's performance relative to certain peers.

EnCana expenses the cost of PSUs based on expected payouts, however, the amounts to be paid, if any, may vary from the current estimate.

Risk Management

EnCana's results are affected by:

- financial risks (including commodity price, foreign exchange, interest rate and credit risks)
- operational risks
- environmental, health, safety and security risks
- reputational risks

FINANCIAL RISKS

Sensitivity of 2006 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Including Hedges) (1)(2)

($ millions)

	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 520	$ 760
$6.00 per barrel increase in the WTI oil price	130	180
$0.01 decrease in the U.S./Canadian dollar exchange rate	5	40

(1) Hedge position as at December 31, 2005.

(2) Based on forward curve commodity price and forward curve estimates dated December 31, 2005.

Sensitivity of 2006 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Excluding Hedges) (1)

($ millions)

	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 780	$ 980
$6.00 per barrel increase in the WTI oil price	130	180
$0.01 decrease in the U.S./Canadian dollar exchange rate	5	40

(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2005.

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk, the Company has entered into various financial instrument agreements. EnCana does not use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of December 31, 2005, are disclosed in Note 16 to the Consolidated Financial Statements.

EnCana 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 price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

COMMODITY PRICE

To partially mitigate the natural gas commodity price risk, the Company entered into swaps which fix the AECO and NYMEX prices and collars and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized gain of $71 million.

EnCana 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. Physical contracts associated with this activity had an unrecognized gain of $70 million.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, purchased call options to allow participation at higher WTI levels, three-way put spreads and put options.

FOREIGN EXCHANGE

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, EnCana may enter into foreign exchange contracts. The Company also enters 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.

EnCana also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

INTEREST RATES

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana has entered into interest rate swap transactions from time to time as a means of managing the fixed/floating rate debt portfolio mix.

CREDIT RISK

EnCana is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions to counterparties of investment grade credit quality and transactions that are fully collateralized. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry.

OPERATIONAL RISKS

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

Projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project's history of Lookback results and the type of expenditure. A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

EnCana also partially mitigates operational risks by maintaining a comprehensive insurance program.

ENVIRONMENT, HEALTH, SAFETY AND SECURITY RISKS

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana 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 recommends approval of 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.

Security risks are managed through a Security Program designed to protect EnCana's personnel and assets. EnCana has established an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations.

Climate Change

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to 6 percent below 1990 levels over the period 2008 – 2012. There is currently no clear direction post 2012. The previous Federal Government released a framework outlining its Climate Change action plan on April 13, 2005. The plan as released contains few technical details regarding the implementation of the Government's greenhouse gas reduction strategy.

Prior to the recent change in the Federal Government, the implementation of the Climate Change plan had yet to be finalized, therefore EnCana is unable to predict the total impact of the potential regulations upon its business. However, a July 16, 2005 Canada Gazette notice partially addressed the uncertainty associated with a greenhouse gas regulation for existing facilities by providing the oil and gas sector with limits on cost (a price assurance mechanism of $15/tonne for compliance) and emission reductions targets that will not exceed 12 percent lower than business as usual levels of total covered emissions for a given sector. It also made a commitment to targets based on the "best technology economically achievable" for new facilities. Based on these commitments and EnCana's activity on geological sequestration of CO_2, we do not anticipate that the cost implications of government climate change plans will have a material impact on operations or future growth plans.

The ultimate impact of Canada's implementation plan, however, remains subject to numerous risks and uncertainties, including the outcome of discussions between the recently elected Federal Government, provincial governments, the resulting legislation, the emission reduction target obligations among economic sectors, and other administrative details. The Climate Change Working Group of the Canadian Association of Petroleum Producers will continue to work with the Federal and Alberta Governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's greenhouse gas emissions will be available in the Corporate Responsibility Report that will be published in the second quarter of 2006. The Report will be available on **www.encana.com**.

REPUTATIONAL RISKS

EnCana takes a pro-active approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

Quarterly Results

Quarterly Summary

($ millions, except per share [1] amounts)	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Total Consolidated								
Cash Flow [2]	**$2,510**	**$1,931**	**$1,572**	**$1,413**	$1,491	$1,363	$1,131	$ 995
per share – diluted	**2.88**	**2.20**	**1.76**	**1.55**	1.60	1.46	1.21	1.07
Net Earnings (Loss)	**2,366**	**266**	**839**	**(45)**	2,580	393	250	290
per share – basic	**2.77**	**0.31**	**0.96**	**(0.05)**	2.81	0.43	0.27	0.31
per share – diluted	**2.71**	**0.30**	**0.94**	**(0.05)**	2.77	0.42	0.27	0.31
Operating Earnings [3]	**1,271**	**704**	**655**	**611**	573	559	379	465
per share – diluted	**1.46**	**0.80**	**0.73**	**0.67**	0.62	0.60	0.41	0.50
Continuing Operations								
Cash Flow from Continuing Operations [2]	**2,390**	**1,823**	**1,502**	**1,247**	1,358	1,256	1,029	859
Net Earnings (Loss) from Continuing Operations	**1,869**	**348**	**774**	**(162)**	1,055	463	270	305
per share – basic	**2.19**	**0.41**	**0.89**	**(0.18)**	1.15	0.50	0.29	0.33
per share – diluted	**2.14**	**0.40**	**0.87**	**(0.18)**	1.13	0.50	0.29	0.33
Operating Earnings from Continuing Operations [3]	**1,229**	**733**	**611**	**475**	513	555	368	436
Revenues, Net of Royalties	**5,860**	**2,982**	**3,386**	**2,038**	3,542	2,195	2,374	2,148

(1) Per share amounts have been restated for the effect of the common share split in 2005.
(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under "Cash Flow".
(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings".

Natural gas prices in the fourth quarter of 2005 were higher than the same period in 2004. A cold December in the U.S. Northeast combined with continued supply losses from hurricane damage and high crude oil prices caused NYMEX gas prices to remain high through the fourth quarter.

The WTI crude oil price was 24 percent higher in the fourth quarter of 2005 than the same period in 2004. An active hurricane season resulted in substantial interruptions to the U.S. Gulf Coast production and refineries. The hurricane damage prompted the United States and Europe to release emergency supplies into the market, which prevented prices from increasing to even higher levels. Fourth quarter Canadian heavy oil differentials were wider in dollar terms relative to the fourth quarter of 2004, primarily due to the higher price for WTI.

EnCana's net earnings for the fourth quarter of 2005 were $2,366 million, down $214 million from 2004. Net earnings from discontinued operations decreased $1,028 million to $497 million; most of this decrease results from the 2005 after-tax gain on the sale of substantially all of EnCana's natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana's U.K. operations.

EnCana's net earnings from continuing operations in the fourth quarter of 2005 increased $814 million or 77 percent to $1,869 million compared with the same period in 2004. The increase resulted from:

- Average North American natural gas prices, excluding financial hedges, increased 69 percent to $10.29 per Mcf, compared to $6.08 per Mcf in 2004;
- Average North American liquids prices, excluding financial hedges, increased 23 percent to $37.16 per bbl in 2005 compared to $30.20 in 2004;
- Natural gas sales volumes increased 8 percent from the comparable period in 2004 to 3,326 MMcf/d; and
- Unrealized financial commodity hedging gains of $661 million after-tax in 2005 compared with $411 million after-tax in 2004.

The increase in net earnings from continuing operations was reduced by:

- Realized financial commodity hedging losses of $229 million after-tax compared with $145 million after-tax in 2004;
- Operating expenses increased 46 percent to $452 million in 2005 compared with $309 million in 2004. The increase in the average U.S./Canadian dollar exchange rate in 2005, increased workovers, repairs and maintenance, higher electrical costs and rising costs as a result of increased industry activity were significant reasons for this increase; and
- A $21 million after-tax foreign exchange loss on Canadian issued U.S. dollar debt in 2005 compared to a $131 million after-tax unrealized foreign exchange gain in 2004; this reflects the quarter-end decrease in the value of the Canadian dollar in 2005 compared to a quarter-end increase in the same period in 2004.

During the fourth quarter of 2005, EnCana:

- Sold substantially all of the natural gas liquids processing business on December 13, 2005 for proceeds of approximately $625 million subject to post-closing adjustments;
- Announced an agreement on November 21, 2005 to sell the 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million;
- Repaid long-term debt of $145 million; and
- Received regulatory approval to renew its Normal Course Issuer Bid. EnCana did not purchase any shares to December 31, 2005 under this renewed Bid.

Quarterly Sales Volumes	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Produced Gas (MMcf/d)	**3,326**	**3,222**	**3,212**	**3,146**	3,087	3,096	3,001	2,684
Crude Oil (bbls/d)	**134,178**	**124,402**	**132,294**	**130,826**	132,061	142,506	144,347	142,669
NGLs (bbls/d)	**25,111**	**26,055**	**24,814**	**26,358**	27,409	27,167	26,340	23,208
Continuing Operations (MMcfe/d) (1)	**4,282**	**4,125**	**4,155**	**4,089**	4,044	4,114	4,025	3,679
Discontinued Operations								
Ecuador (bbls/d)	**69,943**	**68,710**	**73,176**	**72,487**	77,876	74,846	78,303	80,982
United Kingdom (BOE/d) (2)	**—**	**—**	**—**	**—**	13,927	20,222	26,728	22,755
Discontinued Operations (MMcfe/d) (1)	**419**	**412**	**439**	**435**	551	570	630	623
Total (MMcfe/d) (1)	**4,701**	**4,537**	**4,594**	**4,524**	4,595	4,684	4,655	4,302

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Includes natural gas and liquids (converted to BOE).

Outlook

EnCana plans to continue to focus principally on growing natural gas production from unconventional resource plays in North America.

EnCana will also continue to develop its high quality in-situ oilsands resources and will continue to evaluate marketing options that will help expand their development.

Volatility in crude oil prices is expected to continue throughout 2006 as a result of market uncertainties over supply and refining disruptions on the U.S. Gulf Coast, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. North American conventional gas supply has peaked in the past two years and EnCana believes that unconventional resource plays can offset conventional gas production declines. The industry's ability to respond to the gas supply constrained situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2006 core capital investment program to be funded from cash flow.

Proceeds from the sales of non-core properties are expected to be used to reduce debt and for purchases under the Company's NCIB program.

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.

Advisories

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this Annual Report constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. 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: the potential value upside of investing in the Company's shares, including the Company's potential ability to build net asset value per share, and potential future profitable production growth per share; projections of proved reserves, reserves life index, resource opportunity, Unbooked Resource Potential, original oil in place, original gas in place, gross recoverable amounts, and production and growth potential, including the Company's plans therefor, and associated capital costs with respect to EnCana's various regions, assets and initiatives; projected returns which may be generated from various projects, assets and initiatives; the potential production, scalability and upside associated with resource plays; the potential success, growth, timing and production in 2006 and beyond, including for such projects as Greater Sierra, Cutbank Ridge, Coalbed Methane, Shallow Gas, Jonah, Piceance, Fort Worth, East Texas, Foster Creek and other SAGD oilsands projects and Pelican Lake, and projected original gas and/or oil in place and Unbooked Resource Potential which may be associated therewith; the Company's projections with respect to its ability to develop resource plays, the percentage of production from resource plays in the future and the impact of increasing the Company's proportion of resource play assets on future decline rates and the reliability and predictability of resource and production growth over multiple decades; projections relating to the timing for converting Unbooked Resource Potential into proved reserves; projected gas and oil resource life cycles and project returns, including projections for the various phases of project life cycles for various projects, assets and initiatives including exploration and piloting, primary development, maintenance and decline; projections with respect to the impact of the Company's long-term procurement initiatives, including contracts for drilling rigs in 2006 and beyond, and the impact of such initiatives on future drilling timing and costs; projected expansions of various gathering, processing and transportation systems and initiatives and their respective commencement and in-service dates; projections relating to the number of wells which may be drilled in 2006 and beyond; the projected timing for receipt of, and the content of, anticipated regulatory approvals, including with respect to Jonah; projections relating to the expansion of, and increased production from the Company's oilsands operations over the next 10 years; projections relating to potential recovery rates, including potential oil recovery rates for Pelican Lake; projections relating to the volatility of crude oil prices in 2006 and beyond and the reasons therefor; the Company's projected capital investment levels for 2006 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; the impact of the Kyoto Accord on operating costs; the adequacy of the Company's provision for taxes; the impact of changes in accounting principles on future consolidated financial statements; the Company's plans to divest of its natural gas storage business and Ecuador operations, and projections relating to the use of proceeds therefrom, including debt repayment and purchases under its Normal Course Issuer Bid. 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 and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; 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; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; risks associated with technology; the Company's 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 or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate, including Ecuador; the risk of international 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 made against the Company and its subsidiaries; 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 "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves 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.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana 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 by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, Natural Gas Liquids and Natural Gas Conversions

In this Annual Report, certain crude oil and natural gas liquids ("NGLs") volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Resource Play, Estimated Ultimate Recovery, Unbooked Resource Potential, Total Resource Portfolio and Total Resource Life

EnCana uses the terms resource play, estimated ultimate recovery, unbooked resource potential, total resource portfolio and total resource life. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. EnCana defines unbooked resource potential as quantities of oil and gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

CURRENCY AND NON-GAAP MEASURES

All information included in this Annual Report and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.85 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this Annual Report do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and EBITDA and therefore 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 Annual Report 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's use of these measures has been disclosed further in this Annual Report as these measures are discussed and presented.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at **www.sedar.com** and on the Company's website at **www.encana.com.**

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 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 requirements applicable to U.S. companies listed on the NYSE under NYSE corporate governance standards. A summary of these significant differences is available on EnCana's website (**www.encana.com**)**.** Except as described in this summary, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

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 judgments. Financial information contained throughout the annual report is consistent with these financial statements.

Management has overall responsibility for internal controls and 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 Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York 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.

Randall K. Eresman
President &
Chief Executive Officer

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

February 6, 2006

Auditor's Report

To the Shareholders of EnCana Corporation

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2005 and December 31, 2004 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 6, 2006

Consolidated Statement of Earnings

For the years ended December 31 ($ millions, except per share amounts)		2005	2004	2003
Revenues, Net of Royalties	(Note 3)			
Upstream		**$ 10,465**	$ 7,256	$ 5,797
Market Optimization		**4,267**	3,200	2,722
Corporate				
Unrealized (loss) gain on risk management		**(466)**	(198)	–
Other		**–**	1	2
		14,266	10,259	8,521
Expenses	(Note 3)			
Production and mineral taxes		**453**	311	164
Transportation and selling		**538**	490	476
Operating		**1,438**	1,099	965
Purchased product		**4,159**	3,092	2,572
Depreciation, depletion and amortization		**2,769**	2,379	1,967
Administrative		**268**	197	173
Interest, net	(Note 6)	**524**	398	284
Accretion of asset retirement obligation	(Note 13)	**37**	22	17
Foreign exchange (gain) loss, net	(Note 7)	**(24)**	(412)	(603)
Stock-based compensation – options	(Note 14)	**15**	17	18
(Gain) on divestitures	(Note 5)	**–**	(59)	(1)
		10,177	7,534	6,032
Net Earnings Before Income Tax		**4,089**	2,725	2,489
Income tax expense	(Note 8)	**1,260**	632	351
Net Earnings From Continuing Operations		**2,829**	2,093	2,138
Net Earnings From Discontinued Operations	(Note 4)	**597**	1,420	222
Net Earnings		**$ 3,426**	$ 3,513	$ 2,360
Net Earnings From Continuing Operations per Common Share	(Note 17)			
Basic		**$ 3.26**	$ 2.27	$ 2.25
Diluted		**$ 3.18**	$ 2.24	$ 2.23
Net Earnings per Common Share	(Note 17)			
Basic		**$ 3.95**	$ 3.82	$ 2.49
Diluted		**$ 3.85**	$ 3.75	$ 2.46

Consolidated Statement of Retained Earnings

For the years ended December 31 ($ millions)		2005	2004	2003
Retained Earnings, Beginning of Year		**$ 7,935**	$ 5,276	$ 3,523
Net Earnings		**3,426**	3,513	2,360
Dividends on Common Shares		**(238)**	(183)	(139)
Charges for Normal Course Issuer Bid	(Note 14)	**(1,642)**	(671)	(468)
Retained Earnings, End of Year		**$ 9,481**	$ 7,935	$ 5,276

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheet

As at December 31 ($ millions)		2005	2004
Assets			
Current Assets			
Cash and cash equivalents		$ 105	$ 593
Accounts receivable and accrued revenues		1,851	1,566
Risk management	(Note 16)	495	317
Inventories	(Note 9)	103	58
Assets of discontinued operations	(Note 4)	1,050	971
		3,604	3,505
Property, Plant and Equipment, net	(Notes 3, 10)	24,881	22,503
Investments and Other Assets	(Note 11)	496	334
Risk Management	(Note 16)	530	87
Assets of Discontinued Operations	(Note 4)	2,113	2,325
Goodwill		2,524	2,459
	(Note 3)	$ 34,148	$ 31,213
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,741	$ 1,742
Income tax payable		392	357
Risk management	(Note 16)	1,227	224
Liabilities of discontinued operations	(Note 4)	438	436
Current portion of long-term debt	(Note 12)	73	188
		4,871	2,947
Long-Term Debt	(Note 12)	6,703	7,742
Other Liabilities		93	118
Risk Management	(Note 16)	102	192
Asset Retirement Obligation	(Note 13)	816	611
Liabilities of Discontinued Operations	(Note 4)	267	213
Future Income Taxes	(Note 8)	5,289	5,082
		18,141	16,905
Commitments and Contingencies	(Note 18)		
Shareholders' Equity			
Share capital	(Note 14)	5,131	5,299
Share options, net		—	10
Paid in surplus		133	28
Retained earnings		9,481	7,935
Foreign currency translation adjustment		1,262	1,036
		16,007	14,308
		$ 34,148	$ 31,213

See accompanying notes to Consolidated Financial Statements.

Approved by the Board

David P. O'Brien
Director

Barry W. Harrison
Director

Consolidated Statement of Cash Flows

For the years ended December 31 ($ millions)		2005	2004	2003
Operating Activities				
Net earnings from continuing operations		**$ 2,829**	$ 2,093	$ 2,138
Depreciation, depletion and amortization		**2,769**	2,379	1,967
Future income taxes	(Note 8)	**56**	73	470
Cash tax on sale of assets	(Note 8)	**578**	—	—
Unrealized loss on risk management	(Note 16)	**469**	191	—
Unrealized foreign exchange (gain)		**(50)**	(285)	(545)
Accretion of asset retirement obligation	(Note 13)	**37**	22	17
(Gain) on divestitures	(Note 5)	**—**	(59)	(1)
Other		**274**	88	56
Cash flow from continuing operations		**6,962**	4,502	4,102
Cash flow from discontinued operations		**464**	478	357
Cash flow		**7,426**	4,980	4,459
Net change in other assets and liabilities		**(281)**	(176)	(84)
Net change in non-cash working capital from continuing operations	(Note 17)	**497**	1,565	(744)
Net change in non-cash working capital from discontinued operations		**(212)**	(1,778)	673
		7,430	4,591	4,304
Investing Activities				
Business combinations	(Note 2)	**—**	(2,335)	—
Capital expenditures	(Note 3)	**(6,925)**	(4,763)	(4,356)
Proceeds on disposal of assets	(Note 5)	**2,523**	1,456	301
Cash tax on sale of assets		**(578)**	—	—
Corporate (acquisitions)	(Note 5)	**—**	—	(91)
Equity investments		**—**	47	(6)
Net change in investments and other		**(109)**	44	(16)
Net change in non-cash working capital from continuing operations	(Note 17)	**330**	(29)	(112)
Discontinued operations		**239**	1,321	551
		(4,520)	(4,259)	(3,729)
Financing Activities				
Net (repayment) issuance of revolving long-term debt		**(538)**	72	288
Repayment of long-term debt		**(1,104)**	(2,759)	(142)
Issuance of long-term debt		**429**	3,761	500
Issuance of common shares	(Note 14)	**294**	281	114
Purchase of common shares	(Note 14)	**(2,114)**	(1,004)	(868)
Dividends on common shares		**(238)**	(183)	(139)
Other		**(125)**	(5)	(13)
Discontinued operations		**—**	—	(282)
		(3,396)	163	(542)
Deduct: Foreign Exchange Loss on Cash and Cash Equivalents Held in Foreign Currency		**2**	6	10
(Decrease) Increase in Cash and Cash Equivalents		**(488)**	489	23
Cash and Cash Equivalents, Beginning of Year		**593**	104	81
Cash and Cash Equivalents, End of Year		**$ 105**	$ 593	$ 104

Supplemental Cash Flow Information (Note 17)

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Prepared using Canadian Generally Accepted Accounting Principles.
All amounts in US$ millions, unless otherwise indicated.
For the year ended December 31, 2005

1. Summary of Significant Accounting Policies

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana has adopted the U.S. 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. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana is in the business of exploration for, production and marketing of natural gas, crude oil and natural gas liquids, as well as natural gas storage, 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 ("EnCana" or the "Company"), 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 19.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana's exploration and production business and are accounted for using the proportionate consolidation method, whereby EnCana's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana 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 period-end exchange rates, while revenues and expenses are translated using average rates over the period. 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 Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts 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 natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the consolidated 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.

The amount of compensation expense accrued for long-term performance based compensation arrangements are subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

D) Revenue Recognition

Revenues associated with the sales of EnCana's natural gas, crude oil and natural gas liquids ("NGLs") are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana 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. Realized gains and losses from the Company's commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Revenues associated with the services provided where EnCana 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 power is provided to the customer.

Unrealized gains and losses from the Company's commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) Transportation and Selling Costs

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

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

The cost of pensions and other retirement and post-employment 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 for the defined benefit pension plan 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 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service 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 plans.

H) Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded 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. Investment tax credits are recorded as an offset to the related expenditures.

I) 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 share amounts are calculated giving effect to the potential dilution that would occur if stock options without tandem share appreciation rights attached 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 without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) 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.

K) 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.

L) Property, Plant and Equipment

Upstream

EnCana accounts for natural gas and crude oil 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, including internal costs and asset retirement costs, directly 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.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. 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 percent 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. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

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 the 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.

Midstream and Market Optimization

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.

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years. Land is carried at cost.

M) 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.

N) 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.

O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed 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.

P) Asset Retirement Obligation

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 initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

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 in 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.

Q) Stock-based Compensation

EnCana records compensation expense in the Consolidated Financial Statements for stock options that do not have tandem share appreciation rights attached to them granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes-Merton option-pricing model. Compensation costs are recognized over the vesting period.

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

R) Derivative Financial Instruments

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic 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.

EnCana 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 identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) Recent Accounting Pronouncements

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- Beginning with the year ending December 31, 2007 the Company will be required to adopt the Canadian Institute of Chartered Accountants ("CICA") Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", and Section 3865 "Hedges", which were issued in January 2005. Under the new standards a new financial statement, Consolidated Statement of Other Comprehensive Income, has been introduced that will provide for certain gains and losses, including foreign currency translation adjustment and other amounts arising from changes in fair value to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives are to be included in the Company's Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. Although EnCana is in the process of evaluating the impact of these standards, the Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.
- Beginning with the first quarter of 2006, the Company will adopt CICA Section 3831 "Non-Monetary Transactions". Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. EnCana does not expect application of this new standard to have a material impact on its Consolidated Financial Statements.
- For the next five years CICA will adopt its new strategic plan for the direction of accounting standards in Canada, which was ratified in January 2006. As part of that plan, accounting standards in Canada for public companies will converge with International Financial Report Standards ("IFRS") over the next five years. The Company continues to monitor and assess the impact of convergence of Canadian GAAP with IFRS.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2005.

2. Business Combinations

Tom Brown, Inc. ("TBI")

On May 19, 2004, EnCana, through a wholly owned subsidiary, completed the tender offer for the shares of Tom Brown, Inc. ("TBI"), a Denver based independent energy company, for total cash consideration of $2.3 billion plus the assumption of $406 million of long-term debt.

As part of the acquisition, EnCana acquired certain natural gas and crude oil properties in west Texas and New Mexico and the assets of Sauer Drilling Company, a subsidiary of TBI, which were designated as assets held for sale at the date of acquisition. These assets were sold on July 30, 2004.

The calculation of the purchase price and the allocation to assets and liabilities is shown below:

Calculation of Purchase Price:	
Cash paid for common shares of TBI	$ 2,341
Transaction costs	13
Total purchase price	$ 2,354
Plus: Fair value of liabilities assumed	
Current liabilities	224
Long-term debt	406
Other non-current liabilities	39
Future income taxes	774
Total Purchase Price and Liabilities Assumed	$ 3,797
Fair Value of Assets Acquired:	
Current assets (including cash acquired)	$ 425
Property, plant and equipment, net	2,890
Other non-current assets	9
Goodwill (allocated to Upstream)	473
Total Fair Value of Assets Acquired	$ 3,797

3. 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, crude oil and natural gas liquids and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East and Greenland.
- Market Optimization is conducted by the Midstream & Marketing division. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Upstream segment. Correspondingly, the Marketing groups' also undertake market optimization activities which comprise third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization purchases substantially all of the Company's North American Upstream production for sale to third party customers. 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.

Operations that have been discontinued are disclosed in Note 4.

Results of Continuing Operations

For the years ended December 31	Upstream 2005	Upstream 2004	Upstream 2003	Market Optimization 2005	Market Optimization 2004	Market Optimization 2003
Revenues, Net of Royalties	**$ 10,465**	$ 7,256	$ 5,797	**$ 4,267**	$ 3,200	$ 2,722
Expenses						
Production and mineral taxes	**453**	311	164	**–**	–	–
Transportation and selling	**525**	472	429	**13**	18	47
Operating	**1,351**	1,026	872	**85**	74	93
Purchased product	**–**	–	–	**4,159**	3,092	2,572
Depreciation, depletion and amortization	**2,688**	2,271	1,900	**8**	47	26
Segment Income (Loss)	**$ 5,448**	$ 3,176	$ 2,432	**$ 2**	$ (31)	$ (16)

	Corporate 2005	Corporate 2004	Corporate 2003	Consolidated 2005	Consolidated 2004	Consolidated 2003
Revenues, Net of Royalties	**$ (466)**	$ (197)	$ 2	**$ 14,266**	$ 10,259	$ 8,521
Expenses						
Production and mineral taxes	**–**	–	–	**453**	311	164
Transportation and selling	**–**	–	–	**538**	490	476
Operating	**2**	(1)	–	**1,438**	1,099	965
Purchased product	**–**	–	–	**4,159**	3,092	2,572
Depreciation, depletion and amortization	**73**	61	41	**2,769**	2,379	1,967
Segment Income (Loss)	**$ (541)**	$ (257)	$ (39)	**4,909**	2,888	2,377
Administrative				**268**	197	173
Interest, net				**524**	398	284
Accretion of asset retirement obligation				**37**	22	17
Foreign exchange (gain) loss, net				**(24)**	(412)	(603)
Stock-based compensation – options				**15**	17	18
(Gain) on divestitures				**–**	(59)	(1)
				820	163	(112)
Net Earnings Before Income Tax				**4,089**	2,725	2,489
Income tax expense				**1,260**	632	351
Net Earnings From Continuing Operations				**$ 2,829**	$ 2,093	$ 2,138

Upstream

For the years ended December 31	Canada 2005	Canada 2004	Canada 2003	United States 2005	United States 2004	United States 2003
Revenues, Net of Royalties	**$ 7,005**	$ 5,083	$ 4,474	**$ 3,177**	$ 1,941	$ 1,143
Expenses						
Production and mineral taxes	**104**	87	56	**349**	224	108
Transportation and selling	**343**	352	343	**182**	120	86
Operating	**826**	685	642	**212**	119	60
Depreciation, depletion and amortization	**1,927**	1,751	1,511	**682**	475	293
Segment Income (Loss)	**$ 3,805**	$ 2,208	$ 1,922	**$ 1,752**	$ 1,003	$ 596

	Other 2005	Other 2004	Other 2003	Total Upstream 2005	Total Upstream 2004	Total Upstream 2003
Revenues, Net of Royalties	**$ 283**	$ 232	$ 180	**$ 10,465**	$ 7,256	$ 5,797
Expenses						
Production and mineral taxes	**–**	–	–	**453**	311	164
Transportation and selling	**–**	–	–	**525**	472	429
Operating	**313**	222	170	**1,351**	1,026	872
Depreciation, depletion and amortization	**79**	45	96	**2,688**	2,271	1,900
Segment Income (Loss)	**$ (109)**	$ (35)	$ (86)	**$ 5,448**	$ 3,176	$ 2,432

Upstream Geographic and Product Information (Continuing Operations)

	Produced Gas								
	Canada			United States			Total		
For the years ended December 31	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Revenues, Net of Royalties	**$5,486**	$3,928	$3,396	**$ 2,932**	$1,776	$1,051	**$8,418**	$5,704	$4,447
Expenses									
Production and mineral taxes	**76**	65	52	**325**	205	101	**401**	270	153
Transportation and selling	**283**	296	274	**182**	120	86	**465**	416	360
Operating	**521**	400	342	**212**	119	60	**733**	519	402
Operating Cash Flow	**$4,606**	$3,167	$2,728	**$2,213**	$1,332	$ 804	**$6,819**	$4,499	$3,532

	Oil and NGLs								
	Canada			United States			Total		
	2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Revenues, Net of Royalties	**$1,519**	$1,155	$1,078	**$ 245**	$ 165	$ 92	**$1,764**	$1,320	$1,170
Expenses									
Production and mineral taxes	**28**	22	4	**24**	19	7	**52**	41	11
Transportation and selling	**60**	56	69	**–**	–	–	**60**	56	69
Operating	**305**	285	300	**–**	–	–	**305**	285	300
Operating Cash Flow	**$1,126**	$ 792	$ 705	**$ 221**	$ 146	$ 85	**$1,347**	$ 938	$ 790

	Other			Total Upstream		
	2005	2004	2003	**2005**	2004	2003
Revenues, Net of Royalties	**$ 283**	$ 232	$ 180	**$10,465**	$7,256	$5,797
Expenses						
Production and mineral taxes	**–**	–	–	**453**	311	164
Transportation and selling	**–**	–	–	**525**	472	429
Operating	**313**	222	170	**1,351**	1,026	872
Operating Cash Flow	**$ (30)**	$ 10	$ 10	**$ 8,136**	$5,447	$4,332

Capital Expenditures (Continuing Operations)

For the years ended December 31	**2005**	2004	2003
Upstream Core Capital			
Canada	**$4,150**	$3,015	$2,937
United States	**1,982**	1,249	830
Other Countries	**70**	79	78
	6,202	4,343	3,845
Upstream Acquisition Capital			
Canada	**30**	64	261
United States	**418**	300	138
	448	364	399
Market Optimization	**197**	10	5
Corporate	**78**	46	107
Total	**$6,925**	$4,763	$4,356

On December 17, 2004, EnCana acquired certain natural gas and crude oil properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, Brown Ranger LLC, which held the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operated the properties, received all the revenue and paid all of the expenses associated with the properties. EnCana determined that the relationship with Brown Ranger LLC represented an interest in a variable interest entity ("VIE") and that EnCana was the primary beneficiary of the VIE. EnCana consolidated Brown Ranger LLC from the date of acquisition to the date the properties were transferred to EnCana in 2005.

Additions to Goodwill

There was no addition to goodwill during 2005 (2004 – $473 million as a result of the business combination with Tom Brown, Inc. (see Note 2)). All goodwill included in continuing operations relates to the Upstream segment.

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment		Total Assets	
As at December 31		**2005**	2004	**2005**	2004
Upstream		**$ 24,247**	$ 22,097	**$ 28,858**	$ 26,118
Market Optimization		**371**	167	**597**	414
Corporate		**263**	239	**1,530**	1,385
Assets of Discontinued Operations	(Note 4)			**3,163**	3,296
Total		**$ 24,881**	$ 22,503	**$ 34,148**	$ 31,213

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,784 million (2004 – $1,747 million; 2003 – $1,484 million).

Major Customers

In connection with the marketing and sale of EnCana's own and purchased natural gas and crude oil, for the year ended December 31, 2005, the Company had one customer (2004 – one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to this customer, a major international integrated energy company with a high quality investment grade credit rating, were approximately $2,056 million (2004 – $1,709 million).

4. Discontinued Operations

2005

Midstream

On December 13, 2005 EnCana completed the sale of its Midstream natural gas liquids processing operations for total proceeds of $625 million (C$720 million). The natural gas liquids processing operations included various interests in a number of processing and related facilities as well as a marketing entity. A gain on sale of approximately $370 million, after-tax, was recorded.

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana's natural gas storage operations include the 100 percent interest in the AECO storage facility as well as facilities in the United States.

2004

Upstream

On December 1, 2004, the Company completed the sale of its 100 percent interest in EnCana (U.K.) Limited for net cash consideration of approximately $2.1 billion. EnCana's U.K. operations included crude oil and natural gas interests in the U.K. central North Sea including the Buzzard, Scott and Telford oilfields, as well as other satellite discoveries and exploration licenses. A gain on sale of approximately $1.4 billion was recorded.

At December 31, 2004, EnCana decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. On September 13, 2005, EnCana announced it had reached an agreement in principle to sell all its interest in its Ecuador properties for $1.42 billion, which is approximately equivalent to the asset's net book value at July 1, 2005, the referenced effective date of the transaction.

Included in net earnings for the year is a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments, as required under Canadian generally accepted accounting principles.

EnCana's Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in relation to Block 15 and the 36.3 percent 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 an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. 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.

2003

Upstream

In 2003, in two separate transactions, the Company completed the sale of its 13.75 percent working interest and a gross overriding royalty in the Syncrude Joint Venture ("Syncrude") for net cash consideration of $999 million.

Midstream

In January 2003, EnCana closed the previously announced sales of its crude oil pipeline business resulting in an after-tax gain on sale of $169 million.

Consolidated Statement of Earnings

The following tables present the effect of the discontinued operations in the Consolidated Statement of Earnings:

Upstream – Ecuador

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ 965**	$ 471	$ 412
Expenses			
Production and mineral taxes	**131**	61	25
Transportation and selling	**58**	60	45
Operating	**138**	125	83
Depreciation, depletion and amortization	**234**	263	159
Interest, net	**(2)**	(3)	4
Accretion of asset retirement obligation	**1**	1	1
Foreign exchange (gain) loss	**(4)**	5	2
	556	512	319
Net Earnings (Loss) Before Income Tax	**409**	(41)	93
Income tax expense (recovery)	**278**	(8)	61
Net Earnings (Loss) From Discontinued Operations	**$ 131**	$ (33)	$ 32

Upstream – United Kingdom

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ –**	$ 153	$ 118
Expenses			
Transportation and selling	**–**	36	16
Operating	**–**	36	18
Depreciation, depletion and amortization	**–**	118	74
Interest, net	**–**	(9)	–
Accretion of asset retirement obligation	**–**	3	1
Foreign exchange (gain), net	**(40)**	(2)	(5)
(Gain) loss on discontinuance	**–**	(1,365)	1
	(40)	(1,183)	105
Net Earnings (Loss) Before Income Tax	**(40)**	1,336	13
Income tax expense (recovery)	**5**	(2)	20
Net Earnings (Loss) From Discontinued Operations	**$ 35**	$ 1,338	$ (7)

Upstream – Syncrude

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ –**	$ (1)	$ 87
Expenses			
Transportation and selling	**–**	—	2
Operating	**–**	—	46
Depreciation, depletion and amortization	**–**	—	7
Loss on discontinuance	**–**	2	—
	–	2	55
Net (Loss) Earnings Before Income Tax	**–**	(3)	32
Income tax expense	**–**	—	8
Net (Loss) Earnings From Discontinued Operations	**$ –**	$ (3)	$ 24

Midstream

For the years ended December 31	2005	2004	2003
Revenues	**$ 1,570**	$ 1,551	$ 1,165
Expenses			
Transportation and selling	**9**	9	8
Operating	**301**	251	231
Purchased product	**1,100**	1,184	883
Depreciation, depletion and amortization	**28**	23	22
Administrative	**30**	—	—
Interest, net	**(2)**	(1)	(1)
Foreign exchange (gain) loss, net	**(2)**	(5)	5
(Gain) on discontinuance	**(364)**	(54)	(220)
	1,100	1,407	928
Net Earnings Before Income Tax	**470**	144	237
Income tax expense	**39**	26	64
Net Earnings From Discontinued Operations	**$ 431**	$ 118	$ 173

Consolidated Total

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ 2,535**	$ 2,174	$ 1,782
Expenses			
Production and mineral taxes	**131**	61	25
Transportation and selling	**67**	105	71
Operating	**439**	412	378
Purchased product	**1,100**	1,184	883
Depreciation, depletion and amortization	**262**	404	262
Administrative	**30**	—	—
Interest, net	**(4)**	(13)	3
Accretion of asset retirement obligation	**1**	4	2
Foreign exchange (gain) loss, net	**(46)**	(2)	2
(Gain) on discontinuance	**(364)**	(1,417)	(219)
	1,616	738	1,407
Net Earnings Before Income Tax	**919**	1,436	375
Income tax expense	**322**	16	153
Net Earnings From Discontinued Operations	**$ 597**	$ 1,420	$ 222
Net Earnings from Discontinued Operations per Common Share			
Basic	**$ 0.69**	$ 1.55	$ 0.24
Diluted	**$ 0.67**	$ 1.51	$ 0.23

Consolidated Balance Sheet

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

As at December 31	2005	2004
Assets		
Cash and cash equivalents	**$ 208**	$ 23
Accounts receivable and accrued revenues	**408**	456
Risk management	**21**	22
Inventories	**413**	470
	1,050	971
Property, plant and equipment, net	**1,686**	1,932
Investments and other assets	**360**	328
Goodwill	**67**	65
	$ 3,163	$ 3,296
Liabilities		
Accounts payable and accrued liabilities	**$ 167**	$ 233
Income tax payable	**230**	103
Risk management	**41**	89
	438	425
Asset retirement obligation	**21**	22
Future income taxes	**246**	202
	705	649
Net Assets of Discontinued Operations	**$ 2,458**	$ 2,647

Included in Midstream is $117 million (2004 – $102 million; 2003 – $97 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

The prices used in the ceiling test evaluation of the Company's crude oil reserves in Ecuador at December 31, 2005 were as follows:

	2006	2007	2008	2009	2010	% increase to 2017
Crude Oil ($/barrel)	$ 42.70	$ 42.44	$ 40.92	$ 28.26	$ 28.13	13%

Acquisitions/Divestitures

On December 22, 2004 EnCana completed the divestiture of its interest in the Alberta Ethane Gathering System Joint Venture for approximately $108 million, including working capital. A $54 million pre-tax gain was recorded on this sale.

On January 31, 2003, the Company acquired the Ecuador interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $116 million. During the fourth quarter of 2003, the Company disposed of its interest in Block 27 in Ecuador for approximately $14 million.

Commitments and Contingencies

The Company is a shipper on the OCP Pipeline and has tariff commitments as follows:

As at December 31, 2005	2006	2007	2008	2009	2010	Thereafter	Total
Pipeline Transportation	$ 89	$ 91	$ 93	$ 95	$ 97	$ 827	$ 1,292

In Ecuador, a subsidiary of EnCana has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. In its 2004 filings with Securities regulatory authorities, Occidental Petroleum Corporation indicated that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its filings, Occidental Petroleum Corporation indicated that it believes that it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties. The subsidiary of Occidental Petroleum Corporation has delivered, to the Government of Ecuador, its written defense to the allegations. Upon review the Government of Ecuador may decide whether there are grounds for termination of the Participation Contract.

In addition to the above, the Company is proceeding with its arbitration related to value-added tax ("VAT") owed to subsidiaries of EnCana ($169 million at December 31, 2005; 2004 – $139 million). EnCana is also in discussions related to certain income tax matters related to the deductibility of interest expense and foreign currency losses in Ecuador.

5. Divestitures (Acquisitions)

For the years ended December 31	2005	2004	2003
Upstream	**$ 2,521**	$ 1,430	$ 210
Market Optimization	**—**	26	—
Other	**2**	44	—
	$ 2,523	$ 1,500	$ 210

Proceeds received on the sale of assets and investments in 2005 were $2,523 million (2004 – $1,500 million) as described below:

Upstream

In 2005, EnCana completed the disposition of various mature conventional oil and natural gas assets for proceeds of $471 million (2004 – $1,430 million; 2003 – $301 million).

In May 2005, EnCana completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $578 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

On July 18, 2003 EnCana acquired the common shares of Savannah Energy Inc.("Savannah") for net cash consideration of $91 million. Savannah's operations are located in Texas, U.S.A.

Market Optimization

On December 15, 2004, EnCana sold its 25 percent limited partnership interest in the Kingston CoGen Limited Partnership ("Kingston") for net cash consideration of $25 million. A pre-tax gain of $28 million was recorded on this sale.

Other

In March 2004, the Company sold its equity investment in a well servicing company for approximately $44 million, recording a pre-tax gain on sale of $34 million.

6. Interest, Net

For the years ended December 31	2005	2004	2003
Interest Expense – Long-Term Debt	**$ 417**	$ 385	$ 281
Early Retirement of Long-Term Debt	**121**	(16)	—
Interest Expense – Other	**18**	42	20
Interest Income	**(32)**	(13)	(17)
	$ 524	$ 398	$ 284

During 2005, EnCana redeemed a number of unsecured notes with a principal of C$1,150 million. The $121 million before tax ($79 million after-tax) charge is due to the early retirement of these medium term notes (see Note 12).

EnCana 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 detailed below (see Note 12). The net effect of these transactions reduced interest costs in 2005 by $16 million (2004 – $22 million; 2003 – $23 million).

Swap Positions As at December 31, 2005	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
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

* These instruments have been subject to multiple swap transactions.

7. Foreign Exchange (Gain) Loss, Net

For the years ended December 31	2005	2004	2003
Unrealized Foreign Exchange Gain on Translation of U.S. Dollar Debt Issued in Canada	**$ (113)**	$ (285)	$ (545)
Other Foreign Exchange Loss (Gain)	**89**	(127)	(58)
	$ (24)	$ (412)	$ (603)

8. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31	2005	2004	2003
Current			
Canada	**$ 493**	$ 586	$ (142)
United States	**719**	(12)	39
Other	**(8)**	(15)	(16)
Total Current Tax	**1,204**	559	(119)
Future	**56**	182	829
Future Tax Rate Reductions	**—**	(109)	(359)
Total Future Tax	**56**	73	470
	$ 1,260	$ 632	$ 351

Included in cash tax for 2005 is $578 million related to the sale of the Gulf of Mexico assets.

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

For the years ended December 31	2005	2004	2003
Net Earnings Before Income Tax	**$ 4,089**	$ 2,725	$ 2,489
Canadian Statutory Rate	**37.9%**	39.1%	41.0%
Expected Income Tax	**1,550**	1,066	1,020
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	**207**	192	231
Canadian resource allowance	**(202)**	(246)	(258)
Canadian resource allowance on unrealized risk management losses	**—**	(10)	—
Statutory and other rate differences	**(235)**	(50)	(44)
Effect of tax rate changes	**—**	(109)	(359)
Non-taxable capital gains	**(24)**	(91)	(119)
Previously unrecognized capital losses	**—**	17	(119)
Tax basis retained on dispositions	**(68)**	(169)	—
Large corporations tax	**25**	24	27
Other	**7**	8	(28)
	$ 1,260	$ 632	$ 351
Effective Tax Rate	**30.8%**	23.2%	14.1%

The net future income tax liability is comprised of:

As at December 31	2005	2004
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,461**	$ 4,390
Timing of Partnership items	**1,226**	975
Future Tax Assets		
Net operating losses carried forward	**(47)**	(103)
Other	**(351)**	(180)
Net Future Income Tax Liability	**$ 5,289**	$ 5,082

The approximate amounts of tax pools available are as follows:

As at December 31	2005	2004
Canada	**$ 8,575**	$ 7,034
United States	**2,978**	2,760
	$ 11,553	$ 9,794

Included in the above tax pools are $133 million (2004 – $275 million) related to non-capital or net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2008 and 2023.

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 year end that is after that of EnCana Corporation.

9. Inventories

As at December 31	2005	2004
Product		
Upstream	**$ 70**	$ 14
Market Optimization	**31**	42
Parts and Supplies	**2**	2
	$ 103	$ 58

10. Property, Plant and Equipment, Net

As at December 31	2005			2004		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream						
Canada	**$ 29,199**	**$(12,144)**	**$ 17,055**	$ 24,390	$ (9,775)	$ 14,615
United States	**8,707**	**(1,763)**	**6,944**	8,360	(1,056)	7,304
Other Countries	**470**	**(222)**	**248**	425	(247)	178
Total Upstream	**38,376**	**(14,129)**	**24,247**	33,175	(11,078)	22,097
Market Optimization	**419**	**(48)**	**371**	208	(41)	167
Corporate	**544**	**(281)**	**263**	455	(216)	239
	$ 39,339	**$(14,458)**	**$ 24,881**	$ 33,838	$(11,335)	$ 22,503

* Depreciation, depletion and amortization

Included in property, plant and equipment are asset retirement costs, net of amortization, of $498 million (2004 – $393 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 at the end of the year were:

As at December 31	2005	2004	2003
Canada	**$ 1,689**	$ 1,444	$ 1,444
United States	**870**	1,119	499
Other Countries	**248**	177	112
	$ 2,807	$ 2,740	$ 2,055

The costs excluded from depletable costs in Other Countries represents 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. For the year ended December 31, 2005, the Company completed its impairment review of pre-production cost centres and determined that $7 million of costs should be charged to the Consolidated Statement of Earnings (2004 – $23 million; 2003 – $85 million).

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2005 were:

	2006	2007	2008	2009	2010	% increase to 2017
Natural Gas ($/Mcf)						
Canada	$ 9.42	$ 8.42	$ 7.35	$ 4.87	$ 4.84	17%
United States	$ 9.92	$ 8.59	$ 7.51	$ 5.30	$ 5.29	12%
Crude Oil ($/barrel)						
Canada	$ 34.50	$ 33.11	$ 31.61	$ 21.75	$ 21.57	8%
Natural Gas Liquids ($/barrel)						
Canada	$ 55.92	$ 56.21	$ 53.25	$ 36.11	$ 36.14	17%
United States	$ 53.92	$ 53.36	$ 52.04	$ 34.68	$ 34.24	15%

11. Investments and Other Assets

As at December 31	2005	2004
Equity Investments	$ 7	$ 8
Marketing Contracts	10	12
Deferred Financing Costs	59	61
Deferred Pension Plan and Savings Plan	60	64
Prepaid Capital	334	160
Other	26	29
	$ 496	$ 334

12. Long-Term Debt

As at December 31	Note	2005	2004
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	B	$ 1,425	$ 1,515
Unsecured notes	C	793	1,309
		2,218	2,824
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	D	–	399
Unsecured notes and debentures	E	4,494	4,641
		4,494	5,040
Increase in Value of Debt Acquired	F	64	66
Current Portion of Long-Term Debt	G	(73)	(188)
		$ 6,703	$ 7,742

A) Overview

Revolving Credit and Term Loan Borrowings

At December 31, 2005, EnCana Corporation had in place a revolving credit facility for $4.5 billion Canadian dollars or its equivalent amount in U.S. dollars ($3.9 billion). The facility is fully revolving for a period of five years from the date of the agreement, October 2005. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years from the extension date, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders' rates for Canadian prime, U.S. base rate, Bankers' Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2005, one of EnCana's subsidiaries had in place a credit facility totaling $600 million. The facility is guaranteed by EnCana Corporation and fully revolving for five years from the date of the Agreement, December, 2005. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years from the extension date, 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.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper of $1,425 million (2004 – $1,559 million) maturing at various dates with a weighted average interest rate of 3.52% (2004 – 2.83%). There were no LIBOR loans outstanding at December 31, 2005 (2004 – $355 million with a weighted average interest rate of 2.98%). 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 2005 relating to revolving credit and term loan agreements were approximately $4 million (2004 – $5 million; 2003 – $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 C$1 billion medium term note program was renewed in 2005 with C$500 million ($429 million) unutilized at December 31, 2005. The current shelf prospectus expires in 2007. The notes issued under this program may be denominated in Canadian dollars or in foreign currencies.

EnCana has in place a shelf prospectus for U.S. Unsecured Notes in the amount of $2 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, 2005, $2 billion of the shelf prospectus, which expires in 2006, remains unutilized.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a shelf prospectus in the amount of $2 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. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. At December 31, 2005, $1 billion of the shelf prospectus, which expires in 2006, remains unutilized.

B) Canadian Revolving Credit and Term Loan Borrowings

	C$ Principal Amount	2005	2004
Bankers' Acceptances	$ 430	$ 369	$ 511
Commercial Paper	1,231	1,056	1,004
	$ 1,661	$ 1,425	$ 1,515

C) Canadian Unsecured Notes

	C$ Principal Amount	2005	2004
5.95% due October 1, 2007	$ —	$ —	$ 166
5.30% due December 3, 2007	300	257	248
5.95% due June 2, 2008	—	—	83
5.80% due June 2, 2008	125	107	104
5.80% due June 19, 2008	—	—	83
3.60% due September 15, 2008	500	429	—
6.10% due June 1, 2009	—	—	125
7.15% due December 17, 2009	—	—	125
8.50% due March 15, 2011	—	—	42
7.10% due October 11, 2011	—	—	166
7.30% due September 2, 2014	—	—	125
6.20% due June 23, 2028	—	—	42
	$ 925	$ 793	$ 1,309

During the third quarter of 2005, EnCana redeemed a number of unsecured medium term notes with a total principal of C$1,150 (Note 6).

D) U.S. Revolving Credit and Term Loan Borrowings

	2005	2004
Commercial Paper	$ —	$ 44
LIBOR Loan	—	355
	$ —	$ 399

E) U.S. Unsecured Notes and Debentures

	C$ Amount	2005	2004
Floating Rate			
8.75% due November 9, 2005	$ —	$ —	$ 73
Fixed Rate			
8.75% due November 9, 2005		—	73
7.50% due August 25, 2006	85*	73	73
5.80% due June 2, 2008	83*	71	71
4.60% due August 15, 2009		250	250
7.65% due September 15, 2010		200	200
6.30% due November 1, 2011		500	500
7.25% due September 15, 2013		—	1
4.75% due October 15, 2013		500	500
5.80% due May 1, 2014		1,000	1,000
8.125% due September 15, 2030		300	300
7.20% due November 1, 2031		350	350
7.375% due November 1, 2031		500	500
6.50% due August 15, 2034		750	750
		$ 4,494	$ 4,641

* 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.

The 5.80% Notes due May 1, 2014 were issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. These notes are fully and unconditionally guaranteed by EnCana Corporation.

F) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in business combinations 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 21 years.

G) Current Portion of Long-Term Debt

	2005	2004
6.20% Medium Term Note due June 23, 2028	$ —	$ 42
8.75% Unsecured Note due November 9, 2005	—	146
7.50% Medium Term Note due August 25, 2006	73	—
	$ 73	$ 188

H) Mandatory Debt Payments

	C$ Principal Amount	US$ Principal Amount	**Total US$ Equivalent**
2006	$ —	$ 73	**$ 73**
2007	300	—	**257**
2008	625	71	**607**
2009	—	250	**250**
2010	—	200	**200**
Thereafter	1,661	3,900	**5,325**
Total	$ 2,586	$ 4,494	**$ 6,712**

The amount due in 2006 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.

13. 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	**2005**	2004
Asset Retirement Obligation, Beginning of Year	**$ 611**	$ 383
Liabilities Incurred	**77**	98
Liabilities Settled	**(42)**	(16)
Liabilities Disposed	**(23)**	(35)
Change in Estimated Future Cash Flows	**135**	124
Accretion Expense	**37**	22
Other	**21**	35
Asset Retirement Obligation, End of Year	**$ 816**	$ 611

The total undiscounted amount of estimated cash flows required to settle the obligation is $4,944 million (2004 – $3,695 million), which has been discounted using a weighted average credit-adjusted risk free rate of 5.74 percent (2004 – 5.94 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 that time.

14. 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

As at December 31	**2005**		2004	
	Number (millions)	**Amount**	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**900.6**	**$ 5,299**	921.2	$ 5,305
Common Shares Issued under Option Plans	**15.0**	**294**	19.4	281
Common Shares Repurchased	**(60.7)**	**(462)**	(40.0)	(287)
Common Shares Outstanding, End of Year	**854.9**	**$ 5,131**	900.6	$ 5,299

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

Normal Course Issuer Bid

In 2005, the Company purchased 60,757,198 Common Shares for total consideration of $2,114 million. Of the amount paid, $462 million was charged to Share capital, $10 million was charged to Paid in surplus and $1,642 million was charged to Retained earnings. Included in the above are 5.5 million Common Shares which have been purchased by an EnCana Employee Benefit Plan Trust and are held for issuance upon vesting of units under EnCana's Performance Share Unit Plan (see Note 15).

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under four consecutive Normal Course Issuer Bids ("Bids") which commenced in October 2002 and may continue up to October 30, 2006. EnCana is entitled to purchase, for cancellation, up to approximately 85.6 million Common Shares under the current Bid. During January 2006, EnCana purchased approximately 6.8 million Common Shares under the Bid for total consideration of $314 million. Under the prior Bid, which ran from October 29, 2004 until October 28, 2005, EnCana purchased approximately 84.2 million Common Shares.

Stock Options

EnCana has stock-based compensation plans that allow employees and directors 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 plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to ten years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right ("TSAR") attached to them (see Note 15).

In conjunction with the business combination transaction with Alberta Energy Company Ltd. ("AEC") in 2002, 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 then 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 EnCana Common Shares. 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 ten 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.

Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited ("CPL"), EnCana's former parent company, 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 ten 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 and on October 25, 2005 the Corporation terminated the plan.

The following tables summarize the information about options to purchase Common Shares that have no TSAR attached to them:

	2005		2004		2003	
As at December 31	**Stock Options (millions)**	**Weighted Average Exercise Price (C$)**	Stock Options (millions)	Weighted Average Exercise Price (C$)	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	**36.2**	**23.15**	57.6	21.57	59.2	19.87
Granted under EnCana Plan	**—**	**—**	—	—	12.6	23.99
Granted under Directors' Plan	**—**	**—**	—	—	0.2	23.94
Exercised	**(14.9)**	**22.90**	(19.4)	18.32	(11.0)	14.56
Forfeited	**(0.6)**	**21.71**	(2.0)	23.75	(3.4)	20.59
Outstanding, End of Year	**20.7**	**23.36**	36.2	23.15	57.6	21.57
Exercisable, End of Year	**16.8**	**23.21**	21.6	22.55	31.2	19.46

As at December 31, 2005	**Outstanding Options**			**Exercisable Options**	
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$)**
10.50 to 22.99	**1.7**	**2.3**	**15.74**	**1.7**	**15.60**
23.00 to 23.49	**1.3**	**0.7**	**23.17**	**1.1**	**23.16**
23.50 to 23.99	**6.9**	**2.3**	**23.89**	**3.6**	**23.88**
24.00 to 24.49	**10.2**	**1.2**	**24.18**	**10.1**	**24.18**
24.50 to 25.99	**0.6**	**2.6**	**25.23**	**0.3**	**25.21**
	20.7	**1.7**	**23.36**	**16.8**	**23.21**

At December 31, 2005, there were 29.3 million common shares reserved for issuance under stock option plans (2004 – 16.0 million; 2003 – 15.6 million).

EnCana has 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. Stock options granted subsequent to December 31, 2003 have an associated TSAR attached. 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 2005 would have been unchanged (2004 – $3,476 million; $3.77 per common share – basic; $3.71 per common share – diluted).

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

For the year ended December 31	2003
Weighted Average Fair Value of Options Granted (C$)	$ 6.11
Risk-Free Interest Rate	3.87%
Expected Lives (years)	3.00
Expected Volatility	0.33
Annual Dividend per Share (C$/common share)	$ 0.20

At December 31, 2005 the balance in Paid in surplus relates to Stock Based Compensation programs.

15. Compensation Plans

Where applicable, the amounts below have been restated to reflect the effect of the common share split approved in April 2005.

A) Pensions and Post-Employment Benefits

The most recent actuarial valuation completed for the Company's pension plans is dated December 31, 2004. The next required valuation will be as at December 31, 2007.

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

For the years ended December 31	2005	2004	2003
Total Expense for Defined Contribution Plans	**$ 22**	$ 19	$ 12

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

	Pension Benefits		OPEB	
As at December 31	2005	2004	2005	2004
Accrued Benefit Obligation, Beginning of Year	**$ 246**	$ 214	**$ 19**	$ 14
Beginning of year adjustment	**—**	(1)	**—**	—
Amendments	**—**	—	**13**	—
Current service cost	**6**	5	**5**	1
Interest cost	**14**	13	**2**	1
Benefits paid	**(12)**	(10)	**(1)**	—
Actuarial loss	**29**	8	**—**	1
Contributions	**1**	1	**—**	—
Foreign exchange	**10**	16	**1**	2
Accrued Benefit Obligation, End of Year	**$ 294**	$ 246	**$ 39**	$ 19

The amendments made January 1, 2005 relate to obligations for OPEB related to the acquisition of TBI and changes made to one of the Company's Plans which increased the Company's post-employment benefit obligation.

	Pension Benefits		OPEB	
As at December 31	2005	2004	2005	2004
Fair Value of Plan Assets, Beginning of Year	**$ 247**	$ 203	**$ —**	$ —
Actual return on plan assets	**29**	19	**—**	—
Employer contributions	**9**	17	**—**	—
Employees' contributions	**1**	1	**—**	—
Benefits paid	**(12)**	(10)	**—**	—
Foreign exchange	**10**	17	**—**	—
Fair Value of Plan Assets, End of Year	**$ 284**	$ 247	**$ —**	$ —

	Pension Benefits		OPEB	
As at December 31	2005	2004	2005	2004
Funded Status – Plan Assets (less) than Benefit Obligation	**$ (10)**	$ 1	**$ (39)**	$ (19)
Amounts Not Recognized:				
Unamortized net actuarial loss	**64**	54	**4**	4
Unamortized past service cost	**9**	10	**1**	2
Net transitional asset	**(8)**	(11)	**14**	2
Accrued Benefit Asset (Liability)	**$ 55**	$ 54	**$ (20)**	$ (11)

	Pension Benefits		OPEB	
As at December 31	**2005**	2004	**2005**	2004
Prepaid Benefit Cost	**$ 55**	$ 54	**$ —**	$ —
Accrued Benefit Cost	**—**	—	**(20)**	(11)
Net Amount Recognized	**$ 55**	$ 54	**$ (20)**	$ (11)

The Company's other post employment benefit plans are funded on an as required basis.

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

	Pension Benefits		OPEB	
As at December 31	**2005**	2004	**2005**	2004
Discount Rate	**5.00%**	5.75%	**5.25%**	5.75%
Rate of Compensation Increase	**4.50%**	4.60%	**5.65%**	5.65%

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

	Pension Benefits		OPEB	
For the years ended December 31	**2005**	2004	**2005**	2004
Discount Rate	**5.75%**	6.00%	**5.75%**	6.00%
Expected Long-Term Rate of Return on Plan Assets				
Registered pension plans	**6.75%**	6.75%	**n/a**	n/a
Supplemental pension plans	**3.375%**	3.375%	**n/a**	n/a
Rate of Compensation Increase	**4.60%**	4.75%	**5.65%**	5.75%

The periodic expense for benefits is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2005**	2004	2003	**2005**	2004	2003
Current Service Cost	**$ 6**	$ 5	$ 5	**$ 5**	$ 1	$ 1
Interest Cost	**14**	13	11	**2**	1	1
Actual Return on Plan Assets	**(29)**	(19)	(16)	**—**	—	—
Actuarial Loss on Accrued Benefit Obligation	**29**	8	12	**—**	1	1
Plan Amendment	**—**	—	—	**—**	—	2
Difference Between Actual and:						
Expected return on plan assets	**15**	7	7	**—**	—	—
Recognized actuarial loss	**(24)**	(4)	(8)	**—**	(1)	(1)
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	1	**—**	—	(2)
Amortization of Transitional Obligation	**(3)**	(2)	(2)	**1**	—	—
Expense for Defined Contribution Plan	**22**	19	12	**—**	—	—
Net Benefit Plan Expense	**$ 32**	$ 29	$ 22	**$ 8**	$ 2	$ 2

The average remaining service period of the active employees covered by the defined benefit pension plan is seven years. The average remaining service period of the active employees covered by the other retirement benefits plan is 12 years.

Assumed health care cost trend rates are as follows:

As at December 31	**2005**	2004
Health Care Cost Trend Rate for Next Year	**11.00%**	10.00%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2015**	2015

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	$ 1	$ (1)
Effect on Post Retirement Benefit Obligation	$ 4	$ (3)

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

Asset Category	Target Allocation %		% of Plan Assets at December 31		Expected Long-Term Rate of Return
	Normal	Range	**2005**	2004	
Domestic Equity	35	25-45	**41**	38	
Foreign Equity	30	20-40	**27**	28	
Bonds	30	20-40	**25**	27	
Real Estate and Other	5	0-20	**7**	7	
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 Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

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.

Management expects to contribute $10 million to the plans in 2006. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2005 (2004 – $1 million; 2003 – $1 million).

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

	Pension Benefits	OPEB
2006	$ 13	$ 1
2007	14	1
2008	15	2
2009	16	2
2010	16	2
2011 – 2015	96	23
Total	$ 170	$ 31

B) Share Appreciation Rights

EnCana 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 EnCana'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	2005 Outstanding SAR's	2005 Weighted Average Exercise Price	2004 Outstanding SAR's	2004 Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**930,510**	**18.31**	2,350,140	17.94
Exercised	**(682,241)**	**16.55**	(1,397,550)	17.74
Forfeited	**(1,530)**	**23.14**	(22,080)	14.63
Outstanding, End of Year	**246,739**	**23.13**	930,510	18.31
Exercisable, End of Year	**246,739**	**23.13**	930,510	18.31
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**771,860**	**14.40**	1,506,834	14.49
Exercised	**(452,349)**	**14.45**	(731,294)	14.60
Forfeited	**—**	**—**	(3,680)	12.65
Outstanding, End of Year	**319,511**	**14.33**	771,860	14.40
Exercisable, End of Year	**319,511**	**14.33**	771,860	14.40

As at December 31, 2005 Range of Exercise Price	SAR's Outstanding and Exercisable Number of SAR's	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)			
20.00 to 29.99	**246,739**	**0.19**	**23.13**
	246,739	**0.19**	**23.13**
U.S. Dollar Denominated (US$)			
10.00 to 19.99	**319,511**	**0.32**	**14.33**
	319,511	**0.32**	**14.33**

During the year, the Company recorded compensation costs of $17 million related to the outstanding SAR's (2004 – $17 million; 2003 – $12 million).

C) Tandem Share Appreciation Rights

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 14 have an associated Tandem Share Appreciation Right ("TSAR") attached to them whereby the option holder has the right to receive cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSAR's vest and expire under the same terms and conditions as the underlying option.

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

As at December 31	2005 Outstanding TSAR's	2005 Weighted Average Exercise Price	2004 Outstanding TSAR's	2004 Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**1,735,000**	**27.77**	—	—
Granted	**7,581,412**	**40.14**	2,160,900	27.66
Exercised – SARs	**(151,610)**	**27.51**	—	—
Exercised – Options	**(104,735)**	**27.60**	—	—
Forfeited	**(656,100)**	**34.44**	(425,900)	27.19
Outstanding, End of Year	**8,403,967**	**38.41**	1,735,000	27.77
Exercisable, End of Year	**229,705**	**28.00**	—	—

As at December 31, 2005	Outstanding TSAR's			Exercisable Options with TSAR's Attached	
Range of Exercise Price (C$)	Number of TSAR's	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSAR's	Weighted Average Exercise Price
20.00 to 29.99	**1,108,250**	**3.35**	**27.38**	**198,670**	**27.44**
30.00 to 39.99	**6,198,717**	**4.12**	**38.08**	**31,035**	**31.55**
40.00 to 49.99	**417,750**	**4.37**	**44.12**	**—**	**—**
50.00 to 59.99	**606,150**	**4.74**	**54.83**	**—**	**—**
60.00 to 69.99	**73,100**	**4.74**	**64.21**	**—**	**—**
	8,403,967	**4.08**	**38.41**	**229,705**	**28.00**

During the year, the Company recorded compensation costs of $60 million related to the outstanding TSAR's (2004 – $3 million).

D) 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 2002 vest over a three year period. DSU's expire on December 15th of the year following the employee's retirement or death.

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

	2005		2004	
As at December 31	Outstanding DSU's	Average Share Price	Outstanding DSU's	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**750,612**	**24.81**	638,500	24.34
Granted, Directors	**80,765**	**43.75**	117,862	27.02
Units, in Lieu of Dividends	**5,184**	**52.34**	6,416	29.93
Exercised	**—**	**—**	(12,166)	24.34
Outstanding, End of Year	**836,561**	**26.81**	750,612	24.81
Exercisable, End of Year	**836,561**	**26.81**	587,910	26.28

During the year, the Company recorded compensation costs of $16 million related to the outstanding DSU's (2004 – $10 million; 2003 – $4 million).

E) Performance Share Units

EnCana has in place a program whereby employees may be granted Performance Share Units ("PSU's") which entitle the employee to receive, upon vesting, either a common share of EnCana or a cash payment equal to the value of one common share of EnCana depending upon the terms of the PSU granted. PSU's vest at the end of a three year period. Their ultimate value will depend upon EnCana's performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed North American oil and gas comparison group. If EnCana's performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana's performance is at or above the specified level compared to 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 for PSU's granted for the 2003 grant and one half to two times the PSU's granted for the 2004 and 2005 grant.

PSU's granted subsequent to 2003 are to be paid in common shares (2003 – paid in cash).

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

As at December 31	2005 Outstanding PSU's	2005 Average Share Price	2004 Outstanding PSU's	2004 Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**3,294,206**	**26.71**	252,566	23.26
Granted	**1,734,089**	**38.13**	3,381,580	26.98
Forfeited	**(323,947)**	**30.48**	(339,940)	26.76
Outstanding, End of Year	**4,704,348**	**30.65**	3,294,206	26.71
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**449,230**	**20.56**	—	—
Granted	**390,171**	**30.92**	500,448	20.56
Forfeited	**(99,752)**	**26.50**	(51,218)	20.56
Outstanding, End of Year	**739,649**	**25.22**	449,230	20.56

During the year, the Company recorded compensation costs of $91 million related to the outstanding PSU's (2004 – $25 million; 2003 – $1 million).

At December 31, 2005, EnCana had approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU's.

16. Financial Instruments and Risk Management

As a means of managing commodity price volatility, EnCana has entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

The following table summarizes the realized and unrealized gains and losses on risk management activities:

	Realized Gain (Loss)		
As at December 31	**2005**	2004	2003
Revenues, Net of Royalties	**$ (684)**	$ (662)	$ (318)
Operating Expenses and Other	**31**	28	34
Loss on Risk Management – Continuing Operations	**(653)**	(634)	(284)
Loss on Risk Management – Discontinued Operations	**(126)**	(410)	(20)
	$ (779)	$ (1,044)	$ (304)

	Unrealized Gain (Loss)		
As at December 31	**2005**	2004	2003
Revenues, Net of Royalties	**$ (466)**	$ (198)	$ —
Operating Expenses and Other	**(3)**	7	—
Loss on Risk Management – Continuing Operations	**(469)**	(191)	—
Gain (Loss) on Risk Management – Discontinued Operations	**50**	(70)	—
	$ (419)	$ (261)	$ —

Amounts Recognized on Transition

Upon initial adoption of the current accounting policy for risk management instruments on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount (the "transition amount"). The transition amount is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with the associated unrealized gain or loss recorded in net earnings.

At December 31, 2005, a net unrealized gain remains to be recognized over the next three years as follows:

	Unrealized Gain
2006	
Three months ended March 31	$ 4
Three months ended June 30	7
Three months ended September 30	7
Three months ended December 31	6
Total to be recognized in 2006	$ 24
2007	15
2008	1
Total to be recognized in 2007 through to 2008	16
Total to be recognized	$ 40

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts during 2005:

	Net Deferred Amounts Recognized on Transition	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts and Premiums Paid, Beginning of Year	**$ (72)**	**$ (189)**	**$ –**
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2005	**–**	**(1,230)**	**(1,230)**
Fair Value of Contracts in Place at Transition Expired During 2005	**32**	**–**	**32**
Fair Value of Contracts Realized During 2005	**–**	**779**	**779**
Fair Value of Contracts Outstanding	**$ (40)**	**$ (640)**	**$ (419)**
Unamortized Premiums Paid on Collars and Options		**316**	
Fair Value of Contracts and Premiums Paid, End of Year		**$ (324)**	
Amounts Allocated to Continuing Operations	**$ (40)**	**$ (304)**	**$ (469)**
Amounts Allocated to Discontinued Operations	**–**	**(20)**	**50**
	$ (40)	**$ (324)**	**$ (419)**

At December 31, 2005, the remaining net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

As at December 31	2005
Remaining Deferred Amount Recognized on Transition	
Accounts receivable and accrued revenues	**$ 1**
Investments and other assets	**1**
Accounts payable and accrued liabilities	**25**
Other liabilities	**17**
Net Deferred Gain – Continuing Operations	**$ 40**

As at December 31	2005	2004
Risk Management		
Current asset	**$ 495**	$ 317
Long-term asset	**530**	87
Current liability	**1,227**	224
Long-term liability	**102**	192
Net Risk Management Liability – Continuing Operations	**(304)**	(12)
Net Risk Management Liability – Discontinued Operations	**(20)**	(67)
	$ (324)	$ (79)

A summary of all unrealized estimated fair value financial positions is as follows:

As at December 31	Note	2005	2004
Commodity Price Risk	A		
Natural gas		$ (247)	$ 105
Crude oil		(66)	(143)
Power		—	2
Credit Derivatives	C	(1)	—
Interest Rate Risk	B	10	24
Total Fair Value Positions – Continuing Operations		(304)	(12)
Total Fair Value Positions – Discontinued Operations		(20)	(67)
		$ (324)	$ (79)

A) Commodity Price Risk

Natural Gas

At December 31, 2005 the Company's gas risk management activities from financial contracts had an unrealized loss of $(500) million and a fair market value position of $(267) million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Term	Average Price	Fair Market Value
Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	525	2006	5.65 US$/Mcf	$ (954)
Colorado Interstate Gas (CIG)	100	2006	4.44 US$/Mcf	(151)
Houston Ship Channel (HSC)	90	2006	5.08 US$/Mcf	(146)
Other	81	2006	4.58 US$/Mcf	(126)
NYMEX Fixed Price	240	2007	7.76 US$/Mcf	(203)
Collars and Other Options				
Purchased NYMEX Put Options	2,602	2006	7.76 US$/Mcf	(73)
Purchased NYMEX Put Options	240	2007	6.00 US$/Mcf	(5)
Basis Contracts				
Fixed NYMEX to AECO basis	799	2006	(0.69) US$/Mcf	217
Fixed NYMEX to Rockies basis	324	2006	(0.58) US$/Mcf	162
Fixed NYMEX to CIG basis	301	2006	(0.83) US$/Mcf	133
Other	182	2006	(0.36) US$/Mcf	52
Fixed Rockies to CIG basis	12	2007	(0.10) US$/Mcf	—
Fixed NYMEX to AECO basis	735	2007	(0.71) US$/Mcf	101
Fixed NYMEX to Rockies basis	538	2007	(0.65) US$/Mcf	232
Fixed NYMEX to CIG basis	390	2007	(0.76) US$/Mcf	164
Fixed NYMEX to AECO basis	191	2008	(0.78) US$/Mcf	12
Fixed NYMEX to Rockies basis	162	2008	(0.59) US$/Mcf	52
Fixed NYMEX to CIG basis	40	2008-2009	(0.68) US$/Mcf	23
Purchase Contracts				
Fixed Price Contract – Waha Purchase	23	2006	5.32 US$/Mcf	33
				(477)
Gas Storage Optimization Financial Positions				(20)
Gas Marketing Financial Positions (1)				(3)
Total Unrealized Loss on Financial Contracts				(500)
Unamortized Premiums Paid on Options				233
Total Fair Value Positions				$ (267)
Total Fair Value Positions – Continuing Operations				(247)
Total Fair Value Positions – Discontinued Operations				(20)
Total Fair Value Positions				$ (267)

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

Crude Oil

As at December 31, 2005, the Company's oil risk management activities from all financial contracts had an unrealized loss of $(149) million and a fair market value position of $(66) million. The contracts were as follows:

	Notional Volumes (bbls/d)	Term	Average Price	**Fair Market Value**
Fixed WTI NYMEX Price	15,000	2006	34.56 US$/bbl	**$ (153)**
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75 US$/bbl	**5**
Purchased WTI NYMEX Put Options	57,000	2006	50.00 US$/bbl	**(10)**
Purchased WTI NYMEX Call Options	(13,700)	2006	61.24 US$/bbl	**14**
Purchased WTI NYMEX Put Options	43,000	2007	44.44 US$/bbl	**(6)**
				(150)
Other Financial Positions [1]				**1**
Total Unrealized Loss on Financial Contracts				**(149)**
Unamortized Premiums Paid on Options				**83**
Total Fair Value Positions				**$ (66)**
Total Fair Value Positions – Continuing Operations				**$ (66)**
Total Fair Value Positions – Discontinued Operations				**—**
				$ (66)

(1) Other financial positions are part of the daily ongoing operations of the Company's proprietary production management.

B) 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 6.

The unrealized gains on the outstanding financial instruments were as follows:

	Unrealized Gain	
As at December 31	**2005**	2004
5.80% Medium Term Notes	**$ 7**	$ 11
7.50% Medium Term Notes	**3**	5
8.75% Debenture	**—**	8
	$ 10	$ 24

At December 31, 2005, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $10 million (2004 – $13 million).

C) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments not recorded at their fair values 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	**2005**		2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	**$ 105**	**$ 105**	$ 593	$ 593
Accounts receivable	**1,851**	**1,851**	1,566	1,566
Financial Liabilities				
Accounts payable, income taxes payable	**$ 3,133**	**$ 3,133**	$ 2,099	$ 2,099
Long-term debt	**6,776**	**7,180**	7,930	8,479

D) 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 and net settlements where appropriate. At December 31, 2005, EnCana has three counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

17. 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	2005	2004	2003
Weighted Average Common Shares Outstanding – Basic	**868.3**	920.8	948.2
Effect of Stock Options and Other Dilutive Securities	**20.9**	15.2	11.2
Weighted Average Common Shares Outstanding – Diluted	**889.2**	936.0	959.4

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

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

For the years ended December 31	2005	2004	2003
Operating Activities			
Accounts receivable and accrued revenues	**$ (146)**	$ 825	$ (697)
Inventories	**(34)**	(22)	68
Accounts payable and accrued liabilities	**654**	585	(169)
Income taxes payable	**23**	177	54
	$ 497	$ 1,565	$ (744)
Investing Activities			
Accounts payable and accrued liabilities	**$ 330**	$ (29)	$ (112)

C) Supplementary Cash Flow Information – Continuing Operations

For the years ended December 31	2005	2004	2003
Interest Paid	**$ 522**	$ 402	$ 285
Income Taxes Paid (Received)	**$ 1,096**	$ 136	$ (127)

18. Commitments and Contingencies

Commitments

As at December 31, 2005	2006	2007	2008	2009	2010	Thereafter	**Total**
Pipeline Transportation	$ 339	$ 305	$ 255	$ 208	$ 196	$ 850	**$2,153**
Purchases of Goods and Services	230	220	137	97	41	33	**758**
Product Purchases	33	23	22	22	22	98	**220**
Operating Leases	48	46	40	33	32	132	**331**
Capital Commitments	92	24	5	—	—	38	**159**
Total	$ 742	$ 618	$ 459	$ 360	$ 291	$1,151	**$3,621**
Product Sales	$ 61	$ 64	$ 68	$ 40	$ 42	$ 300	**$ 575**
Discontinued Operations	$ (331)	$ 27	$ 40	$ 59	$ 102	$ 793	**$ 690**

In addition to the above, the Company has made commitments related to its risk management program (see Note 16).

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

California

As disclosed previously, 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 whereby 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.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits 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.

In all but one of the class actions in the United States District Court and in the Gallo action, decisions dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims are on appeal to the United States Court of Appeals for the Ninth Circuit.

Without admitting any liability in the lawsuits, in November 2005, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court, subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD is also a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle the New York class action lawsuit, subject to final documentation and approval by the New York District Court.

Based on the aforementioned settlements, during the fourth quarter of 2005 a total of $30 million was recorded, which amount has been included in Administrative costs in the Net Earnings from Discontinued Operations. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding 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.

Asset Retirement

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 $816 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

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.

19. 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 GAAP 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	2005	2004	2003
Net Earnings – Canadian GAAP		**$ 3,426**	$ 3,513	$ 2,360
Less:				
Net Earnings From Discontinued Operations – Canadian GAAP		**597**	1,420	222
Net Earnings From Continuing Operations – Canadian GAAP		**2,829**	2,093	2,138
Increase (Decrease) Under U.S. GAAP:				
Revenues, net of royalties	B	**(217)**	345	(101)
Operating	B	**1**	(3)	—
Depreciation, depletion and amortization	A	**55**	31	14
Interest, net	B	**(16)**	(41)	70
Stock-based compensation – options	C	**(12)**	(5)	(1)
Income tax expense	E	**59**	(105)	7
Net Earnings From Continuing Operations – U.S. GAAP		**2,699**	2,315	2,127
Net Earnings From Discontinued Operations – U.S. GAAP		**553**	1,418	156
Net Earnings Before Change in Accounting Policy – U.S. GAAP		**3,252**	3,733	2,283
Cumulative Effect of Change in Accounting Policy, net of tax	G	**—**	—	66
Net Earnings – U.S. GAAP		**$ 3,252**	$ 3,733	$ 2,349
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.41
Diluted		**$ 3.66**	$ 3.99	$ 2.38
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.48
Diluted		**$ 3.66**	$ 3.99	$ 2.45

Consolidated Statement of Earnings – U.S. GAAP

For the years ended December 31	Note	2005	2004	2003
Revenues, Net of Royalties	B	$ 14,049	$ 10,604	$ 8,420
Expenses				
Production and mineral taxes		453	311	164
Transportation and selling		538	490	476
Operating	B	1,437	1,102	965
Purchased product		4,159	3,092	2,572
Depreciation, depletion and amortization	A, G	2,714	2,348	1,953
Administrative		268	197	173
Interest, net	B	540	439	214
Accretion of asset retirement obligation	G	37	22	17
Foreign exchange (gain) loss, net		(24)	(412)	(603)
Stock-based compensation – options	C	27	22	19
Gain on divestitures		—	(59)	(1)
Net Earnings Before Income Tax		3,900	3,052	2,471
Income tax expense	E	1,201	737	344
Net Earnings From Continuing Operations – U.S. GAAP		2,699	2,315	2,127
Net Earnings From Discontinued Operations – U.S. GAAP	A, B	553	1,418	156
Net Earnings Before Change in Accounting Policy – U.S. GAAP		3,252	3,733	2,283
Cumulative Effect of Change in Accounting Policy, net of tax	G	—	—	66
Net Earnings – U.S. GAAP		$ 3,252	$ 3,733	$ 2,349
Net Earnings From Continuing Operations per Common Share – U.S. GAAP				
Basic		$ 3.11	$ 2.51	$ 2.24
Diluted		$ 3.04	$ 2.47	$ 2.22
Net Earnings From Discontinued Operations per Common Share – U.S. GAAP				
Basic		$ 0.64	$ 1.54	$ 0.17
Diluted		$ 0.62	$ 1.52	$ 0.16
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		$ 3.75	$ 4.05	$ 2.41
Diluted		$ 3.66	$ 3.99	$ 2.38
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		$ 3.75	$ 4.05	$ 2.48
Diluted		$ 3.66	$ 3.99	$ 2.45

Consolidated Statement of Comprehensive Income

For the years ended December 31	Note	2005	2004	2003
Net Earnings – U.S. GAAP		$ 3,252	$ 3,733	$ 2,349
Change in Fair Value of Financial Instruments	B, F	—	—	4
Foreign Currency Translation Adjustment	D	573	420	1,046
Change in Accounting Policy		—	—	6
Comprehensive Income		$ 3,825	$ 4,153	$ 3,405

Consolidated Statement of Accumulated Other Comprehensive Income

For the years ended December 31	Note	2005	2004	2003
Balance, Beginning of Year		$ 1,025	$ 605	$ (451)
Change in Fair Value of Financial Instruments	B, F	—	—	4
Foreign Currency Translation Adjustment	D	573	420	1,046
Change in Accounting Policy		—	—	6
Balance, End of Year		$ 1,598	$ 1,025	$ 605

Consolidated Statement of Retained Earnings

For the years ended December 31	2005	2004	2003
Retained Earnings, Beginning of Year	**$ 7,955**	$ 5,076	$ 3,325
Net Earnings	**3,252**	3,733	2,349
Dividends on Common Shares	**(238)**	(183)	(139)
Charges for Normal Course Issuer Bid	**(1,642)**	(671)	(468)
Change in Accounting Policy	**—**	—	9
Retained Earnings, End of Year	**$ 9,327**	$ 7,955	$ 5,076

Condensed Consolidated Balance Sheet

		2005		2004	
As at December 31	Note	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets					
Current Assets	A, B	**$ 3,604**	**$ 3,603**	$ 3,505	$ 3,497
Property, Plant and Equipment	A, G				
(includes unproved properties of $2,470 and $2,740 as of December 31, 2005 and 2004, respectively)		**39,339**	**39,224**	33,838	33,725
Accumulated Depreciation, Depletion and Amortization		**(14,458)**	**(14,383)**	(11,335)	(11,318)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**24,881**	**24,841**	22,503	22,407
Investments and Other Assets	B	**496**	**491**	334	330
Risk Management	B	**530**	**530**	87	87
Assets of Discontinued Operations		**2,113**	**2,113**	2,325	2,310
Goodwill		**2,524**	**2,524**	2,459	2,459
		$ 34,148	**$ 34,102**	$ 31,213	$ 31,090
Liabilities and Shareholders' Equity					
Current Liabilities	A, B	**$ 4,871**	**$ 4,821**	$ 2,947	$ 2,950
Long-term Debt		**6,703**	**6,703**	7,742	7,742
Other Liabilities	B	**93**	**22**	118	64
Risk Management	B	**102**	**102**	192	178
Asset Retirement Obligation	G	**816**	**816**	611	611
Liabilities of Discontinued Operations	A, B	**267**	**267**	213	172
Future Income Taxes	E, G	**5,289**	**5,153**	5,082	5,038
		18,141	**17,884**	16,905	16,755
Share Capital	C				
Common Shares, no par value		**5,131**	**5,160**	5,299	5,317
Outstanding: 2005 – 854.9 million shares					
2004 – 900.6 million shares					
Share Options, net		**—**	**—**	10	10
Paid in Surplus		**133**	**133**	28	28
Retained Earnings		**9,481**	**9,327**	7,935	7,955
Foreign Currency Translation Adjustment	D	**1,262**	**—**	1,036	—
Accumulated Other Comprehensive Income		**—**	**1,598**	—	1,025
		16,007	**16,218**	14,308	14,335
		$ 34,148	**$ 34,102**	$ 31,213	$ 31,090

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

As at December 31		2005		2004	
	Note	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets of Discontinued Operations	A, B	$ 3,163	$ 3,163	$ 3,296	$ 3,284
Liabilities of Discontinued Operations	A, B	705	680	649	723

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

For the years ended December 31	2005	2004	2003
Operating Activities			
Net earnings from continuing operations	$ 2,699	$ 2,315	$ 2,127
Depreciation, depletion and amortization	2,714	2,348	1,953
Future income taxes	(4)	178	463
Unrealized loss (gain) on risk management	668	(116)	31
Unrealized foreign exchange gain	(50)	(285)	(545)
Accretion of asset retirement obligation	37	22	17
Gain on divestitures	–	(59)	(1)
Other	174	99	57
Cash flow from discontinued operations	464	478	357
Net change in other assets and liabilities	(281)	(176)	(84)
Net change in non-cash working capital from continuing operations	497	1,565	(744)
Net change in non-cash working capital from discontinued operations	(187)	(1,778)	673
Cash From Operating Activities	$ 6,731	$ 4,591	$ 4,304
Cash Used in Investing Activities	$ (3,942)	$ (4,259)	$ (3,729)
Cash From (Used in) Financing Activities	$ (3,275)	$ 163	$ (542)

Notes:

A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP and U.S. GAAP differ in the following respects. 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 percent, 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 forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable 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.

Effective January 1, 2004, the Canadian Accounting Standard's Board amended the Full Cost Accounting Guideline. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using estimated future prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices.

B) Derivative Instruments and Hedging

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 "Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments" which requires derivatives not designated as hedges to be recorded in 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. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2005, under Canadian GAAP a $40 million deferred gain remains.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded in 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 SFAS 133.

Unrealized gain/(loss) on derivatives related to:

For the years ended December 31	2005	2004	2003
Commodity Prices (Revenues, net of royalties)	**$ (703)**	$ 76	$ (205)
Interest and Currency Swaps (Interest, net)	**(9)**	(29)	70
Total Unrealized (Loss) Gain	**$ (712)**	$ 47	$ (135)
Amounts Allocated to Continuing Operations	**$ (668)**	$ 116	$ (31)
Amounts Allocated to Discontinued Operations	**(44)**	(69)	(104)
	$ (712)	$ 47	$ (135)

As at December 31, 2005, it is estimated that over the following 12 months, $0.08 million ($0.05 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 financial statements, which would be the same adjustment under U.S. GAAP, see Note 15.

Under Financial Accounting Standards Board ("FASB") Interpretation ("FIN") 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 of Canadian Pacific Ltd.("CPL"), an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana 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	2005	2004	2003
Net Earnings Before Income Tax – U.S. GAAP	**$ 3,900**	$ 3,052	$ 2,471
Canadian Statutory Rate	**37.9%**	39.1%	41.0%
Expected Income Tax	**1,478**	1,193	1,013
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	**207**	192	231
Canadian resource allowance	**(202)**	(246)	(258)
Canadian resource allowance on unrealized risk management losses	**—**	(10)	—
Statutory and other rate differences	**(235)**	(50)	(44)
Effect of tax rate reductions	**—**	(109)	(359)
Non-taxable capital gains	**(24)**	(91)	(119)
Previously unrecognized capital losses	**—**	17	(119)
Tax basis retained on divestitures	**(68)**	(169)	—
Large corporations tax	**25**	24	27
Other	**20**	(14)	(28)
Income Tax – U.S. GAAP	**$ 1,201**	$ 737	$ 344
Effective Tax Rate	**30.7%**	24.1%	13.9%

The net future income tax liability is comprised of:

As at December 31	2005	2004
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,407**	$ 4,354
Timing of partnership items	**1,226**	975
Future Tax Assets		
Net operating losses carried forward	**(47)**	(103)
Other	**(433)**	(188)
Net Future Income Tax Liability	**$ 5,153**	$ 5,038

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 SFAS 133. At December 31, 2005, accumulated other comprehensive income related to these items was a loss of $4.8 million, net of tax.

G) Asset Retirement Obligation

In 2003, 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. SFAS 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.

H) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented. Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31	**2005**	2004	2003
Dividends per share	**$ 0.28**	$ 0.20	$ 0.15

J) Recent Accounting Pronouncements

In the year ended December 31, 2005, the Company adopted, for U.S. GAAP purposes, FIN 47, "Accounting for Conditional Asset Retirement Obligations" in order to address the diverse accounting practices which have developed with regard to the timing of recognition for asset retirement obligations. This interpretation did not have a material impact on its financial statements.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- Beginning with the year ended December 31, 2006, the Company will be required to adopt, for U.S. GAAP purposes, revised SFAS 123 "Share-Based Payment". This amended statement eliminates the alternative to use Accounting Principles Board ("APB") Opinion No. 25's intrinsic value method of accounting, as was provided in the originally issued Statement 123. As a result, public entities are required to use the grant-date fair value of the award in measuring the cost of employee services received in exchange for an equity award of equity instruments. Compensation cost is required to be recognized over the requisite service period. For liability awards, entities are required to re-measure the fair value of the award at each reporting date up until the settlement date. Changes in fair value of liability awards during the requisite service period are required to be recognized as compensation cost over the vesting period. Compensation cost is not recognized for equity instruments for which employees do not render the requisite service. Although the Company is in the process of assessing the impact of this amendment, the Company does not expect the amendments to have a material impact on its consolidated statements.

- As of January 1, 2006, the Company will be required to adopt, for U.S. GAAP purposes, SFAS 154 "Accounting Changes and Error Corrections, a replacement of APB Opinion No.20 and SFAS 3". SFAS 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The Company does not expect this standard to have a material impact on its financial statements.

Supplementary Oil and Gas Information — SFAS 69 (unaudited)

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including Statement of Financial Accounting Standard Number 69 ("SFAS 69").

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 reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of price 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 interest (disposed of in 2003) and Midstream interests.

Net Proved Reserves (unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

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**
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**
2004											
Beginning of year	5,256	3,129	26	—	**8,411**	629.4	41.6	161.7	124.5	—	**957.2**
Revisions and improved recovery	67	(252)	—	—	**(185)**	31.1	0.2	(11.5)	—	—	**19.8**
Extensions and discoveries	1,422	1,009	—	—	**2,431**	93.6	47.6	21.2	—	—	**162.4**
Purchase of reserves in place	65	1,150	10	—	**1,225**	29.4	11.7	—	10.1	—	**51.2**
Sale of reserves in place	(215)	(82)	(25)	—	**(322)**	(97.3)	(5.4)	—	(128.4)	—	**(231.1)**
Production	(771)	(318)	(11)	—	**(1,100)**	(56.6)	(4.7)	(28.1)	(6.2)	—	**(95.6)**
End of year before bitumen revisions	5,824	4,636	—	—	**10,460**	629.6	91.0	143.3	—	—	**863.9**
Revisions due to bitumen price	—	—	—	—	**—**	(362.7)[3]	—	—	—	—	**(362.7)**
End of year	5,824	4,636	—	—	**10,460**	266.9	91.0	143.3	—	—	**501.2**
Developed	4,406	2,496	—	—	**6,902**	210.2	31.5	122.5	—	—	**364.2**
Undeveloped	1,418	2,140	—	—	**3,558**	56.7	59.5	20.8	—	—	**137.0**
Total	5,824	4,636	—	—	**10,460**	266.9	91.0	143.3	—	—	**501.2**
2005											
Beginning of year	5,824	4,636	—	—	**10,460**	266.9	91.0	143.3	—	—	**501.2**
Revisions and improved recovery	202	(260)	—	—	**(58)**	222.1	(3.2)	8.1	—	—	**227.0**
Extensions and discoveries	1,289	1,252	—	—	**2,541**	148.1	8.9	10.2	—	—	**167.2**
Purchase of reserves in place	7	76	—	—	**83**	—	0.4	—	—	—	**0.4**
Sale of reserves in place	(30)	(37)	—	—	**(67)**	(15.1)	(39.0)	—	—	—	**(54.1)**
Production	(775)	(400)	—	—	**(1,175)**	(52.2)	(5.0)	(26.6)	—	—	**(83.8)**
End of year before reinstatement of bitumen	6,517	5,267	—	—	**11,784**	569.8	53.1	135.0	—	—	**757.9**
Reinstatement of bitumen	—	—	—	—	**—**	362.7[4]	—	—	—	—	**362.7**
End of year	6,517	5,267	—	—	**11,784**	932.5[5]	53.1	135.0[6]	—	—	**1,120.6**
Developed	4,513	2,718	—	—	**7,231**	318.7	32.2	104.0	—	—	**454.9**
Undeveloped	2,004	2,549	—	—	**4,553**	613.8	20.9	31.0	—	—	**665.7**
Total	6,517	5,267	—	—	**11,784**	932.5	53.1	135.0	—	—	**1,120.6**

(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.

(3) Removal of the Corporation's Foster Creek proved bitumen reserves as a result of low bitumen prices on December 31, 2004. This included approximately 5.4 million barrels that were included under revisions and improved recovery and approximately 70.4 million barrels that were included under extensions and discoveries in 2004.

(4) Reinstatement, as a result of year-end 2005 prices, of the Corporation's Foster Creek proved bitumen reserves that were deducted as a revision due to bitumen price at year-end 2004.

(5) Proved crude oil and NGLs reserves at December 31, 2005 include 657.4 million barrels of bitumen, the vast majority of which are located at Foster Creek. Changes to bitumen reserves during 2005 included revisions of 174.6 million barrels and extensions and discoveries of 134.0 million barrels.

(6) The Corporation expects to complete the disposition of its Ecuadorian operations in 2006. Accordingly, Ecuador is reported as discontinued operations for financial reporting purposes.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

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

($ millions)	Canada			United States			Ecuador		
	2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Future cash inflows	**71,786**	37,791	35,126	**40,504**	27,063	17,472	**5,350**	3,317	3,533
Less future:									
Production costs	**16,765**	7,760	9,630	**3,262**	2,462	1,456	**2,093**	1,136	738
Development costs	**6,164**	3,157	3,024	**4,174**	3,213	1,336	**429**	198	211
Asset retirement obligation payments	**2,269**	1,749	1,364	**264**	193	97	**24**	22	38
Income taxes	**13,170**	6,279	5,874	**11,041**	7,021	4,960	**662**	342	536
Future net cash flows	**33,418**	18,846	15,234	**21,763**	14,174	9,623	**2,142**	1,619	2,010
Less 10% annual discount for estimated timing of cash flows	**13,281**	6,668	5,219	**10,291**	6,686	4,735	**574**	417	643
Discounted future net cash flows	**20,137**	12,178	10,015	**11,472**	7,488	4,888	**1,568**	1,202	1,367

($ millions)	United Kingdom			Total		
	2005	2004	2003	**2005**	2004	2003
Future cash inflows	**–**	–	3,483	**117,640**	68,171	59,614
Less future:						
Production costs	**–**	–	961	**22,120**	11,358	12,785
Development costs	**–**	–	941	**10,767**	6,568	5,512
Asset retirement obligation payments	**–**	–	67	**2,557**	1,964	1,566
Income taxes	**–**	–	456	**24,873**	13,642	11,826
Future net cash flows	**–**	–	1,058	**57,323**	34,639	27,925
Less 10% annual discount for estimated timing of cash flows	**–**	–	493	**24,146**	13,771	11,090
Discounted future net cash flows	**–**	–	565	**33,177**	20,868	16,835

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

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

	Canada			United States			Ecuador		
($ millions)	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Balance, beginning of year	**12,178**	10,015	8,833	**7,488**	4,888	2,151	**1,202**	1,367	1,258
Changes resulting from:									
Sales of oil and gas produced during the period	**(5,720)**	(3,965)	(3,429)	**(2,436)**	(1,474)	(889)	**(604)**	(264)	(258)
Discoveries and extensions, net of related costs	**4,278**	3,562	1,272	**3,582**	2,436	1,381	**159**	236	126
Purchases of proved reserves in place	**26**	531	26	**237**	2,786	340	**–**	—	93
Sales of proved reserves in place	**(279)**	(1,579)	(95)	**(486)**	(271)	(108)	**–**	—	(54)
Net change in prices and production costs	**11,624**	2,264	242	**4,716**	143	2,751	**967**	(294)	(47)
Revisions to quantity estimates	**1,071**	546	416	**(700)**	(542)	4	**88**	(125)	4
Accretion of discount	**1,629**	1,349	1,636	**1,103**	725	304	**147**	176	182
Previously estimated development costs incurred net of change in future development costs	**(888)**	57	340	**162**	22	534	**(148)**	15	89
Other	**63**	32	470	**(64)**	(49)	157	**8**	(29)	(27)
Net change in income taxes	**(3,845)**	(634)	304	**(2,130)**	(1,176)	(1,737)	**(251)**	120	1
Balance, end of year	**20,137**	12,178	10,015	**11,472**	7,488	4,888	**1,568**	1,202	1,367

	United Kingdom			Total		
($ millions)	**2005**	2004	2003	**2005**	2004	2003
Balance, beginning of year	**–**	565	411	**20,868**	16,835	12,653
Changes resulting from:						
Sales of oil and gas produced during the period	**–**	(78)	(83)	**(8,760)**	(5,781)	(4,659)
Discoveries and extensions, net of related costs	**–**	—	—	**8,019**	6,234	2,779
Purchases of proved reserves in place	**–**	77	57	**263**	3,394	516
Sales of proved reserves in place	**–**	(899)	—	**(765)**	(2,749)	(257)
Net change in prices and production costs	**–**	—	(119)	**17,307**	2,113	2,827
Revisions to quantity estimates	**–**	—	157	**459**	(121)	581
Accretion of discount	**–**	82	91	**2,879**	2,332	2,213
Previously estimated development costs incurred net of change in future development costs	**–**	—	108	**(874)**	94	1,071
Other	**–**	—	(38)	**7**	(46)	562
Net change in income taxes	**–**	253	(19)	**(6,226)**	(1,437)	(1,451)
Balance, end of year	**–**	—	565	**33,177**	20,868	16,835

Results of Operations and Capitalized Costs (unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

Results of Operations

($ millions)	Canada 2005	Canada 2004	Canada 2003	United States 2005	United States 2004	United States 2003	Ecuador (1) 2005	Ecuador (1) 2004	Ecuador (1) 2003
Oil and gas revenues, net of royalties, transportation and selling costs	**6,701**	4,787	4,189	**3,052**	1,861	1,091	**873**	451	367
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**981**	822	760	**616**	387	202	**269**	187	109
Depreciation, depletion and amortization	**1,961**	1,752	1,511	**712**	487	297	**234**	263	159
Operating income (loss)	**3,759**	2,213	1,918	**1,724**	987	592	**370**	1	99
Income taxes	**1,274**	841	218	**638**	375	219	**134**	5	17
Results of operations	**2,485**	1,372	1,700	**1,086**	612	373	**236**	(4)	82

($ millions)	United Kingdom 2005	United Kingdom 2004	United Kingdom 2003	Other 2005	Other 2004	Other 2003	Total 2005	Total 2004	Total 2003
Oil and gas revenues, net of royalties, transportation and selling costs	**–**	117	102	**–**	–	–	**10,626**	7,216	5,749
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**–**	39	19	**6**	4	20	**1,872**	1,439	1,110
Depreciation, depletion and amortization	**–**	118	74	**8**	25	83	**2,915**	2,645	2,124
Operating income (loss)	**–**	(40)	9	**(14)**	(29)	(103)	**5,839**	3,132	2,515
Income taxes	**–**	(15)	17	**–**	–	(4)	**2,046**	1,206	467
Results of operations	**–**	(25)	(8)	**(14)**	(29)	(99)	**3,793**	1,926	2,048

(1) Ecuador is treated as discontinued operations for financial reporting purposes. The results of operations for 2005 includes a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments.

Capitalized Costs

($ millions)	Canada 2005	Canada 2004	Canada 2003	United States 2005	United States 2004	United States 2003	Ecuador 2005	Ecuador 2004	Ecuador 2003
Proved oil and gas properties	**27,074**	22,455	18,549	**7,753**	7,552	3,485	**1,926**	1,784	1,372
Unproved oil and gas properties	**1,998**	1,855	1,981	**870**	728	501	**18**	45	70
Total capital cost	**29,072**	24,310	20,530	**8,623**	8,280	3,986	**1,944**	1,829	1,442
Accumulated DD&A	**12,131**	9,770	7,498	**1,750**	1,046	516	**778**	534	188
Net capitalized costs	**16,941**	14,540	13,032	**6,873**	7,234	3,470	**1,166**	1,295	1,254

($ millions)	United Kingdom 2005	United Kingdom 2004	United Kingdom 2003	Other 2005	Other 2004	Other 2003	Total 2005	Total 2004	Total 2003
Proved oil and gas properties	**–**	–	675	**–**	–	–	**36,753**	31,791	24,081
Unproved oil and gas properties	**–**	–	77	**470**	425	317	**3,356**	3,053	2,946
Total capital cost	**–**	–	752	**470**	425	317	**40,109**	34,844	27,027
Accumulated DD&A	**–**	–	230	**222**	247	206	**14,881**	11,597	8,638
Net capitalized costs	**–**	–	522	**248**	178	111	**25,228**	23,247	18,389

Costs and Costs Incurred (unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

Costs Incurred	Canada			United States			Ecuador		
($ millions)	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Acquisitions									
Unproved reserves	**–**	42	47	**271**	954	21	**–**	–	80
Proved reserves	**30**	204	207	**141**	2,051	115	**–**	–	59
Total acquisitions	**30**	246	254	**412**	3,005	136	**–**	–	139
Exploration costs	**817**	555	846	**264**	164	187	**15**	28	20
Development costs	**3,333**	2,669	2,131	**1,724**	1,103	651	**164**	213	111
Total costs incurred	**4,180**	3,470	3,231	**2,400**	4,272	974	**179**	241	270

	United Kingdom			Other			Total		
($ millions)	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Acquisitions									
Unproved reserves	**–**	–	16	**–**	–	–	**271**	996	164
Proved reserves	**–**	130	95	**–**	–	–	**171**	2,385	476
Total acquisitions	**–**	130	111	**–**	–	–	**442**	3,381	640
Exploration costs	**–**	22	30	**70**	79	78	**1,166**	848	1,161
Development costs	**–**	364	96	**–**	–	–	**5,221**	4,349	2,989
Total costs incurred	**–**	516	237	**70**	79	78	**6,829**	8,578	4,790

Supplemental Financial Information – Financial Statistics (unaudited)

Financial Statistics

($ millions, except per share amounts)	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Year	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Total Consolidated										
Cash Flow	**7,426**	2,510	1,931	1,572	1,413	4,980	1,491	1,363	1,131	995
Per share – Basic	**8.55**	2.94	2.26	1.80	1.58	5.41	1.62	1.48	1.23	1.08
– Diluted	**8.35**	2.88	2.20	1.76	1.55	5.32	1.60	1.46	1.21	1.07
Net Earnings (Loss)	**3,426**	2,366	266	839	(45)	3,513	2,580	393	250	290
Per share – Basic	**3.95**	2.77	0.31	0.96	(0.05)	3.82	2.81	0.43	0.27	0.31
– Diluted	**3.85**	2.71	0.30	0.94	(0.05)	3.75	2.77	0.42	0.27	0.31
Operating Earnings (1)	**3,241**	1,271	704	655	611	1,976	573	559	379	465
Per share – Diluted	**3.64**	1.46	0.80	0.73	0.67	2.11	0.62	0.60	0.41	0.50
Continuing Operations										
Cash Flow from Continuing Operations	**6,962**	2,390	1,823	1,502	1,247	4,502	1,358	1,256	1,029	859
Net Earnings (Loss) from										
Continuing Operations	**2,829**	1,869	348	774	(162)	2,093	1,055	463	270	305
Per share – Basic	**3.26**	2.19	0.41	0.89	(0.18)	2.27	1.15	0.50	0.29	0.33
– Diluted	**3.18**	2.14	0.40	0.87	(0.18)	2.24	1.13	0.50	0.29	0.33
Operating Earnings – Continuing Operations (2)	**3,048**	1,229	733	611	475	1,872	513	555	368	436
Effective Tax Rates using										
Net Earnings	**30.8%**					23.2%				
Operating Earnings, excluding dispositions	**33.0%**					35.3%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.825**	0.852	0.833	0.804	0.815	0.768	0.820	0.765	0.736	0.759
Period end	**0.858**	0.858	0.861	0.816	0.827	0.831	0.831	0.791	0.746	0.763

(1) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

(2) Operating Earnings - Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

Common Share Information

(restated for the effect of the share split)

	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Year	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Common Shares Outstanding (millions)										
Period end	**854.9**	854.9	853.8	860.2	881.7	900.6	900.6	924.0	922.0	919.6
Average – Basic	**868.3**	854.4	855.1	872.0	891.8	920.8	917.6	923.4	920.6	921.8
Average – Diluted	**889.2**	872.5	875.8	891.9	909.0	936.0	929.8	932.4	931.0	934.2
Price Range ($ per share)										
TSX – C$										
High	**69.64**	69.64	68.70	51.27	44.28	35.01	35.01	30.30	29.87	29.64
Low	**32.55**	50.04	47.72	39.05	32.55	25.50	28.95	26.15	26.50	25.50
Close	**52.56**	52.56	67.85	48.33	42.72	34.20	34.20	29.18	28.81	28.35
NYSE – US$										
High	**59.82**	59.82	58.49	41.56	36.45	28.72	28.72	23.46	22.37	22.13
Low	**26.45**	42.00	39.26	31.31	26.45	19.03	23.05	19.98	19.03	19.18
Close	**45.16**	45.16	58.31	39.59	35.21	28.53	28.53	23.15	21.58	21.56
Share Volume Traded (millions)	**1,619.6**	552.8	388.9	327.3	350.6	1,056.1	326.7	229.5	242.3	257.6
Share Value Traded										
(US$ millions weekly average)	**1,289.1**	1,433.7	1,400.4	878.8	852.6	456.9	636.0	364.8	392.9	403.7

Financial Metrics

	2005	2004
Net Debt to Capitalization	**33%**	33%
Net Debt to EBITDA	**1.1x**	1.4x
Return on Capital Employed	**17%**	20%
Return on Common Equity	**23%**	27%

Net Capital Investment (unaudited)

Financial Statistics (continued)

Net Capital Investment
($ millions)

	2005	2004
Upstream		
Canada	**$ 4,150**	$ 3,015
United States	**1,982**	1,249
Other Countries	**70**	79
	6,202	4,343
Market Optimization	**197**	10
Corporate	**78**	46
Core Capital from Continuing Operations	**6,477**	4,399
Upstream		
Acquisitions		
Property		
Canada	**30**	64
United States	**418**	300
Corporate		
Petrovera	**—**	253
Tom Brown, Inc. (1)	**—**	2,335
Dispositions		
Property		
Canada	**(447)**	(877)
United States	**(2,074)**	(266)
Corporate		
Petrovera	**—**	(540)
Market Optimization		
Property	**—**	(1)
Corporate		
Kingston	**—**	(25)
Corporate	**(2)**	—
Net Acquisition and Disposition activity from Continuing Operations	**(2,075)**	1,243
Discontinued Operations		
Ecuador	**179**	240
United Kingdom	**—**	(1,656)
Midstream	**(484)**	(20)
Net Capital Investment	**$ 4,097**	$ 4,206

(1) Net cash consideration excluding debt acquired of $406 million.

Operating Statistics – Sales Volumes (unaudited)

Operating Statistics – After Royalties

Sales Volumes	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Year	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Continuing Operations										
Produced Gas (MMcf/d)										
Canada										
Production	**2,125**	2,172	2,123	2,151	2,052	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal/(injection)	**7**	—	—	—	27	(6)	(26)	—	—	—
Canada Sales	**2,132**	2,172	2,123	2,151	2,079	2,099	2,080	2,138	2,177	2,000
United States	**1,095**	1,154	1,099	1,061	1,067	869	1,007	958	824	684
Total Produced Gas	**3,227**	3,326	3,222	3,212	3,146	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids (bbls/d)										
North America										
Light and Medium Oil	**47,328**	45,792	43,313	50,020	50,280	56,215	52,725	52,824	64,448	54,940
Heavy Oil	**83,090**	88,386	81,089	82,274	80,546	84,164	79,336	89,682	79,899	87,729
Natural Gas Liquids (1)										
Canada	**11,907**	12,287	11,924	11,719	11,692	13,452	13,452	12,804	13,588	13,971
United States	**13,675**	12,824	14,131	13,095	14,666	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids	**156,000**	159,289	150,457	157,108	157,184	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations (MMcfe/d)	**4,163**	4,282	4,125	4,155	4,089	3,966	4,044	4,114	4,025	3,679
Discontinued Operations										
Ecuador										
Production (2)	**72,916**	70,480	71,896	73,662	75,695	76,872	76,235	76,567	78,376	76,320
(Under)/over lifting	**(1,851)**	(537)	(3,186)	(486)	(3,208)	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales (bbls/d)	**71,065**	69,943	68,710	73,176	72,487	77,993	77,876	74,846	78,303	80,982
United Kingdom (BOE/d)	**—**	—	—	—	—	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations (MMcfe/d)	**426**	419	412	439	435	594	551	570	630	623
Total (MMcfe/d)	**4,589**	4,701	4,537	4,594	4,524	4,560	4,595	4,684	4,655	4,302

(1) Natural gas liquids include condensate volumes.

(2) 2005 includes approximately 28,700 bbls/day (2004 – 31,000 bbls/day) related to Block 15.

Operating Statistics – After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005					2004				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations										
Produced Gas – Canada ($/Mcf)										
Price	**7.27**	10.00	7.18	6.08	5.70	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	**0.10**	0.10	0.10	0.10	0.09	0.08	0.10	0.09	0.07	0.08
Transportation and selling	**0.36**	0.36	0.36	0.36	0.37	0.39	0.39	0.37	0.35	0.44
Operating	**0.67**	0.72	0.68	0.62	0.65	0.52	0.55	0.50	0.49	0.56
Netback	**6.14**	8.82	6.04	5.00	4.59	4.35	4.82	4.14	4.29	4.13
Produced Gas – United States ($/Mcf)										
Price	**7.82**	10.84	7.51	6.60	6.04	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	**0.81**	1.19	0.75	0.65	0.62	0.65	0.69	0.57	0.80	0.51
Transportation and selling	**0.46**	0.45	0.49	0.42	0.46	0.31	0.27	0.26	0.34	0.39
Operating	**0.53**	0.60	0.55	0.50	0.45	0.37	0.41	0.36	0.37	0.33
Netback	**6.02**	8.60	5.72	5.03	4.51	4.46	5.16	4.17	4.21	4.16
Produced Gas – Total North America ($/Mcf)										
Price	**7.46**	10.29	7.29	6.25	5.81	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	**0.34**	0.48	0.32	0.28	0.27	0.25	0.29	0.24	0.27	0.19
Transportation and selling	**0.40**	0.39	0.41	0.38	0.40	0.36	0.35	0.33	0.35	0.43
Operating	**0.62**	0.68	0.64	0.58	0.58	0.48	0.50	0.46	0.46	0.50
Netback	**6.10**	8.74	5.92	5.01	4.56	4.38	4.94	4.15	4.26	4.14
Natural Gas Liquids – Canada ($/bbl)										
Price	**44.24**	49.51	47.39	39.55	40.04	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes	**—**	—	—	—	—	—	—	—	—	—
Transportation and selling	**0.42**	0.46	0.48	0.39	0.35	0.41	0.47	0.45	0.35	0.35
Netback	**43.82**	49.05	46.91	39.16	39.69	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids – United States ($/bbl)										
Price	**48.36**	54.14	53.92	44.79	40.93	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	**4.86**	5.42	5.46	4.37	4.20	3.82	3.94	4.05	3.93	3.09
Transportation and selling	**0.01**	0.01	0.01	0.01	0.01	—	—	—	—	—
Netback	**43.49**	48.71	48.45	40.41	36.72	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids – Total North America ($/bbl)										
Price	**46.44**	51.87	50.93	42.32	40.53	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	**2.60**	2.77	2.96	2.31	2.34	1.84	2.00	2.14	1.90	1.23
Transportation and selling	**0.20**	0.23	0.23	0.19	0.16	0.21	0.23	0.21	0.18	0.21
Netback	**43.64**	48.87	47.74	39.82	38.03	31.31	35.52	32.50	28.55	28.02
Crude Oil – Light and Medium – North America ($/bbl)										
Price	**45.09**	46.27	55.41	41.44	38.57	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	**1.54**	1.83	1.29	1.71	1.32	0.96	1.38	0.85	0.79	0.86
Transportation and selling	**1.20**	1.14	1.29	1.20	1.19	1.01	1.04	1.08	0.76	1.19
Operating	**6.34**	6.41	6.24	6.34	6.38	5.85	6.41	6.49	4.84	5.87
Netback	**36.01**	36.89	46.59	32.19	29.68	26.85	30.74	28.98	26.04	22.00
Crude Oil – Heavy – North America ($/bbl)										
Price	**27.92**	28.27	39.69	22.77	20.76	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	**0.04**	0.05	0.04	0.02	0.03	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	**1.20**	1.11	1.08	1.13	1.52	1.09	(0.57)	1.63	1.50	1.69
Operating	**6.50**	6.96	6.57	6.57	5.83	5.32	6.27	4.79	4.82	5.44
Netback	**20.18**	20.15	32.00	15.05	13.38	16.96	15.63	21.54	16.04	14.29

Operating Statistics – Netbacks, Royalty Rates (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005					2004				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations (continued)										
Crude Oil – Total North America ($/bbl)										
Price	**34.15**	34.41	45.16	29.83	27.60	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	**0.58**	0.66	0.48	0.66	0.53	0.41	0.57	0.34	0.35	0.37
Transportation and selling	**1.20**	1.12	1.15	1.15	1.39	1.06	0.07	1.42	1.17	1.50
Operating	**6.44**	6.77	6.45	6.48	6.04	5.53	6.33	5.42	4.83	5.61
Netback	**25.93**	25.86	37.08	21.54	19.64	20.92	21.66	24.31	20.50	17.25
Total Liquids – Canada ($/bbl)										
Price	**34.97**	35.65	45.35	30.58	28.60	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	**0.53**	0.60	0.43	0.61	0.48	0.37	0.52	0.31	0.32	0.34
Transportation and selling	**1.14**	1.07	1.09	1.09	1.31	1.00	0.11	1.35	1.10	1.40
Operating	**5.89**	6.19	5.83	5.96	5.55	5.05	5.75	4.98	4.42	5.11
Netback	**27.41**	27.79	38.00	22.92	21.26	21.79	22.98	24.99	21.15	18.10
Total Liquids – Total North America ($/bbl)										
Price	**36.17**	37.16	46.16	31.80	29.77	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	**0.91**	0.99	0.91	0.92	0.83	0.63	0.82	0.63	0.59	0.49
Transportation and selling	**1.04**	0.98	0.99	1.00	1.18	0.93	0.10	1.23	1.02	1.32
Operating	**5.38**	5.70	5.33	5.46	5.03	4.67	5.24	4.55	4.09	4.82
Netback	**28.84**	29.49	38.93	24.42	22.73	22.54	24.04	25.62	21.73	18.76
Total North America ($/Mcfe)										
Price	**7.13**	9.37	7.38	6.03	5.62	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	**0.30**	0.41	0.29	0.25	0.24	0.21	0.25	0.21	0.22	0.16
Transportation and selling	**0.35**	0.34	0.35	0.33	0.36	0.31	0.27	0.30	0.30	0.37
Operating (1)	**0.68**	0.74	0.69	0.66	0.64	0.55	0.59	0.53	0.52	0.58
Netback	**5.80**	7.88	6.05	4.79	4.38	4.23	4.72	4.18	4.11	3.87

(1) Year-to-date operating costs include costs related to long term incentives of $0.03/Mcfe (2004 – $0.01/Mcfe).

Impact of Upstream Realized Financial Hedging

Natural Gas ($/Mcf)	**(0.32)**	(0.88)	(0.39)	(0.14)	0.18	(0.22)	(0.37)	(0.15)	(0.25)	(0.08)
Liquids ($/bbl)	**(5.18)**	(5.00)	(5.70)	(4.88)	(5.18)	(7.08)	(8.24)	(8.75)	(6.53)	(4.79)
Total ($/Mcfe)	**(0.44)**	(0.87)	(0.52)	(0.30)	(0.06)	(0.46)	(0.61)	(0.48)	(0.47)	(0.27)

Average Royalty Rates
(excluding impact of realized financial hedging)

Produced Gas										
Canada	**11.7%**	11.9%	11.8%	11.0%	11.9%	12.5%	12.0%	12.2%	12.7%	13.3%
United States	**18.6%**	18.6%	19.9%	17.9%	18.1%	19.6%	19.8%	18.3%	21.1%	19.3%
Crude Oil										
Canada and United States	**8.8%**	8.8%	8.7%	9.2%	8.7%	9.0%	8.7%	8.8%	11.6%	9.4%
Natural Gas Liquids										
Canada	**14.9%**	14.4%	15.8%	15.6%	13.8%	15.7%	16.5%	18.5%	13.1%	14.8%
United States	**18.2%**	19.4%	20.1%	12.7%	20.0%	18.7%	21.4%	13.6%	20.7%	19.2%
Total North America	**13.3%**	13.5%	13.8%	12.6%	13.3%	13.7%	13.8%	13.2%	14.1%	13.7%

Operating Statistics – Netbacks, Royalty Rates (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005					2004				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Discontinued Operations										
Crude Oil – Ecuador ($/bbl)										
Price	**39.36**	37.82	47.76	36.37	35.80	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	**5.04**	4.63	7.66	4.53	3.42	2.13	2.73	2.62	1.84	1.37
Transportation and selling	**2.25**	1.86	2.45	2.48	2.21	2.12	1.57	2.36	1.92	2.63
Operating	**5.32**	5.82	6.05	5.18	4.26	4.39	5.02	4.35	4.14	4.04
Netback	**26.75**	25.51	31.60	24.18	25.91	20.04	20.65	24.14	19.88	15.78
Crude Oil – United Kingdom ($/bbl)										
Price	**–**	–	–	–	–	36.92	46.19	40.88	34.68	31.11
Transportation and selling	**–**	–	–	–	–	2.06	2.17	2.44	1.85	1.94
Operating	**–**	–	–	–	–	6.75	5.00	9.98	7.84	3.86
Netback	**–**	–	–	–	–	28.11	39.02	28.46	24.99	25.31

Impact of Upstream Realized Financial Hedging – Crude Oil

Ecuador ($/bbl)	**(4.92)**	(3.57)	(7.81)	(4.90)	(3.48)	(9.66)	(14.60)	(10.31)	(7.13)	(6.69)
United Kingdom ($/bbl) (1)	**–**	–	–	–	–	(7.62)	(6.34)	(11.75)	(7.01)	(5.72)

(1) Excludes hedges unwound as a result of the United Kingdom disposition.

Average Royalty Rates
(excluding impact of realized financial hedging)

Crude Oil										
Ecuador	**27.2%**	29.4%	26.3%	26.3%	26.9%	27.1%	27.8%	26.5%	26.5%	27.4%

Drilling Activity

The following tables summarize EnCana's gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations											
2005											
Canada	**605**	**540**	**8**	**8**	**7**	**7**	**620**	**555**	**99**	**719**	**555**
United States	**7**	**6**	**—**	**—**	**9**	**7**	**16**	**13**	**1**	**17**	**13**
Other	**—**	**—**	**3**	**1**	**3**	**2**	**6**	**3**	**—**	**6**	**3**
Total	**612**	**546**	**11**	**9**	**19**	**16**	**642**	**571**	**100**	**742**	**571**
2004											
Canada	566	534	48	47	9	6	623	587	51	674	587
United States	19	16	2	—	—	—	21	16	—	21	16
Other	—	—	3	2	5	2	8	4	—	8	4
Total	585	550	53	49	14	8	652	607	51	703	607
2003											
Canada	532	511	51	31	35	28	618	570	153	771	570
United States	40	35	7	2	4	2	51	39	—	51	39
Other	1	—	—	—	3	1	4	1	—	4	1
Total	573	546	58	33	42	31	673	610	153	826	610
Discontinued Operations											
Ecuador – 2005	**—**	**—**	**2**	**1**	**3**	**2**	**5**	**3**	**—**	**5**	**3**
Ecuador – 2004	—	—	6	3	—	—	6	3	—	6	3
Ecuador – 2003	—	—	3	2	—	—	3	2	—	3	2
United Kingdom – 2004	—	—	1	—	4	2	5	2	—	5	2
United Kingdom – 2003	—	—	2	1	5	3	7	4	—	7	4

Drilling Activity

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations											
2005											
Canada	**3,503**	**3,229**	**277**	**243**	**12**	**11**	**3,792**	**3,483**	**932**	**4,724**	**3,483**
United States	**699**	**604**	**—**	**—**	**—**	**—**	**699**	**604**	**9**	**708**	**604**
Total	**4,202**	**3,833**	**277**	**243**	**12**	**11**	**4,491**	**4,087**	**941**	**5,432**	**4,087**
2004											
Canada	3,632	3,419	386	364	16	15	4,034	3,798	1,105	5,139	3,798
United States	600	515	1	—	3	3	604	518	—	604	518
Total	4,232	3,934	387	364	19	18	4,638	4,316	1,105	5,743	4,316
2003											
Canada	3,964	3,901	756	650	24	18	4,744	4,569	1,347	6,091	4,569
United States	426	401	—	—	1	1	427	402	—	427	402
Total	4,390	4,302	756	650	25	19	5,171	4,971	1,347	6,518	4,971
Discontinued Operations											
Ecuador – 2005	**—**	**—**	**28**	**15**	**3**	**1**	**31**	**16**	**—**	**31**	**16**
Ecuador – 2004	—	—	43	25	1	1	44	26	—	44	26
Ecuador – 2003	—	—	53	39	6	6	59	45	—	59	45
United Kingdom – 2004	—	—	3	1	—	—	3	1	—	3	1
United Kingdom – 2003	—	—	3	—	—	—	3	—	—	3	—

(1) "Gross" wells are the total number of wells in which EnCana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating EnCana's working interest in each of its gross wells.

(3) At December 31, 2005, EnCana was in the process of drilling 50 gross wells (45 net wells) in Canada, 95 gross wells (89 net wells) in the United States, zero wells in Ecuador and one well in another country.

Land

Summary of Working Interest Landholdings

The following tables summarize EnCana's developed, undeveloped and total landholdings at December 31, 2005.

	Developed		Undeveloped		Total	
As at December 31, 2005 (thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Canada						
Alberta						
Fee	4,424	4,424	2,706	2,706	7,130	7,130
Crown	3,842	3,020	5,798	4,818	9,640	7,838
Freehold	223	130	262	220	485	350
	8,489	7,574	8,766	7,744	17,255	15,318
British Columbia						
Crown	875	749	4,495	3,961	5,370	4,710
Freehold	—	—	7	7	7	7
	875	749	4,502	3,968	5,377	4,717
Saskatchewan						
Fee	58	58	457	457	515	515
Crown	158	146	571	557	729	703
Freehold	14	10	62	60	76	70
	230	214	1,090	1,074	1,320	1,288
Manitoba						
Fee	3	3	263	263	266	266
Freehold	—	—	7	7	7	7
	3	3	270	270	273	273
Newfoundland & Labrador						
Crown	—	—	2,549	1,707	2,549	1,707
Nova Scotia						
Crown	—	—	1,353	683	1,353	683
Northwest Territories						
Crown	—	—	178	62	178	62
Nunavut						
Crown	—	—	817	26	817	26
Beaufort						
Crown	—	—	126	4	126	4
Total Canada	9,597	8,540	19,651	15,538	29,248	24,078

Land

Summary of Working Interest Landholdings (continued)

As at December 31, 2005 (thousands of acres)	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States						
Colorado						
Federal/State Lands	188	174	841	774	1,029	948
Freehold	101	95	174	160	275	255
Fee	3	3	47	47	50	50
	292	272	1,062	981	1,354	1,253
Washington						
Federal/State Lands	—	—	668	657	668	657
Freehold	—	—	180	180	180	180
	—	—	848	837	848	837
Texas						
Federal/State Lands	9	3	446	446	455	449
Freehold	330	142	1,090	925	1,420	1,067
Fee	—	—	1	1	1	1
	339	145	1,537	1,372	1,876	1,517
Wyoming						
Federal/State Lands	142	82	696	501	838	583
Freehold	25	18	67	40	92	58
	167	100	763	541	930	641
Other (1)						
Federal/State Lands	12	9	352	211	364	220
Freehold	10	5	77	76	87	81
	22	14	429	287	451	301
Total United States	820	531	4,639	4,018	5,459	4,549
International						
Chad	—	—	54,103	27,052	54,103	27,052
Oman	—	—	9,606	4,803	9,606	4,803
Qatar	—	—	2,161	2,161	2,161	2,161
Greenland	—	—	1,701	1,488	1,701	1,488
Brazil	—	—	1,416	535	1,416	535
Australia	—	—	1,053	357	1,053	357
Azerbaijan	—	—	346	17	346	17
Total International	—	—	70,386	36,413	70,386	36,413
Total	10,417	9,071	94,676	55,969	105,093	65,040
Discontinued Operations						
Ecuador	169	107	1,230	785	1,399	892

(1) Other includes Kansas, Louisiana, Montana, North Dakota, Oklahoma, Utah and Alaska.

(2) This table excludes approximately 4.2 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(3) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The fee lands acreage summary includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

(4) 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.

(5) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.

(6) Gross acres are the total area of properties in which EnCana has an interest.

(7) Net acres are the sum of EnCana's fractional interest in gross acres.

Corporate Information

Corporate Officers

Randall K. Eresman
President & Chief Executive Officer

Roger J. Biemans
Executive Vice-President
President, Canadian Plains Region

Michael M. Graham
Executive Vice-President
President, Canadian Foothills Region

Jeff E. Wojahn
Executive Vice-President
President, USA Region

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

Kerry D. Dyte
General Counsel &
Corporate Secretary

Thomas G. Hinton
Treasurer

William A. Stevenson
Comptroller

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

Gerard J. Protti
Executive Vice-President,
Corporate Relations

Donald T. Swystun
Executive Vice-President,
Corporate Development

Hayward J. Walls
Executive Vice-President,
Corporate Services &
Chief Information Officer

Board of Directors

Michael N. Chernoff (2)(6)
West Vancouver, British Columbia

Ralph S. Cunningham (2)(3)
Houston, Texas

Patrick D. Daniel (1)(5)
Calgary, Alberta

Ian W. Delaney (3)(4)
Toronto, Ontario

Randall K. Eresman
Calgary, Alberta

Michael A. Grandin (3)(4)(6)
Calgary, Alberta

Barry W. Harrison (1)(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 (4)(7)
Calgary, Alberta

Jane L. Peverett (1)
West Vancouver, British Columbia

Dennis A. Sharp (2)(4)
Calgary, Alberta & Montreal, Quebec

James M. Stanford, O.C. (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
www.encana.com

Corporate Information

Transfer Agents & Registrar

Common Shares

CIBC Mellon Trust Company
Calgary, Montreal, Toronto, Halifax, 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
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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
Calgary, Alberta
Toronto, Ontario

The Bank of New York

4.600% Senior Notes
4.750% Senior Notes
6.500% Senior Notes
7.375% Senior Notes
7.650% Senior Notes
8.125% Senior Notes
New York, New York

The Bank of Nova Scotia Trust Company of New York

6.30% Senior Notes
7.20% Senior Notes
New York, New York

Deutsche Bank Trust Company Americas

5.80% Senior Notes
(EnCana Holdings Finance Corp.)
New York, New York

Auditors

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

Independent Qualified Reserve Evaluators

North America

DeGolyer and MacNaughton
Dallas, Texas

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

International

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Stock Exchanges

Common Shares (ECA)

Toronto Stock Exchange
New York Stock Exchange

Principal Operating Subsidiaries & Partnerships

	Percent Owned (1)
EnCana Marketing (USA) Inc.	100
EnCana Oil & Gas (USA) Inc.	100
EnCana Oil & Gas Partnership	100

(1) Includes indirect ownership.

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

Investor Information

Annual Meeting

Shareholders are invited to attend the Annual Meeting being held on Wednesday, April 26, 2006
at 10:30 a.m. local time
at the TELUS Convention Centre
Exhibition Hall E
2nd Floor, North Building
136 – 8th Avenue S.E.
Calgary, Alberta.

Those unable to do so are asked to sign and return the form of proxy that has been 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 2005 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations,
Corporate Finance
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-3550
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General media inquiries should be directed to:

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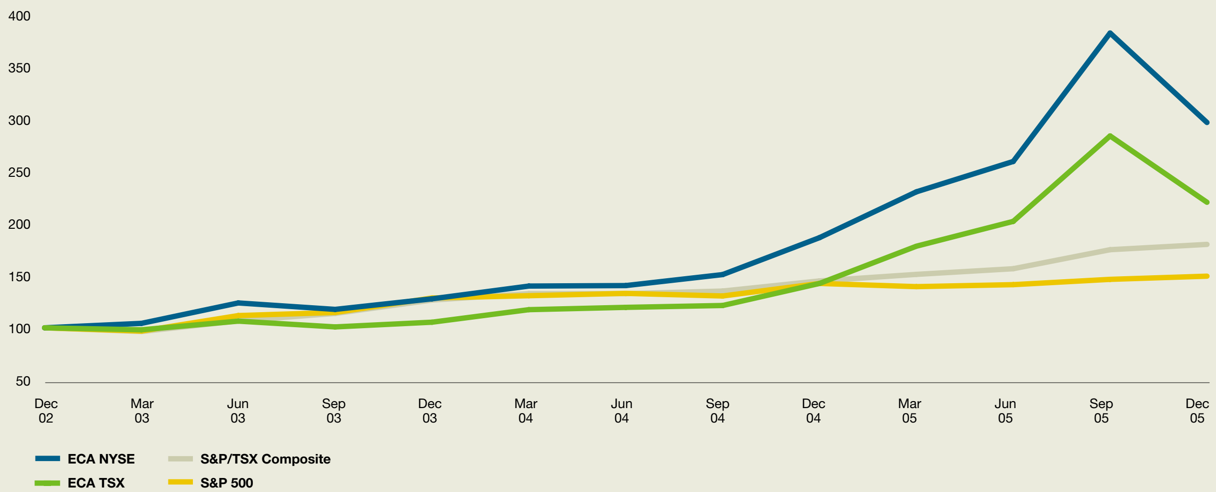
403-645-4748
florence.murphy@encana.com

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
km	kilometre(s)
m	metre(s)
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
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
PCI	product carbon intensity
SAGD	Steam-assisted gravity drainage
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent
WTI	West Texas Intermediate

EnCana Total Return versus Major Indices

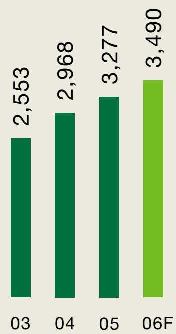


Total Shareholder Return (December 31, 2002 = 100)

2006 Sales Guidance

Total North American Natural Gas Sales

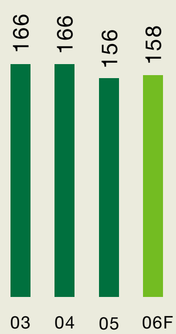
In 2006, North American natural gas sales are forecast to grow by 8%.



06F Midpoint of guidance

Total North American Oil and NGLs Sales

Growing sales from oilsands are expected to offset declining conventional oil production.



06F Midpoint of guidance

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