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ENCANA CORPORATION
2009 ANNUAL REPORT

encana™
natural gas

Headquartered in
Calgary, Alberta, Canada
VOLUME / 1 ISSUE / 1
www.encana.com
/09
TSX: ECA - NYSE: ECA


Power generation for generations.
Natural gas electrical generation produces zero mercury emissions, 99 percent fewer sulphur dioxide (SO_2) emissions and up to 80 percent fewer nitrogen oxides (NO_x) emissions compared to coal. Plus, it also emits up to 65 percent less carbon dioxide (CO_2). That's cleaner, healthier air. **We are Encana.**
encana™
natural gas
Learn more about natural gas and Encana at **www.encana.com**

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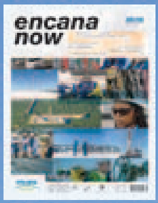


When you think of Encana, we want you to think of natural gas. The articles on the following pages cover a range of topics related to the natural gas industry – from growth opportunities in transportation and other sectors to the reasons we think Encana is an exceptional investment opportunity.

You will learn more about how we conduct our business, and the steps we take to help ensure we're doing so in a manner that respects our stakeholders, employees, communities and the environment.

THIS ISSUE

NATURAL GAS

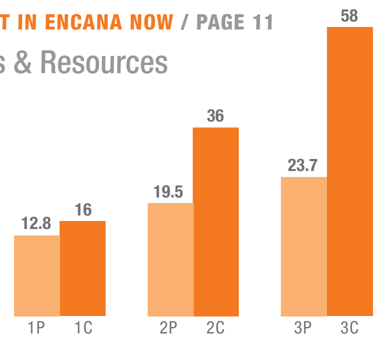
"Encana has set a goal to double in size over the next five years on a per share basis."

RANDY ERESMAN,
PRESIDENT & CEO, ENCANA

Encana has a long and highly successful history of building shareholder value through strong, low-cost production growth, capital discipline, risk management and industry-leading practices in unconventional natural gas development.

Canada's Globe and Mail recently named Encana on its list of Star Stocks of the Decade. Encana delivered a 459 percent gain to investors since inception in 2002.

Reserves & Resources
(Tcfe)



North America's newest and purest natural gas producer

12.7

MILLION NET ACRES AND

ABOUT

35,000

NET DRILLING LOCATIONS

Sustainable Production Growth
(MMcfe/d) (Pro Forma Volumes)

(*Midpoint of guidance)

The natural gas game has changed and Encana is poised to win.

Reserves and resources classifications

Reserves: 1P is proved, 2P is proved plus probable, 3P is proved plus probable and possible;

Economic contingent resources: 1C is low estimate, 2C is best estimate, 3C is high estimate

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NATURAL GAS, continued

ENCANA CONVERTING VEHICLE FLEET / PAGE 26

30 PERCENT

Encana plans to convert approximately 30 percent of its vehicles in the southern Rockies to bi-fuel vehicles by the end of 2011. Encana is also investigating vehicle conversions in other areas of the business.

RISING TO THE CHALLENGE / PAGE 28

PERCENT DECREASE 2008 – 2009

38

of lost time injury frequency (employees and contractors)

15

PERCENT DECREASE

of recordable injury frequency (employees and contractors) 2008 – 2009

ENCANA IN THE COMMUNITY / PAGE 30

one

THOUSAND FIVE HUNDRED

Approximately 1,500 Canadian schoolchildren participated in Encana's Project Webfoot, learning about the importance of wetlands.

FUEL FOR THE 21ST CENTURY / PAGE 24

20 PERCENT

Natural gas provides a 20 percent improvement to the efficiency rate for power generation.

Dow Jones Sustainability Indexes
Member 2009/10

sam
creating sustainable value

GAS FACTORIES / PAGE 19

- Encana's approach to maximize value
- Creating our competitive advantage
- Manufacturing approach to developing key resource plays
- Taking economies of scale to a new level
- Multi-well pad sites reduce costs, improve efficiencies, minimize environmental footprint

PRODUCTION OF THIS REPORT

This publication is printed on FSC-certified paper, made of at least 10 percent post-consumer waste. The cover paper was manufactured using natural gas for eight percent of the manufacturer's total energy needs. Management's Discussion and Analysis and the Financial Statements are printed on a paper manufactured in a plant that uses natural gas to fuel the large dryers needed to dry the coating applied to the paper, and as the primary fuel for its boilers. The inserts are on paper produced by a firm that uses natural gas for 100 percent of its energy. Printing took place at Blanchette Press, which uses natural gas as the source of energy for the furnace that heats its 28,000 square-foot building, housing all its operations – manufacturing and administration.

BECAUSE OF THESE CHOICES, PRODUCTION OF THIS REPORT:

– avoided close to five tons of greenhouse gas emissions
– used almost 50,000 gallons less water
– resulted in close to 3,000 pounds less solid waste

Printed in Canada

NATURAL GAS AND ENCANA OPERATIONS / PAGE 16

20 PERCENT

Approximate cost savings by employees based on annualized targets at the time of the company split.

Encana was one of only five Canadian energy companies named by Corporate Knights to the fifth annual Global 100 list of most sustainable large corporations in the world.

ADVISORY / PAGE 71

Encana reports in U.S. dollars unless otherwise noted, and follows U.S. protocols, which report production, sales and reserves on an after-royalties basis.

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 and company size over the next five years on a per share basis 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. For further details, see the Advisory on page 71 and certain material assumptions on page 145 of this document.

This document contains references to measures commonly referred to as non-GAAP measures, such as cash flow, cash flow from continuing operations, cash flow per share – diluted, free cash flow, operating earnings, operating earnings from continuing operations, operating earnings per share – diluted, adjusted EBITDA, debt, net debt, and capitalization. Additional disclosure relating to these measures is set forth on page 73 in the Advisory. **Except where otherwise indicated, all figures on pages 1 through 36 for prior periods are pro forma, reflecting the corporate split transaction which was completed on November 30, 2009. Additional disclosure relating to the pro forma information is set forth on page 73 in the Advisory.**

Endnotes in articles can be referenced on page 145.

Randy Eresman

PRESIDENT & CHIEF EXECUTIVE OFFICER

We are so confident in our potential, we have set a goal to double the size of Encana over the next five years on a per share basis.

Last year brought tremendous challenges for virtually all businesses and industries as unstable financial markets caused a global economic slowdown. Our industry was impacted by the corresponding reduction in natural gas demand which occurred at the same time that technological breakthroughs enabled large new supplies to come on stream. As a result, prices were pushed to their lowest level in seven years. Despite this extremely challenging business climate, Encana performed very well in 2009.

Our strong commodity price hedges, outstanding operational performance and conservative financial positioning allowed us to surpass all of our financial and operational objectives. Adding to that, we introduced an internal challenge early in 2009 to reduce capital, operating and general administrative costs by 10 percent below our previously approved budget. This challenge was not only met, but overwhelmingly exceeded. After considerable belt tightening, working with suppliers to reduce costs and optimizing all facets of our processes, our staff achieved a 22 percent reduction from planned expenditures. This outstanding achievement allowed us to increase capital spending to preserve and enhance value on some of our largest new natural gas shale plays.

In September of last year, an opportunity presented itself to restart our delayed corporate reorganization. The transaction, designed to split the company into a pure-play natural gas company and an integrated oil company, was successfully completed at the end of November. This resulted in the spin-off of our Integrated Oil and Canadian Plains divisions into Cenovus Energy Inc., an independent, publicly traded energy company.

Encana is now North America's newest pure-play natural gas company. It possesses a sharpened focus on what we do best: the successful exploration and development of unconventional natural gas. We are an exciting new company, poised for industry-leading growth in production, reserves and shareholder returns. Our company has a great balance sheet and we are committed to maintaining an investment grade credit rating. We have a tremendous land position in many of North America's most promising resource plays.

At the end of 2009, we had proved reserves of about 12.8 trillion cubic feet equivalent (Tcfe), probable reserves of 6.7 Tcfe and possible reserves of 4.2 Tcfe, for a total of 23.7 Tcfe. In addition, a recent external evaluation by independent qualified reserves evaluators assigned Encana economic contingent resources in a range that is estimated to be 16 Tcfe at the low end, 36 Tcfe as a best estimate and 58 Tcfe at the high end, as at the end of 2009. On those lands, focused on many of North America's lowest-cost unconventional natural gas basins, we have an enormous drilling inventory estimated at 35,000 net locations. Most importantly, we have the skills and expertise for continued enhancement of capital and operating efficiencies that work toward achieving cost structures that are among the lowest in the industry. We are extremely well-positioned to continue capturing strong financial margins, despite our view that future natural gas prices will be lower than previously forecasted. In fact, we are so confident in our potential, we have set a goal to double the size of Encana over the next five years on a per share basis.

I would like to extend my thanks to our Board of Directors, Executive and staff for reinforcing our strength in a difficult economic environment. Our company's commitment and teamwork ensured a successful split and transition into two companies within an ambitious time frame. As we embark on this new era, we continue to demonstrate the strength and sustainability of our business model – financially, operationally and strategically.

As you read though this report, please bear in mind that 11 of the 12 months in the reporting year include results of the Cenovus assets. Encana's pro forma results (which exclude Cenovus) are discussed below and are the focus of discussion up to page 36 of this report.

MANAGING RISK TO THRIVE DURING FINANCIAL TURMOIL

In a year of global financial upheaval, we achieved remarkable financial performance without the forced sales of assets or staff layoffs experienced by some of our peers. This achievement was testament to our already strong financial position and prudent risk management strategy. While natural gas prices trended downward in 2009, our hedging program provided a buffer from the impacts of low prices for much of the year. Hedging in advance of the weak natural gas prices of 2009 contributed $2.3 billion in after-tax cash flow and allowed us to pursue our capital and operating plans without interruption. We operated throughout 2009 with the view that the very low prices for natural gas were not sustainable, but also that long-term natural gas prices would not likely approach the hefty level previously forecasted. These successfully executed risk management strategies allowed us to continue to advance all of our most prospective plays at a time of correspondingly higher service quality and lower service costs.

While 2009 budgeted programs were fully executed and additional capital was deployed to key areas, we realized about $815 million in net divestitures and reduced operating costs by 18 percent from our budgeted amounts. Operational performance was also very solid, with total production, adjusted for volumes intentionally shut-in or delayed, five percent above budget and six percent above 2008, despite a substantially constrained capital program. We also achieved some of our strongest metrics for capital and operating efficiency, another indication of both the quality of the assets we have accumulated and of our ability to apply leading technologies and efficient operating practices.
Our 2009 operating earnings were $1.8 billion or $2.35 per share, and our cash flow was a robust $5 billion or $6.68 per share.

TECHNOLOGY AND OPERATING EFFICIENCIES DRIVE COSTS DOWN

In 2009, we achieved further improvements in drilling and completion costs in a number of areas as we focused on applying advanced technology to increase operational efficiencies across all of our projects. Our emerging plays continue to deliver performance at the top of our already very strong portfolio. At Encana's Cutbank Ridge resource play in northeast British Columbia, drilling, completion and tie-in costs for each well in the Montney formation were down 11 percent year-over-year despite an increase from eight to nine fractures per well. At our Horn River play in northeast British Columbia, costs were reduced about 25 percent due to improvements in technology, economies of scale and cost deflation. In the Haynesville play in northern Louisiana and East Texas, drilling, completion and tie-in costs were down approximately 40 percent.

As we have worked to reduce operating costs, we have also been optimizing well results across all of our resource plays. In the Horn River, for example, continuous improvements in technology and leveraging economies of scale have produced very strong well results, with many wells showing 30-day initial production rates of eight to 10 million cubic feet per day (MMcf/d). Similarly, at our Haynesville shale play in Louisiana, our latest 10 wells have averaged approximately 20 MMcf/d, flowing at a pressure of about 8,500 pounds per square inch. Additionally, Encana's focused effort to improve well performance has seen two wells flowing at about 19 MMcf/d from the Mid-Bossier zone, also located in Louisiana. We're pleased by these results and look forward to the tremendous development potential of these high growth-oriented assets.

STRATEGY FOR SUCCESS

A disciplined manufacturing approach is integral to our business model. This model has allowed us to consistently improve our operating and financial position, even during a recessionary year, and it further demonstrates our ability to deliver sustainable value creation for shareholders. As we move forward, we will sharpen our competitive focus by continuing to refine our manufacturing approach as a low-cost, margin-maximizing natural gas producer. We believe the future will see even more efficiencies created as we begin building multi-well pads, or what we call gas factories, to optimize the development of our resource plays. These efficiency gains, coupled with the leveraging of third-party capital, will help to accelerate our development rate and ensure future profitability. We will continue to high grade our asset portfolio through the divestiture of non-core, lower-growth, mature properties and the pursuit of acquisitions that complement our core assets with enhanced low-cost growth potential. Risk management and a strong financial position provide a solid foundation for the new Encana, with its sharper focus on natural gas production and advocacy.

ENCANA 2009 HIGHLIGHTS – PRO FORMA

Financial
- Cash flow of $5.0 billion, or $6.68 per share
- Operating earnings of $1.8 billion, or $2.35 per share
- Capital investment, excluding acquisitions and divestitures, of $3.8 billion
- Free cash flow of $1.3 billion

Operating
- Total production of 3.0 billion cubic feet equivalent per day (Bcfe/d)
- Total natural gas production of 2.8 billion cubic feet per day (Bcf/d)
- Oil and natural gas liquids (NGLs) production of 27,000 barrels per day
- Operating and administrative costs of $1.11 per thousand cubic feet equivalent (Mcfe)

Reserves (before price revisions)
- Proved reserves of 12.8 Tcfe
- Added 1.9 Tcfe of proved reserves, compared to production of 1.1 Tcfe, for a production replacement of 169 percent
- Finding and development (F&D) costs were $1.62 per Mcfe
- Three-year (2007 to 2009) F&D costs averaged $1.92 per Mcfe
- Proved reserves life index of approximately 12 years

For additional information on reserves reporting protocols, see page 72.

The North American natural gas game has changed! Encana has the people, the assets and the strategy to win.

OUR CORPORATE RESPONSIBILITIES

It's been a difficult year for our staff and the residents in the Dawson Creek, British Columbia region. We're very concerned about the series of events in this area and remain focused on consulting with impacted stakeholders and enhancing public and worker safety. Our goal is to be a responsible, respected neighbour in the communities where we live and work. We're committed to reinforcing trust and accountability in this region and across all of our operations.

In 2009, as we continued to reinforce our safety culture, our employees achieved the best safety record in our history. Our frequency rates of employee and contractor injuries and lost-time incidents were lower than industry benchmarks. But sadly, despite continuously improving safety policies and practices, two subcontractors' employees lost their lives on Encana work sites and one employee passed away as a result of injuries sustained in a traffic accident en-route to an Encana work site. To their families, friends and co-workers, all of us at Encana extend our deepest condolences and our promise to continually improve our safety performance to help prevent such tragedies from occurring again.

Since its creation in 2002, Encana has earned a reputation as a leading corporate citizen. This position is not just a point of pride; it's one of our greatest assets. It's an asset the new Encana will continue to nurture through actions that demonstrate responsibility, reliability and trust. You can read more about our community involvement in this report.

THE NEW NATURAL GAS ECONOMY

Encana, a leader in the growing North American natural gas industry, has a significant land and resource portfolio on both sides of the border and more than 3 Bcfe per day of production. Unlocking additional potential from North America's unconventional natural gas resources has become economically viable with recent advances in drilling and extraction technology. Our early entry into natural gas shale reservoirs – a leading source of growth in unconventional natural gas – positions us in many of the lowest-cost basins with the largest resource potential.

Our industry is now in the unique position of not only meeting existing demand, but also planning for future growth in demand for this clean, affordable, abundant resource. In 2009, we recognized the potential this premium resource has in meeting the future needs for cleaner North American-sourced fuels and formed a new group within our company called the Natural Gas Economy. This team has taken a leading education and advocacy role in expanding natural gas use in transportation and power generation – two of the most promising growth opportunities. We have a long-term, reliable supply of natural gas in North America, and the increased use of this fuel makes the most economic and environmental sense in meeting many emissions reduction goals. Natural gas is a significantly cleaner fuel than coal, diesel or gasoline when one takes into consideration the production of sulphur dioxide, nitrogen oxides, mercury and other pollutants. Expanding its use in a wide range of applications will significantly reduce emissions. It is the key to our energy future.

Entrenching this natural gas economy will require partnerships with policymakers and the public. In essence, it requires a societal shift that will change our energy habits – brought about through changes in government policy, investment in infrastructure and further advancements in technology. As natural gas use grows, so too will the North American economy. Canada and the U.S. currently import 45 percent of their crude oil and refined products – with imported oil from OPEC nations costing the U.S. about $160 billion and Canada about C$20 billion annually. With an abundant, more environmentally friendly energy resource in North America, expanding the use of natural gas is ultimately expected to reduce our continent's dependence on foreign oil.

BUILDING ON OUR TRACK RECORD

We're expanding demand for natural gas in the Encana tradition of being a first-mover and recognizing opportunities before they are evident to others. We are confident that demand will increase and our business will continue to thrive. Our track record of strong performance, and our continued commitment to shareholders and other stakeholders, will guide us in building the natural gas economy.

In the following pages, you'll read more about the virtues of natural gas and why we see it as the clear, common sense, economic energy solution for future generations. Please take a few minutes to watch the enclosed video and hear how we expect natural gas could shape the 21st century. As we turn our focus to the new Encana, our people, our assets and our strategy will define our direction. I believe our future is very bright.

Randy Eresman

President & Chief Executive Officer
ENCANA CORPORATION
March 16, 2010

The past year was a historic one for Encana. With clear signs of stabilization in global financial markets and our financial situation strong, the management and Board of Directors moved forward to implement a strategic decision we made in 2008, to split the company into two well-structured, highly focused corporate entities.

On November 30, 2009, the split transaction was successfully completed and a new Encana emerged. The company enters the second phase of its history with renewed purpose, while remaining focused on enhancing shareholder value through continued capital discipline, prudent risk management and sound corporate governance.

As Chairman of the Board for Encana, I look ahead with anticipation to the privilege of working with Encana's leaders and staff, guided by Chief Executive Officer Randy Eresman and an exceptional management team.

The split of the company prompted some changes at the Board level as six directors assumed directorships with Cenovus. I extend special acknowledgement and thanks for the contributions of past Encana Board members Ralph Cunningham, Patrick Daniel, Ian Delaney, Michael Grandin, Valerie Nielsen and Wayne Thomson. I wish them success in their future endeavours.

I would also like to welcome Suzanne Nimocks and Fred Fowler, who joined the Encana Board early in 2010. Ms. Nimocks and Mr. Fowler bring a combined wealth of knowledge and experience in several aspects of the energy industry and organizational leadership. Ms. Nimocks contributes a wealth of knowledge through her experience in global management consulting. Mr. Fowler contributes years of expertise in natural gas management.

It was an honour to serve as Encana's Chairman at this critical point in its evolution. I wish to express my appreciation to all Board members for the leadership and dedication they demonstrated during the past year. I also wish to acknowledge Encana's management, employees and contractors. Their efforts were outstanding in a turbulent and uncertain business environment. Encana, with its top-quality talent, exceptional asset base and solid financial performance, is well positioned for future success.

On behalf of the Board of Directors,

David P. O'Brien
Chairman of the Board
ENCANA CORPORATION

David O'Brien

CHAIRMAN OF THE BOARD

CORPORATE OFFICERS

Randy Eresman
President & Chief Executive Officer
Named Encana's Chief Operating Officer in 2002, Randy became President & Chief Executive Officer of Encana on January 1, 2006. He is also a member of Encana's Board of Directors.

Sherri Brillon
Executive Vice-President & Chief Financial Officer
Responsible for treasury, tax, financial risk and risk reporting, internal audit and Sarbanes-Oxley compliance, portfolio management, strategic and corporate planning, and legal and corporate secretarial, Sherri has been named on Canada's Most Powerful Women: Top 100 list three times (2007, 2008 and 2009).

Mike Graham
Executive Vice-President & President, Canadian Division
Responsible for Encana's Canadian Division, including key resource plays Greater Sierra in British Columbia, Cutbank Ridge in British Columbia and Alberta, and Coalbed Methane in Alberta, as well as Encana's Deep Panuke project in Atlantic Canada.

Bob Grant
Executive Vice-President, Corporate Development, EH&S and Reserves
Responsible for ensuring consistency of processes for Encana's acquisitions and divestitures as well as business development, reserves assessment, competitor analysis, corporate environment, health and safety, and corporate responsibility.

Eric Marsh
Executive Vice-President, Natural Gas Economy
Responsible for pursuing the development of expanded natural gas markets in North America, including involvement in government and regulatory relations to expand these markets.

Bill Oliver
Executive Vice-President & Chief Corporate Officer
Responsible for human resources, communications, investor relations, media relations, community investment, information technology and administrative services, including THE BOW building project.

Bill Stevenson
Executive Vice-President & Chief Accounting Officer
Responsible for company-wide corporate comptrollership and accounting functions within Encana, including financial and management reporting, accounting research and accounting systems.

Jeff Wojahn
Executive Vice-President & President, USA Division
Responsible for all of Encana's upstream exploration and production activities in the United States, which includes Encana's key natural gas resource plays at the Jonah field and the Piceance Basin in the U.S. Rockies, and the Fort Worth and East Texas Basins.

Renee Zemljak
Executive Vice-President, Midstream, Marketing & Fundamentals
Responsible for positioning Encana as a natural gas supplier of choice, maximizing the company's netback prices and optimizing the profitability of the company's midstream assets.

Encana has a long and highly successful history of building share value through strong, low-cost production growth, capital discipline, risk management and industry-leading practices in unconventional resource development. Canada's Globe and Mail recently included Encana on its list of Star Stocks of the Decade – delivering to investors a 459 percent gain. Although we can't guarantee we'll repeat that performance, we'll certainly try.

The past year, while challenging, was one where we continued to demonstrate the strength and sustainability of our business model. In my new role as Chief Financial Officer, I will continue to focus on strengthening the foundation that enabled us to deliver outstanding results in market environments unlike any we've seen.

As a pure-play natural gas company, I believe our future is brighter than ever. We have a core focus on being a low-cost leader in natural gas production. When paired with our relentless drive to greater efficiency through the application of technical advances, we are very well positioned to maximize returns from opportunities within our high-quality portfolio of North American natural gas resource plays.

Sherri Brillon, Executive Vice-President & Chief Financial Officer

BOARD OF DIRECTORS

David O'Brien, O.C.
David O'Brien is Chairman of Encana's Board of Directors. He also serves as Chairman of the Board of Royal Bank of Canada and is a director of Molson Coors Brewing Company, TransCanada Corporation and Enerplus Resources Fund, as well as several other private energy-related companies.

Randy Eresman
Randy Eresman is President & Chief Executive Officer of Encana.

Claire Farley
Claire Farley is an Advisory Director of Jefferies, Randall & Dewey (global oil and gas energy industry advisors), and a director of FMC Technologies, Inc.

Fred Fowler
Fred Fowler joined the Encana Board effective February 1, 2010. He is currently Chairman of Spectra Energy Partners, LP. From 2006 to 2008 he was President & Chief Executive Officer of Spectra Energy Corp. Prior to that he occupied various executive positions with Duke Energy Corporation, including President & Chief Operating Officer.

Barry Harrison
Barry Harrison is a director and President of Eastgate Minerals Ltd. He is also Chairman and a director of The Wawanesa Mutual Insurance Company and its related companies, The Wawanesa Life Insurance Company and the U.S. subsidiary, Wawanesa General Insurance Company, headquartered in California.

Suzanne Nimocks
Suzanne Nimocks joined the Encana Board effective January 1, 2010. She was a director and senior partner with McKinsey & Company (global management consulting firm) from 1999 to 2010 and was with the firm in various other capacities since 1989.

Jane Peverett
Jane Peverett is a director of Northwest Natural Gas Company, Canadian Imperial Bank of Commerce and British Columbia Ferry Services Inc., as well as the B.C. Ferry Authority.

Allan Sawin
Allan Sawin is President of Bear Investments Inc. and serves as a director of a number of private companies.

Clayton Woitas
Clayton Woitas is Chairman & Chief Executive Officer of Range Royalty Management Ltd., a director of NuVista Energy Ltd. and Enerplus Resources Fund, and also a director of several private energy-related companies and advisory boards.

Why Invest in Encana Now

The North American natural gas business has experienced significant technological advancements and operating practice innovations over the past decade. Encana has been at the forefront, driving many of those changes – changes targeted at increasing operational efficiencies and lowering overall cost structures, with a constant focus on being the lowest cost producer across its portfolio of plays in the U.S. and Canada. Encana has been a leader in defining the natural gas renaissance that is unfolding and the company is extremely well positioned, both operationally and financially, to continue to be a leader and to achieve sustainable long-term profitable growth.

TREMENDOUS RESOURCE POTENTIAL – SOURCE OF ORGANIC GROWTH

Encana's strategy is built on pursuing unconventional resources. Although the company is North America's newest pure-play natural gas company, for years it has been a leading explorer of emerging resource plays, identifying and acquiring large and attractive land positions before competitors understand their potential.

Today, Encana has one of the largest natural gas resource portfolios in Canada and the U.S. and is uniquely positioned with a land base of more than 12.7 million net acres. Encana's early entry into a number of natural gas plays allowed it to amass large, contiguous land positions in the core areas of several emerging plays, putting the company in an advantageous position for the future. Included within its portfolio, Encana currently holds leading positions in three of the continent's six major gas resource plays.

Independent qualified reserves evaluators have identified estimated proved reserves of 12.8 Tcfe, probable reserves of 6.7 Tcfe and possible reserves of 4.2 Tcfe, for a total of 23.7 Tcfe on Encana's land base. Above and beyond these reserves, the evaluators have also identified economic contingent resources ranging from 16 Tcfe at the low end, 36 Tcfe as a best estimate basis, to 58 Tcfe at the high end as of the end of 2009. This robust resource base, concentrated in many of North America's lowest cost natural gas basins, is the source of an organic drilling inventory totaling about 35,000 net locations. These resources are also the fundamental reason behind Encana's confidence in its ability to achieve predictable, low-cost production growth and its potential to double the company's size over the next five years on a per share basis.

VALUE DRIVEN CULTURE – MAXIMIZING MARGINS

With a large position in many of the key North American natural gas resource plays, Encana has the ability to examine and compare project economics and strategically invest in assets with the potential for long-term development, the highest production growth and the greatest value creation.

Infusing every element of Encana's growth plans is an innovative, value-driven internal culture focused on maximizing margins by increasing operational efficiencies and continually striving to be one of the lowest cost producers in industry. Encana has been an industry leader in the unconventional natural gas business and in creating today's manufacturing approach to development. "The Encana approach involves continuously honing and refining drilling, completion and other technologies and logistics – from one project to the next – replicating successful processes while, at the same time, seeking new ways to innovate and improve," says Mike Graham, Executive Vice-President & President, Canadian Division.

"We delineate the field, investigate the differences between wells and explore various technologies; we use every opportunity to apply the lessons we've learned from our existing operations and the experience gained from the thousands of wells we've drilled in the past," says Graham. Key to the approach, he explains, is repeating successful processes and leveraging what is often a step-change improvement in costs across an inventory of tens of thousands of future wells.

Virtually all of Encana's major resource plays are benefiting from the same technology enhancements that extend the horizontal reach of wells and increase

MIKE GRAHAM, EXECUTIVE VICE-PRESIDENT & PRESIDENT, CANADIAN DIVISION, ENCANA

ECONOMIC CONTINGENT RESOURCES (1)

Economic contingent resources are defined as potentially recoverable discovered resources that are not yet considered mature enough for commercial development due to one or more contingencies, such as proposed timing of development or regulatory approvals. The economic criteria are the same fiscal conditions as for the reserves estimates. All of these reserves and resources estimates are externally evaluated (not just audited or reviewed) by independent qualified reserves evaluators, who recently completed an evaluation of Encana's total reserves and economic contingent resources.

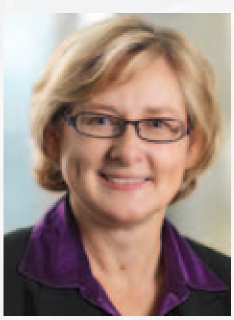
JEFF WOJAHN, EXECUTIVE VICE-PRESIDENT & PRESIDENT, USA DIVISION, ENCANA

the number of fracture stimulations and treatments performed. As this occurs, the company continually improves its operating efficiencies and well performance, driving down costs on a per unit basis, which reduces the overall cost structure and helps maintain strong margins.

When multi-well pad sites and simultaneous operations are employed the potential to capture economies of scale goes to a new level. The drilling of 30 or more wells from a single surface location creates a centralized production facility, draining natural gas from multiple sections of land. The company, along with its service providers, can then better optimize all the logistics associated with the site including the types and sizes of equipment employed. "This gas factory approach is a strategy that we employ across all of our resource plays. Over time it will allow us to maintain our position as one of the lowest cost producers," says Jeff Wojahn, Executive Vice-President & President, USA Division.

"The natural gas business will continue to be about lowering costs and maximizing margins. In our new world of abundant North American natural gas supply it will be even more important to be a low-cost producer and to have positions in the lowest cost basins – an approach upon which we have built our company," says Wojahn.

Encana's approach has delivered solid, measurable results. In 2009, the company achieved combined operating and administrative costs of $1.11 per thousand cubic feet equivalent (Mcfe). Encana's pro forma finding and development cost of $1.62 per Mcfe represents a decrease of approximately 25 percent from 2008. The three-year average finding and development cost was approximately $1.92 per Mcfe. The company expects to see a downward trend in finding and development costs over the coming years as it continues to improve on cost structures and focus operations in the lowest cost plays.



SHERRI BRILLON,
EXECUTIVE VICE-PRESIDENT &
CHIEF FINANCIAL OFFICER,
ENCANA

And it's only just begun. With continued advancements in drilling and completion technologies for extracting natural gas from shales, tight sandstones and coalbed methane reservoirs, there is the potential for further breakthroughs in development costs. With these advancements integrated within Encana's gas factory approach to the business and leveraged across its vast portfolio, the company is excited about the additional economies of scale that can be achieved.

STRONG BALANCE SHEET = SUSTAINABLE FUTURE

Encana believes that sustainability applies not only to environmental stewardship and corporate citizenship, but also to financial performance. Underlying Encana's sustainable growth strategy is a strong balance sheet and a disciplined approach to capital investment that is reinforced by prudent risk management practices.

Reflecting on the past year, Sherri Brillon, Executive Vice-President & Chief Financial Officer, says that "capital discipline, a cornerstone of Encana's culture, is what led to our strong 2009 financial performance and balance sheet. Despite the commodity price volatility and recessionary pressures, our balance sheet remains strong and we continue to employ a conservative capital structure. Debt-to-adjusted EBITDA, calculated on a pro forma basis, finished the year at 2.1 times and debt-to-capitalization at December 31, 2009 was 32 percent, despite having $2.5 billion in cash on hand net of current tax obligations. Net of working capital, these ratios would be 1.7 times and 27 percent, respectively."

PRUDENT RISK MANAGEMENT AND STRONG CASH FLOW

Encana's focus on active portfolio management and a prudent commodity price hedging program helped the company emerge from the worldwide economic downturn with a sharpened competitive focus and strong balance sheet. The goal of Encana's hedging program is to reduce exposure to movements in commodity prices and bring greater predictability to future cash flow generation. Encana's exposure to the commodity price weakness experienced in 2009 was substantially mitigated by its price hedges which contributed close to $2.3 billion to cash flow, on a pro forma basis, after tax. "Critical to our successful transition to a pure-play natural gas company was our risk management practices. In 2009, commodity price hedges allowed us to execute our capital programs, generate free cash flow of more than $1.3 billion and maintain our dividend. Our current quarterly dividend of 20 cents per share represents an attractive yield of

This robust resource base, concentrated in many of North America's lowest cost natural gas basins, is the source of an organic drilling inventory totaling about 35,000 locations.

about two percent, about twice that of our peer group, another point that sets us apart from our competitors," says Brillon.

Looking ahead, Encana expects that natural gas prices will continue to fluctuate although likely with dampened volatility as compared to the past. The company believes the long-term marginal supply cost of natural gas will set the natural gas price on the New York Mercantile Exchange (NYMEX) in the range of $6.00-$7.00 per thousand cubic feet (Mcf). Despite this lower range of prices, as compared to historical industry forecasts, Encana's portfolio of investment opportunities is projected to deliver strong returns. "We're confident that our current portfolio of new capital projects will achieve cost of capital returns at a NYMEX natural gas price of approximately $4.00 per Mcf and a very robust 40 percent rate of return at the midpoint of the expected future price range. In the shorter term, our view is that there are factors at play that see lower prices persist through the next few years. As such, we've extended our risk management program through 2010 by hedging about 2 billion cubic feet (Bcf) of our expected natural gas production at an average NYMEX price of $6.05 per Mcf. This helps to provide an increased level of certainty to our cash flow before we decide on the size of capital program we undertake," says Brillon.

Supported by prudent risk management initiatives and strong operational and financial performance through a challenging recessionary period, Encana has demonstrated that its resource play model is extremely successful and the company is well positioned for the future. "Our strategy of pairing low-risk, low-cost, North American resource plays with a strong balance sheet and favourable commodity price hedges has allowed us to be resilient through the lowest part of the commodity price cycle and maintain our position of strength. That discipline is paying off now more than ever, providing us with the financial capacity and confidence to target a doubling of Encana's size over the next five years on a per share basis," says Brillon.

IN TUNE WITH THE MARKET

The dynamic natural gas industry is facing many challenges and opportunities. Abundant, low-cost North American natural gas supply represents a major paradigm shift from where the industry was just a few years ago. Renee Zemljak, Executive Vice-President, Midstream, Marketing & Fundamentals, knows that as a pure-play natural gas company, Encana has to be in tune with natural gas markets to manage risk in advance of changing supply and demand. And the company is well positioned to do just that. The breadth of Encana's portfolio across North America provides the company with tremendous insight into natural gas market fundamentals. This information allows Zemljak's team to secure gas markets that are expected to provide the highest netback for Encana's production. Consistent with the company's low-cost goals, Zemljak and her team negotiate and secure cost competitive processing and transportation agreements that provide sufficient market access to deliver Encana's growing production volumes.

RENEE ZEMLJAK, EXECUTIVE VICE-PRESIDENT, MIDSTREAM, MARKETING & FUNDAMENTALS, ENCANA

With an abundant supply of natural gas at expected lower and less volatile prices, there is a clear opportunity for demand growth from traditional customers as well as from new ones. Zemljak explains that "this rapid change in natural gas availability and expected lower prices may take a while to be fully understood by the energy marketplace, but when it is, there is a huge potential for the expansion of end-use demand. We have a clean, affordable, North American energy solution and it is our role to disseminate that message and expand the pathway to market."

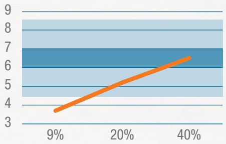
POISED TO WIN

Encana has a robust base of operating assets, a huge inventory of low cost undeveloped assets and a solid financial position that, together with its internal value-driven culture, provide a foundation for strong double-digit future growth potential.

Recognizing that natural gas is now likely to be both more abundant and more affordable, there is an opportunity for natural gas to play an even bigger role in the North American energy equation. Exciting opportunities and changes lie ahead and Encana will continue to play a leading role.

As Randy Eresman, Encana's President & CEO says, "The North American natural gas game has changed! Encana has the people, the assets and the strategy to win."

After-Tax Internal Rate of Return and Expected Range of Natural Gas Prices ($/MMBtu)



Lower long-term natural gas price in the **$6.00-7.00/MMBtu** range based on 2010F input costs.

- After-Tax Internal Rate of Return
- Expected Range of Natural Gas Prices

Endnotes in articles can be referenced on page 145

ENCANA CONTINUES TO SOLIDIFY ITS PRESENCE IN SEVERAL OF THE MOST EXCITING SHALE AND TIGHT GAS PLAYS IN NORTH AMERICA: THE HAYNESVILLE IN LOUISIANA AND TEXAS, HORN RIVER IN NORTHEASTERN BRITISH COLUMBIA AND MONTNEY IN NORTHWESTERN ALBERTA AND NORTHEASTERN BRITISH COLUMBIA.

Encana's Emerging Resource Plays

Encana is leading the technology revolution by continuously improving its drilling and completions practices. It is experiencing a downward step-change in production costs, while, at the same time, bringing larger natural gas supplies on stream more quickly. This manufacturing approach is key to the future of the natural gas business.

429,000
APPROXIMATE NET ACRES

about **115** total net producing wells by end of 2010

about **400** MMCF/D by end of 2010

DRILLING INVENTORY **3,500** net wells

about **22** total net producing wells by end of 2010

about **100** MMCF/D by end of 2010

256,000 APPROXIMATE NET ACRES

DRILLING INVENTORY **600** net wells

APPROXIMATE NET ACRES
720,000

about **325** MMCF/D by end of 2010

about **380** total net producing wells by end of 2010

DRILLING INVENTORY **2,600** net wells

HAYNESVILLE SHALE

Following the success of its Deep Bossier play in East Texas, Encana continued to explore for natural gas in other shale and tight gas opportunities along the same geologic trend. In 2005, Encana identified the Haynesville shale as an exciting opportunity and quietly began assembling a sizeable land position.

Formed roughly 150 million years ago and more than 10,000 feet beneath the Earth's surface, the Haynesville shale was originally considered too costly to develop because of the low permeability of the rock. Thanks to newer extraction technology, the Haynesville shale is now widely considered one of the most promising natural gas resource plays in North America.

In 2009, Encana doubled its capital program at Haynesville to $580 million. In 2009, the company drilled 88 wells in the area with a joint venture partner, yielding a 300 percent production increase to around 70 million cubic feet per day (MMcf/d). In anticipation of increased production from the region, Encana has participated in supporting the addition of processing facilities and pipelines that will continue to help the company deliver growing gas production to markets.

In 2010, Encana's primary focus will be on land retention and completion optimization. The company expects to drill approximately 100 net wells and exit the year producing about 400 MMcf/d.

HORN RIVER SHALE

Horn River represents an example of cross-company knowledge-sharing, which helped Encana gain a strong position in this emerging opportunity. Encana's Fort Worth team assisted in interpreting intriguing results from a northeast British Columbia well-log and shared knowledge on hydraulic fracturing practices. The result? Another early entry into what is quickly gaining recognition as a promising shale gas opportunity.

Since 2006, Encana and its partner have acquired a large land position in the heart of this emerging gas play in the Devonian Shale.

The Horn River Basin lies about 60 miles northeast of Fort Nelson, British Columbia. With a basin-wide estimated 500 Tcf of natural gas in place, Horn River has the potential to become another leading production centre for Encana.

Encana is confident Horn River will deliver strong returns by applying its proven gas manufacturing approach; in Horn River, Encana will be drilling 21 wells and completing 400 stages per pad. The company has doubled the per hydraulic fracture fluid volume from 500,000 gallons to 1 million gallons. Innovative composite materials enable multiple fracturing operations in one day and advanced coil tubing technologies have allowed for repeated complex operations on longer reach wells. The combination of efficiencies and technology advancements is driving costs down to approximately 25 percent of what they were a couple of years ago.

In 2010, the company expects to increase production from 13 MMcf/d to more than 100 MMcf/d by year-end.

MONTNEY TIGHT GAS

The Montney formation, at Cutbank Ridge, is a tight gas play in northeast British Columbia and it extends over the border into Alberta. This region has been producing conventional oil and gas since 1998. More recently, the focus has been on large accumulations of natural gas associated with the Cadomin and Montney formations.

Encana began assembling a land position in this area in 2003, once again a front runner in identifying the potential opportunity. Now, with more than 720,000 net acres of land with Montney rights, and approximately 244,000 net acres located within the core development area near Dawson Creek, British Columbia, the region has emerged as an exciting opportunity for future production growth for Encana.

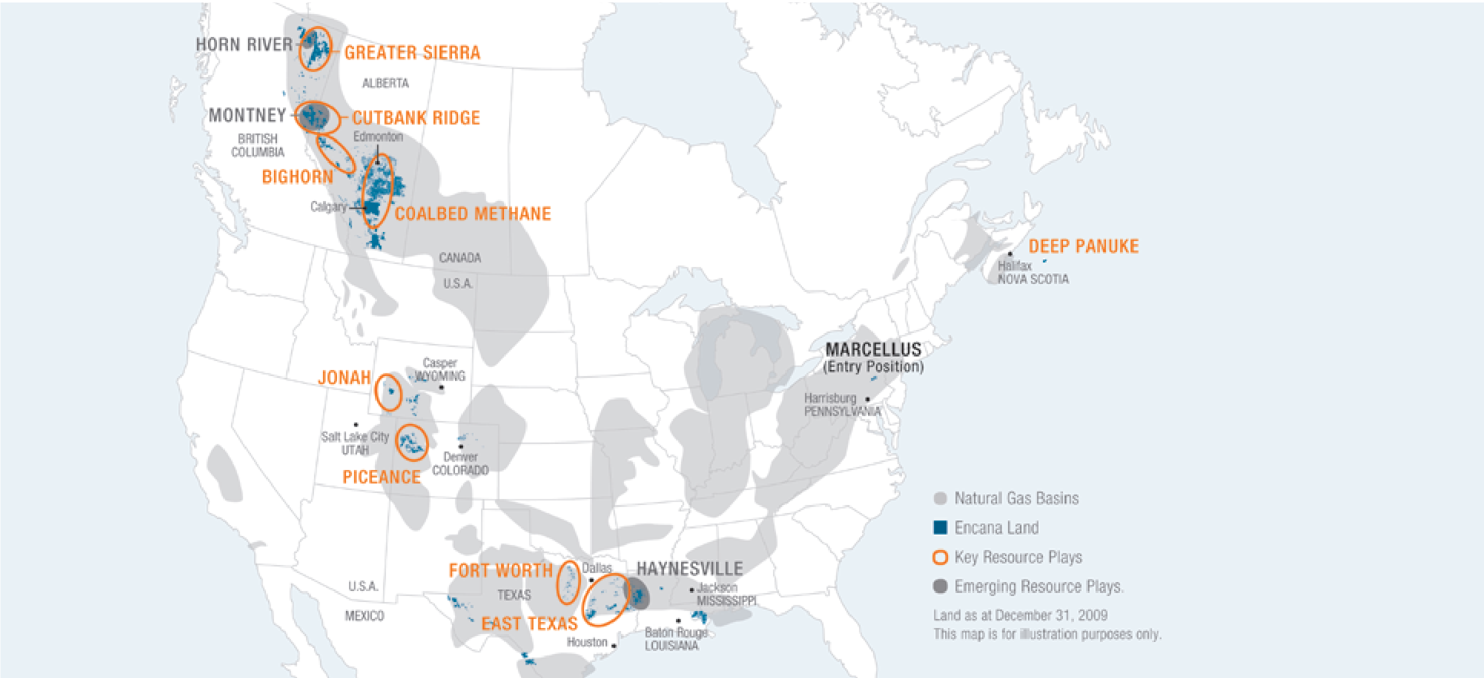
The Montney is a world-class resource play, which is being almost exclusively developed with horizontal well technology. Applying new drilling and fracturing technology has enabled Encana to increase the horizontal reach from 3,000 to 6,000 feet and its hydraulic fractures per horizontal well from eight to 14, thereby increasing the wells' initial production from 5 to 10 MMcf/d. In 2009, Encana drilled 68 natural gas wells in the area and production averaged approximately 180 MMcf/d of natural gas from the Montney formation.

In 2010, Encana plans to continue its steady development of the Montney formation. The company has tremendous development opportunities in this key resource play, with approximately 2,500 future drilling locations identified.

Encana expects to drill approximately 42 net wells in 2010 and exit the year producing about 325 MMcf/d from the Montney formation.

HOLDINGS AND OPERATIONS

NORTH AMERICA / NATURAL GAS AND ENCANA OPERATIONS



BIGHORN / CANADA

- Primarily sweet natural gas wells
  – tight gas multi-zone Cretaceous play
- New wells produce between 2 MMcf/d and 10 MMcf/d
  – drilled approximately 70 net wells in 2009
  – approximately 460,000 net acres
  – drilling inventory of about 1,100 net wells

COALBED METHANE (CBM) / CANADA

- CBM is natural gas held in coal or porous rock formations
- Encana applies more than 40 years of experience in producing natural gas from shallow reservoirs
- Most CBM activity focused on the dry coal seams of the Horseshoe Canyon formation
  – drilled approximately 490 net wells in 2009
  – approximately 5.1 million net acres including about 2.1 million net acres on the Horseshoe Canyon trend
  – drilling inventory of about 14,000 net wells

CUTBANK RIDGE / CANADA

- This tight gas reservoir resource play is located in northeast British Columbia and northwest Alberta. The focus is on long-term growth using the latest extraction technology to produce gas from the Montney, Cadomin and Doig geological formations
  – drilled approximately 70 net wells in 2009
  – approximately 1.1 million net acres
  – drilling inventory of about 2,700 net wells

GREATER SIERRA / CANADA

- Located in northeastern British Columbia, this play is focused on continued development of the Jean Marie geological formation and Horn River Basin; to date, Encana has developed approximately 30 percent of the asset
  – began implementing multi-lateral horizontal drilling, which resulted in increased well performance and improved cost structures
  – drilled approximately 55 net wells in 2009
  – approximately 1.8 million net acres
  – drilling inventory of about 1,400 net wells

DEEP PANUKE / CANADA

- Deep Panuke project involves installation of facilities (offshore drilling pad and pipeline) to produce and process natural gas from the Deep Panuke field, approximately 250 kilometres (156 miles) southeast of Halifax, Nova Scotia on the Scotian Shelf
- Natural gas will be processed offshore and transported via subsea pipeline to Goldboro, Nova Scotia for further transport to market via the Maritimes & Northeast Pipeline
- First gas is expected from Deep Panuke in 2011

ESTABLISHED POSITIONS IN EMERGING PLAYS / KEY STATISTICS

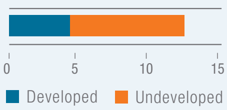
Encana Play	ECA Basin Entry Year	ECA Acres (Net)	Basin Natural Gas In Place (Bcf/Section)	Vertical Drill Depth (Feet)	Estimated Gas In Place* (Tcfe)	Well Drilling Inventory (Net)	Indicative IP (MMcf/d)
Haynesville	2005	429,000	175-225	12,000	120	3,500	15
Horn River	2003	256,000	150-270	9,000	50	600	10
Montney	2003	720,000	50-200	9,000	165	2,600	10
Maverick Pearsall	2005	245,000	125-175	9,000	50	TBD	5
Piceance Niobrara	2006	610,000	100-200	9,000	100	TBD	6

* On Encana lands

12.8 TCFE
TOTAL PROVED RESERVES

12.7
MILLION TOTAL NET ACRES IN NORTH AMERICA

Developed and Undeveloped Net Acres (millions)



EAST TEXAS / UNITED STATES

- This play targets the Bossier and Cotton Valley zones; characteristics are similar to plays in the Rocky Mountains: a tight gas, multi-zone play requiring careful application of technology to unlock the gas
  - drilled approximately 40 net wells in 2009
  - approximately 265,000 net acres
  - drilling inventory of about 800 net wells

FORT WORTH / UNITED STATES

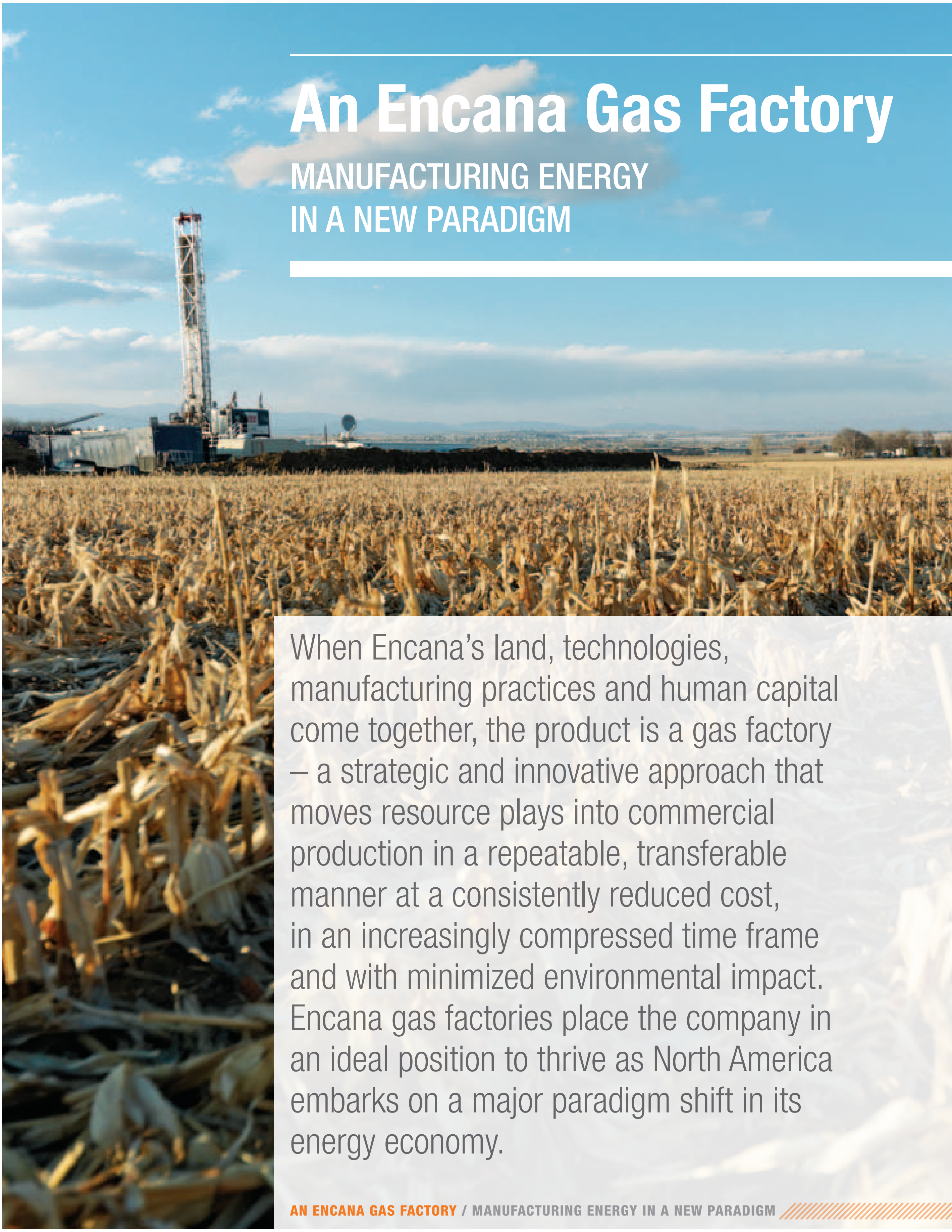
- Located in north Texas, the Fort Worth resource play stretches underground across a 15-county area; the play includes the Barnett shale in the Fort Worth Basin
  - drilled approximately 27 net wells in 2009
  - approximately 76,000 net acres
  - drilling inventory of about 1,100 net wells

PICEANCE / UNITED STATES

- Encana entered the Piceance Basin in Colorado in 2001 with the acquisition of Mamm Creek field, and added to its position by acquiring Tom Brown Inc. in 2004
- The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation
  - drilled approximately 130 net wells in 2009
  - approximately 870,000 net acres
  - drilling inventory of about 5,100 net wells

JONAH / UNITED STATES

- Encana entered the Jonah field, located south of Pinedale, Wyoming, in 2001. Production is from the Lance formation, which contains vertically stacked sands that exist at depths between approximately 2,600 and 4,000 metres (approximately 8,500 and 13,000 feet)
- The wells are stimulated with multi-stage advanced hydraulic fracturing techniques. The life of the Jonah field is estimated to be from 40 to 60 years
  - drilled approximately 110 net wells in 2009
  - approximately 125,000 net acres
  - drilling inventory of about 2,200 net wells

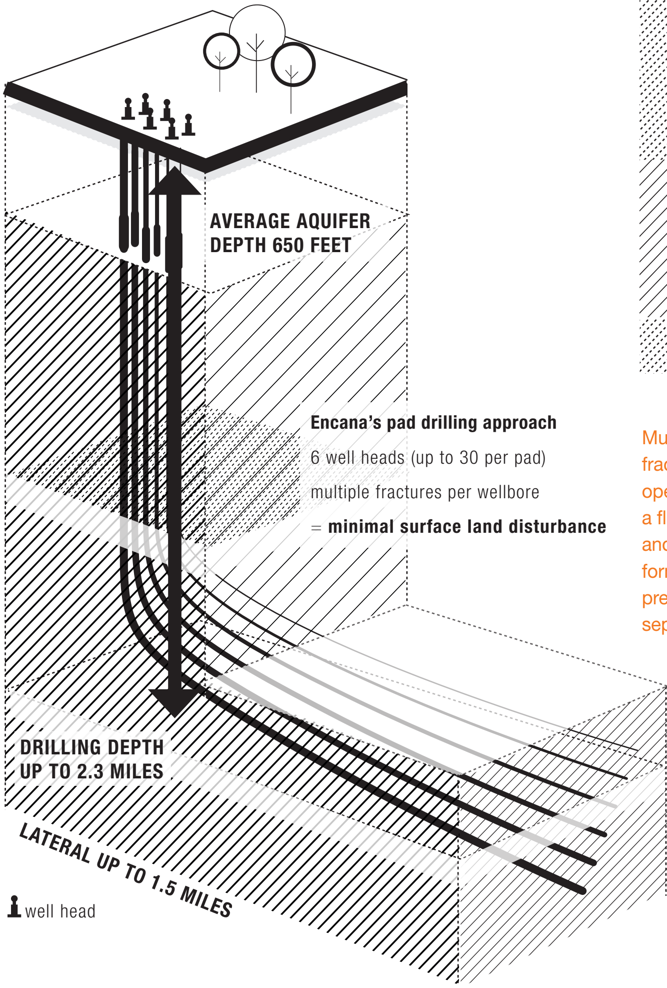


An Encana Gas Factory

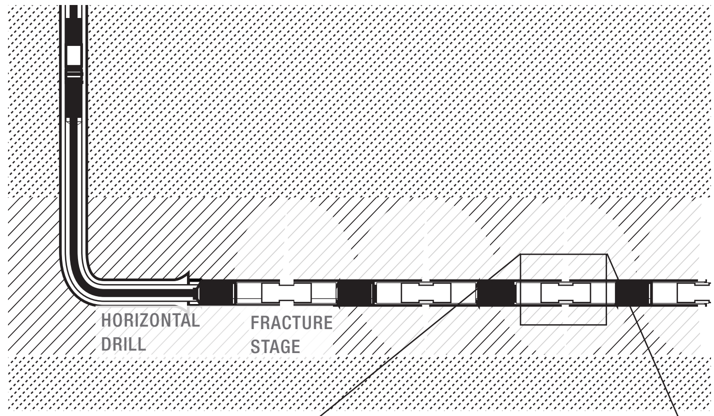
MANUFACTURING ENERGY IN A NEW PARADIGM

When Encana's land, technologies, manufacturing practices and human capital come together, the product is a gas factory – a strategic and innovative approach that moves resource plays into commercial production in a repeatable, transferable manner at a consistently reduced cost, in an increasingly compressed time frame and with minimized environmental impact. Encana gas factories place the company in an ideal position to thrive as North America embarks on a major paradigm shift in its energy economy.

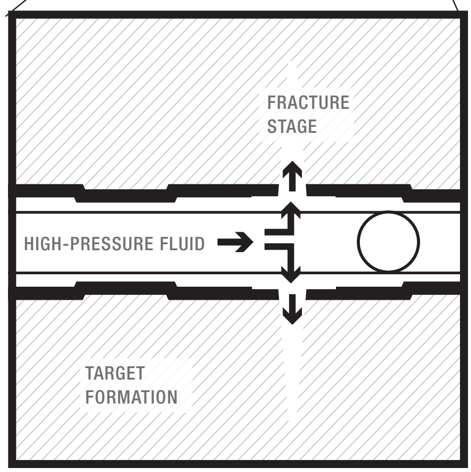
REDUCED FOOTPRINT



MULTI-STAGE HYDRAULIC FRACTURING



Multi-stage hydraulic fracturing is a controlled operation that pumps a fluid, primarily water and sand, into a target formation at high pressure in up to 20 separate intervals or fracture stages. By drilling horizontally through a reservoir, fracture stages can be added and gas production for each well increased.



UNLOCKING RESOURCE PLAYS

Hydraulic fracturing is a controlled operation that pumps a fluid (primarily water) and a propping agent (sand) through the wellbore to the target formation at a high pressure in multiple intervals, or stages. The process breaks up the target formation, much like a stone fracturing a windshield, to create pathways that allow the gas to flow from the very low permeability reservoir toward the wellbore. Resource plays typically extend across a vast area of an underground formation, where each square mile of the target reservoir is highly gas charged. These resource plays are an ideal fit for the gas factory development approach.

TWIN EFFICIENCY GAINS

Although each unconventional gas field has unique surface and subsurface challenges, the application of long-reach horizontal drilling and multi-stage hydraulic fracturing enables two major efficiency gains. First, *"By employing our gas factory development approach across our prolific asset portfolio, we are able to achieve sustainable production growth of low-cost unconventional gas supplies and strong value creation for years ahead."*

JEFF WOJAHN,
EXECUTIVE VICE-PRESIDENT & PRESIDENT,
USA DIVISION, ENCANA

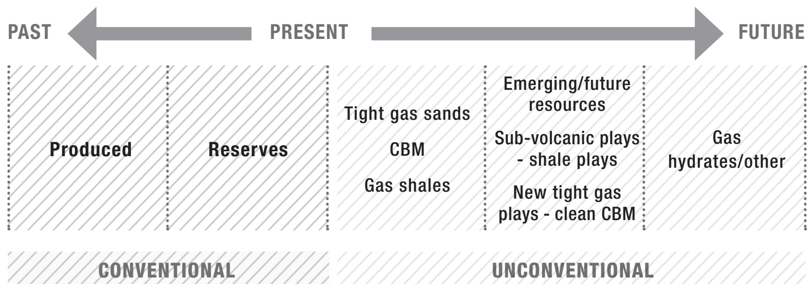
drilling long horizontal wells through a reservoir achieves multiple-fold increases in exposure to the sedimentary formation. Compared to vertical wells, horizontal drilling intersects vastly more resource without the incremental cost of the vertical portion of the well. Second, by drilling from multi-well pads, at times more than 30 horizontal wells from a single location, the surface land occupied by rigs and production equipment is a fraction of conventional methods. Multi-well pads occupy a very low percentage of the land that typically would be used by vertical wells accessing the same subsurface development area. This gas factory is able to recover more natural gas at a lower cost and with dramatically reduced surface occupancy.

In the Horn River basin in northeast British Columbia, up to 16 wells are being drilled from one surface location to develop a reservoir underlying up to four square miles of land. Oftentimes, there are multiple subsurface sedimentary formations, stacked on top of each other, that can be reached from a single location. This layer-cake of resource is well suited to support long-term, strong-return developments. The result is increased efficiency and lower environmental impact.

UNCONVENTIONAL TECHNOLOGIES AND OPERATIONAL EFFICIENCIES IN THEIR INFANCY

Operational efficiencies are realized as drilling rig moves are minimized, multi-well completion and production operations are conducted in a continuous fashion and pad well site facilities are shared. Over the past few years, Encana has worked with drilling companies to custom build fit-for-purpose rigs designed for projects with specific geological and geographical requirements. Encana utilizes close to 100 percent fit-for-purpose rigs across its operations, where safety, reduced environmental impact and efficiency are foremost priorities. In northern locations such as Horn River, where winter historically slowed activity, Encana's manufacturing approach allows for year-round

THE RESOURCE PLAY ADVANTAGE



operation. With the advent of horizontal drilling and multi-stage hydraulic fracturing, per-treatment costs are dropping significantly. "Technology is moving quickly and major advancements are likely over the next several years as we are still in the infancy of optimizing the efficiency of horizontal drilling and multi-stage hydraulic fracturing," says Mike Graham, Encana's Executive Vice-President & President, Canadian Division.

GAS MANUFACTURING FUTURE

"With each well we drill, each multi-pad lease we build, each hydraulic fracture treatment we complete, we get better, learn more, capture operational efficiencies and drive down the per-unit cost of every molecule of natural gas we produce," says Jeff Wojahn, Encana Executive Vice-President & President, USA Division.

In the Piceance basin of Colorado, Encana is already planning small multi-well pads that occupy just a few acres, yet drill up to 60 wellbores from one location. When rigs or hydraulic fracturing crews only have to move a short distance to their next job, and can complete several jobs in sequence, the time-tested laws of specialized labour practices yield significant benefits. When supplies such as sand and drill pipe can be delivered in bulk to single locations, economies of scale enhance the value of every Encana share. New efficiencies are being realized through simultaneous operations where drilling is underway on one cluster

HAYNESVILLE PLAY

40

PERCENT REDUCTION

in drilling, completion and tie-in costs due to the application of advanced technologies in 2009.

Types of Unconventional Gas

Tight Gas
Natural gas stored in small pore spaces in very low permeability underground formations, such as sandstone, siltstone or limestone.

Shale Gas
Natural gas stored in extremely small pore spaces or bonded to organic material within rock composed mostly of consolidated clay and siltstone.

Coalbed Methane (CBM)
Natural gas stored in naturally occurring fracture systems or bonded onto the coal.

> *Technology is moving quickly and major advancements are likely over the next several years as we are still in the infancy of optimizing the efficiency of horizontal drilling and multi-stage hydraulic fracturing.*

MIKE GRAHAM,
EXECUTIVE VICE-PRESIDENT & PRESIDENT,
CANADIAN DIVISION, ENCANA

of wells, hydraulic fracturing on another and production tie-ins on a third group, all residing within the same gas factory pad. Encana has repeatedly found that through a determined and disciplined focus on continually improving core tasks, new operational efficiencies are realized. So while horizontal drilling allows the company to drill wells that reach close to two miles in opposing directions, highly trained crews are looking for new ways to deliver clean natural gas cheaper.

ENVIRONMENTAL STEWARDSHIP

As a leading corporate citizen, Encana takes pride in being a good steward of the environment. In unconventional gas development, as with all resource production, effectively managing water resources is critical to extracting the resource in an economical and responsible manner.

RESPONSIBLE WATER MANAGEMENT

Water and sand are the primary components of the fluids used in hydraulic fracturing. In addition, third-party service providers, in consultation with producers, use highly diluted volumes of chemical additives to ensure effective fracturing of the target reservoir and recovery of fluids. In all Encana operations, rigourous water management and conservation is a vital part of this process. It all begins with proper wellbore design.

WELLBORE DESIGN

Every natural gas well has a steel casing that is cemented externally to prevent fluids migrating from the wellbore and to protect local groundwater. Typically, thousands of feet of rock separate the target formations from any fresh or potable aquifers. Even with those safeguards in place, Encana uses multiple techniques to fully understand the effect of each hydraulic fracture treatment it conducts. The company relies on groundwater experts to evaluate water sources and has designed a tailored approach to water management and protection at each drilling location.

As an example, although the Horn River play was initially tested using fresh water, the team identified saline, non-potable water sources from approximately 2,600 feet below the surface for use in hydraulic fracturing. This water is unfit for humans, animals or agriculture. In 2010, a new water treatment plant 60 miles northeast of Fort Nelson is expected to increase Encana's capacity to use this non-potable supply of water at its Horn River operations. As the first company in the basin to test a long-term water solution, Encana is applying leading-edge technology to minimize environmental impact and reduce costs.

RESPONSIBLE HYDRAULIC FRACTURING

Hydraulic fracturing is a safe and proven way to develop natural gas; it has been used throughout the oil and gas industry for about 60 years. Encana meets, and strives to exceed, the strict requirements for hydraulic fracturing processes set out by government regulatory agencies. All fluids that return to the surface are recycled or disposed of in regulatory agency-approved disposal wells. Encana is continuously seeking ways to improve its technologies and operations from an environmental perspective. Initiatives underway across all Canadian and U.S. operations help ensure that Encana is managing the use of hydraulic fracturing fluids responsibly.

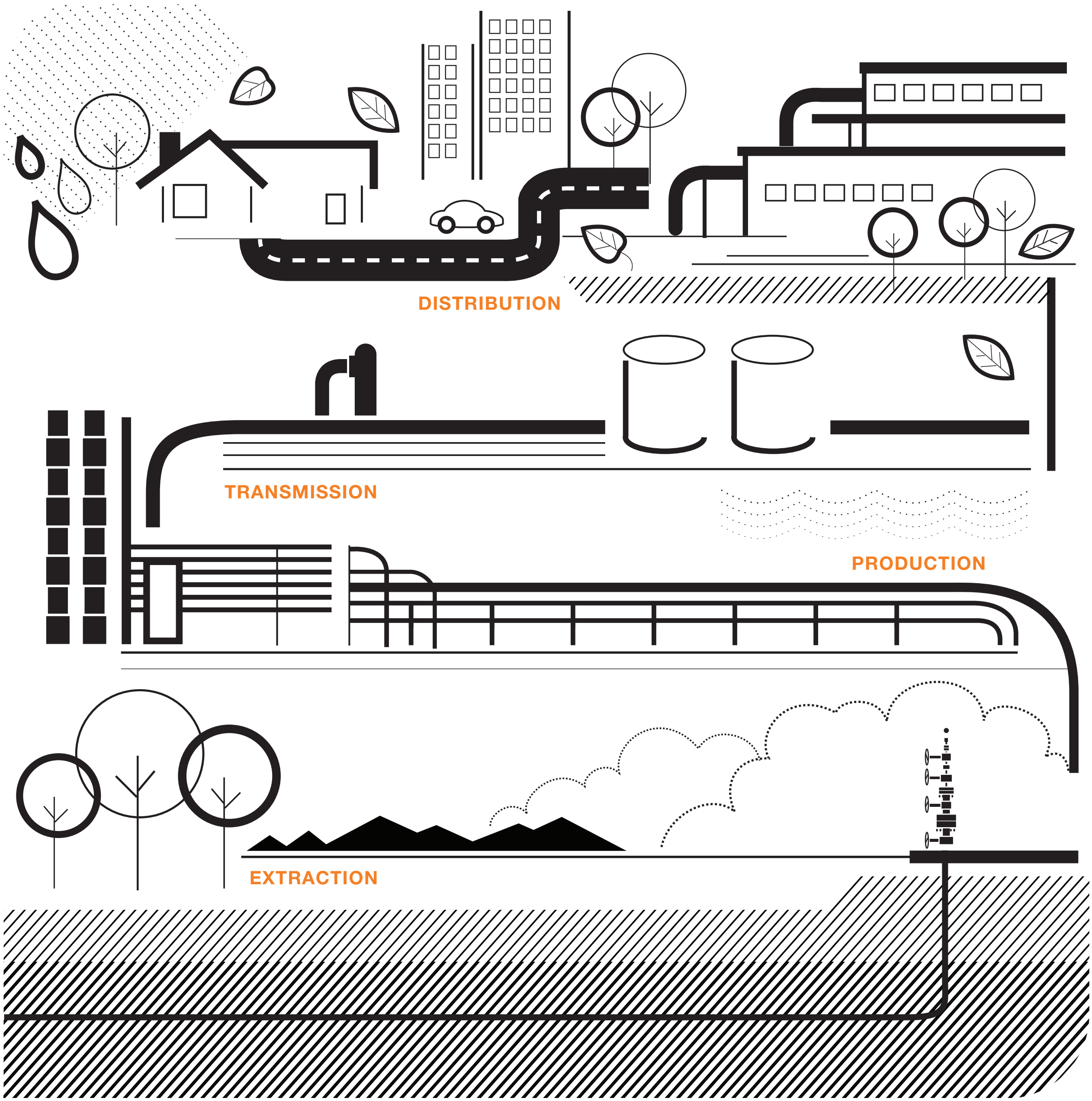
FUEL FOR THE FUTURE

Encana's focus on developing its prolific unconventional natural gas assets will have untold benefits for the future of North American energy supply. "As an early mover in establishing a leading land and resource position, Encana is North America's premiere, pure-play natural gas company. By employing our gas factory development approach across our prolific asset portfolio, we are able to achieve sustainable production growth of low-cost unconventional gas supplies and strong value creation for years ahead," Wojahn says.

An Abundant Domestic Source of Energy

nG/101 NATURAL GAS END USE

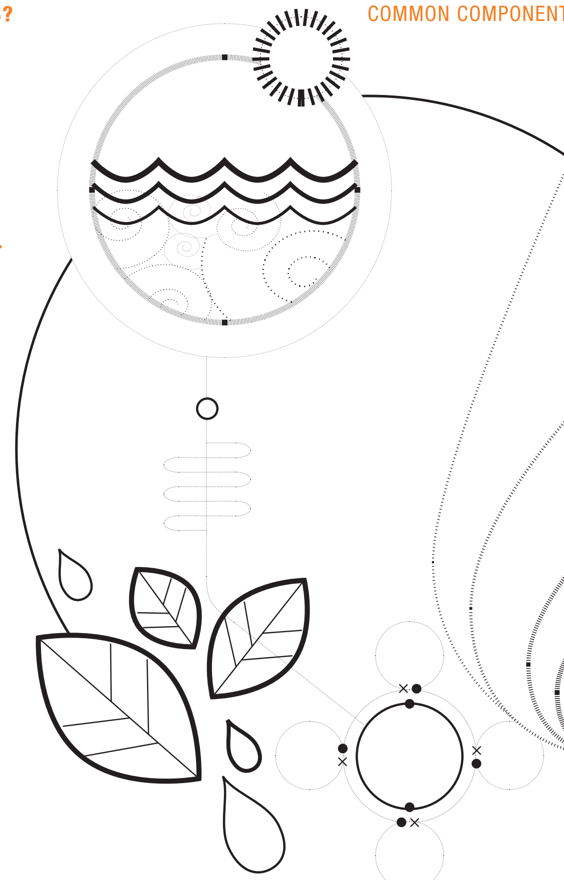
encana natural gas



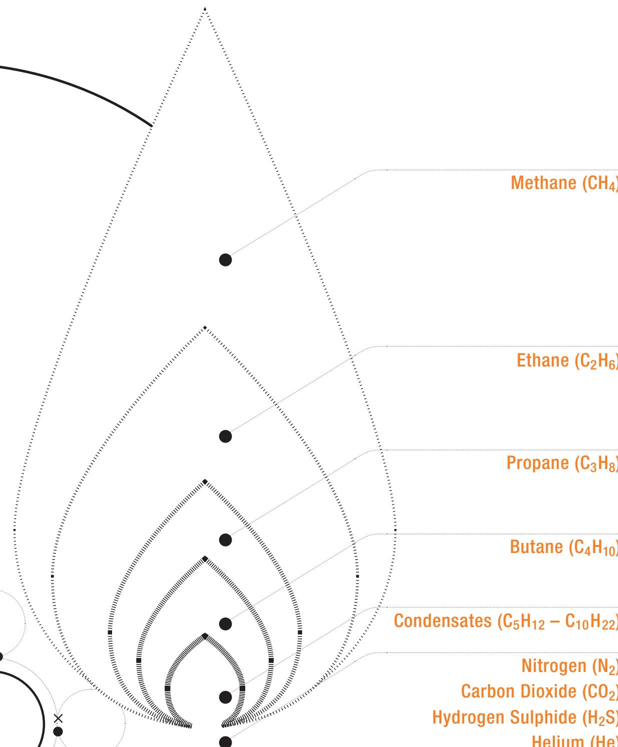
ng/101 NATURAL GAS END USE

WHAT IS NATURAL GAS?

Natural gas originated from the decomposition of organic matter under many layers of sediment deposits. Heat, underground pressure and other factors created chemical changes over time, forming hydrocarbons such as natural gas. The primary component of natural gas is methane – the chemical compound CH_4 – one atom of carbon and four hydrogen.



COMMON COMPONENTS OF UNPROCESSED NATURAL GAS



NATURAL GAS IS THE CLEANEST BURNING FOSSIL FUEL

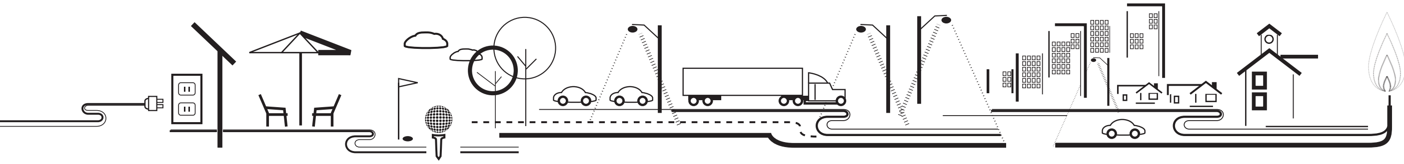
The main combustion byproducts are carbon dioxide (CO_2) and water vapour, the same compounds we exhale. Combustion produces 25 percent less CO_2 than oil and about 50 percent less than coal.[1] But because of higher efficiency power plants, this results in CO_2 emissions per kWh that are up to 65 percent less than coal.

Natural gas emits almost no particulates into the atmosphere: particulates from natural gas combustion are 90 percent lower than oil and 99 percent lower than coal combustion.[2]

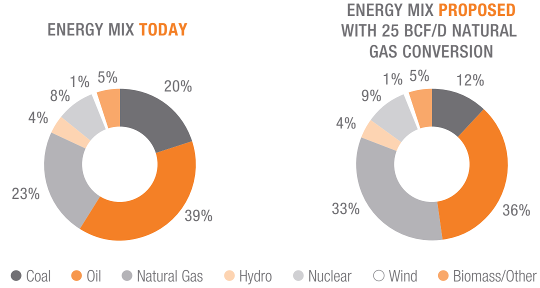
DIFFERENCE BETWEEN CNG AND LNG

Compressed Natural Gas (CNG): Natural gas condensed under high pressures – between 2,000 and 3,600 pounds per square inch (psi) – and held in a special, reinforced container; the gas expands when released for use as a fuel.

Liquefied Natural Gas (LNG): Natural gas converted temporarily to a liquid form for ease of storage or transport by cooling it to approximately -162°C (-260°F); [3] LNG takes up 1/600 of the volume of natural gas in a gaseous state.[4]

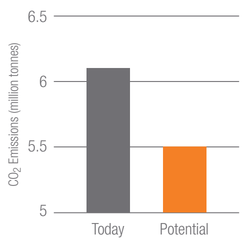


ENERGY MIX & EMISSIONS BY SOURCES: USA + CANADA



Source: EIA; StatsCan; Encana estimates

CO_2 EMISSIONS REDUCTIONS: WITH 25 BCF/D NATURAL GAS CONVERSION



Coal and oil displacement are approximately 1 million metric tons (2.2 billion lb) and 1.7 million barrels of oil per day respectively.

Natural gas is measured in millions, billions and trillions of cubic feet.

- 1 Bcf/d of natural gas could fuel 3.9 million midsized cars to travel 25,000 kilometres (15,000 miles) per year [5]
- 1 Bcf/d of natural gas = 8.3 million U.S. gallons or 31.5 million litres per day of gasoline equivalent

35 THOUSAND NORTH AMERICAN JOBS

35,000 North American jobs are created with each additional Bcf/d of production.[6]

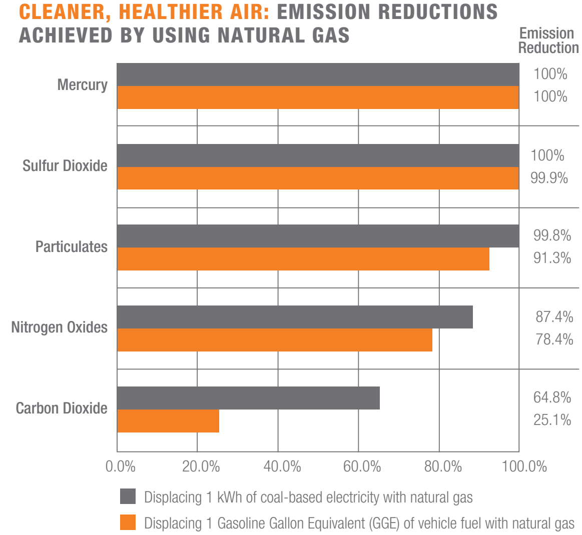
NATURAL GAS IS AN ESSENTIAL PART OF OUR DAILY LIVES

Canadians and Americans use more than 6.7 trillion cubic feet of natural gas annually[7] to heat and cool their homes, heat water, dry their clothing and cook their food.

- A very efficient fuel for cooking, 460 Bcf of natural gas is used in the kitchen each year [8]
- Although gas-powered appliances may currently be more expensive than electrical, they are cheaper to operate, have a longer expected life and require relatively low maintenance
- With 55 percent of homes using natural gas for space heating,[9] the natural gas delivery infrastructure is already in place, making it very simple and affordable to install natural gas appliances in those homes

Combined, Canada and the U.S. import approximately 45 percent of the crude oil they use.[10]

CLEANER, HEALTHIER AIR: EMISSION REDUCTIONS ACHIEVED BY USING NATURAL GAS



Endnotes in articles can be referenced on page 145.

ng/101 NATURAL GAS END USE

THE GROWTH PICTURE

Primary growth opportunities are in unconventional gas – natural gas from reservoir rocks that are less porous and permeable than conventional reservoirs.

Simply put, unconventional gas does not readily flow to the well bore. Examples are tight gas, shales and coalbeds.

Unconventional reservoirs were once thought to be too difficult to develop. Advanced technologies, such as horizontal drilling, hydraulic fracturing and multi-lateral wellbores, have made it possible to profitably unlock these reservoirs at lower and lower costs. Now about 40 percent of current North American natural gas production is from unconventional sources.[11]

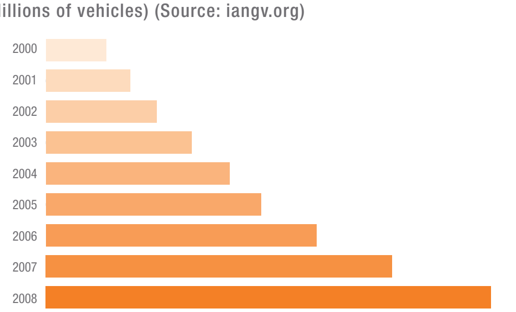
By 2020, it is expected that nearly 70 percent of Canadian and American natural gas will be from unconventional reservoirs.[12]

NATURAL GAS PROVIDES FUEL FOR

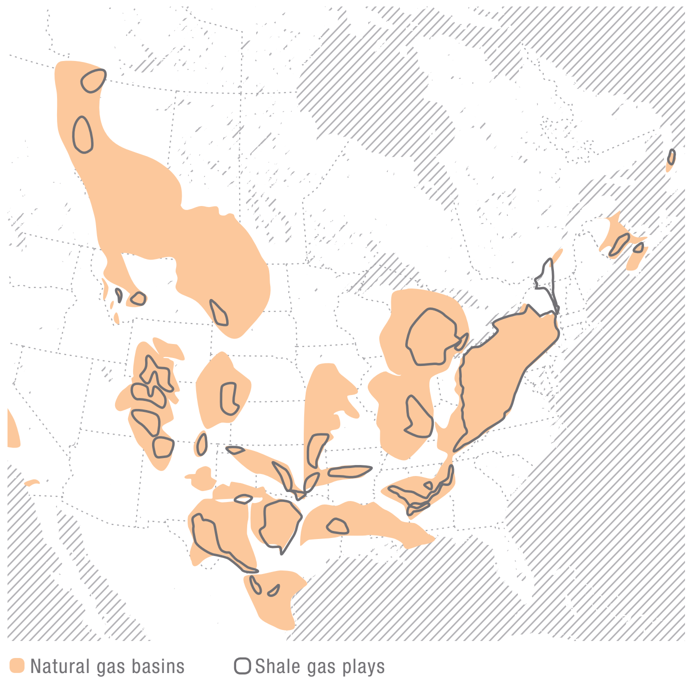
10 MILLION VEHICLES[13]

and is considered safer and cheaper than gasoline.[14]

Natural Gas Vehicles Yearly Growth Worldwide
(Millions of vehicles) (Source: iangv.org)



NATURAL GAS IS ONE OF NORTH AMERICA'S MOST VALUABLE RESOURCES



Combined, Canada and the U.S. have approximately 100[15] years of clean-burning, abundant, affordable natural gas.

NATURAL GAS IS A CLEAN AND EFFICIENT SOURCE OF ELECTRICITY

It takes 60 percent more coal than natural gas to produce one kilowatt-hour of electricity.[16]

Even if coal generation were as efficient, natural gas would still have almost 50 percent lower CO_2 emissions, 99 percent less sulphur dioxide (SO_2) emissions and zero mercury emissions.[17]

The most advanced coal plants (new technology for completion in 2012 to 2016) can achieve 38 percent efficiency.[18] They cost twice as much as advanced combined cycle natural gas plants to build and operate.[19]

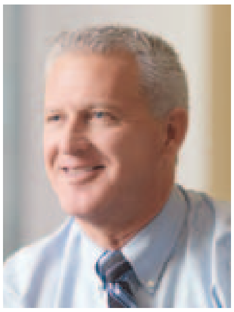
About 35 Bcf/d of natural gas in advanced combined cycle natural gas generation would displace all coal-based generation in the U.S. and yield emission reductions of about 50 percent in the electricity sector.[20]

What is combined cycle natural gas generation? Waste heat from gas turbine generated electricity is used to make steam, which is then used to fuel steam turbines to generate additional electricity, enhancing efficiency as a result.

Natural gas can help manufacture pretty much anything.
Including jobs.
From rocket science, to research or retail. In manufacturing, agriculture and health care.
Natural gas means more than jobs. Fact is, natural gas is helping create careers.
And we couldn't be prouder. **We are Encana.**
encana
natural gas
Learn more about natural gas and Encana at **www.encana.com**

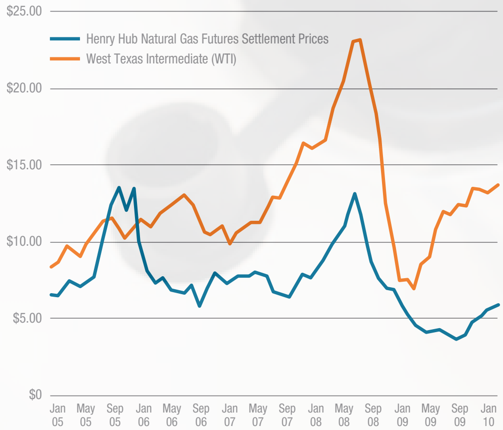
NATURAL GAS
the fuel for the 21st century

Combined, Canada and the U.S. have approximately 100[1] years of clean-burning, abundant, affordable natural gas sitting right beneath our feet. I see a natural gas renaissance in everyday life over the coming decade.



ERIC MARSH,
EXECUTIVE VICE-PRESIDENT,
NATURAL GAS ECONOMY, ENCANA

Monthly Average Henry Hub Natural Gas Futures Settlement Prices versus West Texas Intermediate (WTI) per MMBtu



Source: EIA
(Note: 2005 natural gas price spike due to Hurricanes Rita and Katrina.)

Encana believes natural gas will not only continue to be a vital component of the North American energy solution for the next 100 years, but also that it can immediately play a larger role in addressing energy security and environmental mandates.

Eric Marsh is Executive Vice-President, Natural Gas Economy at Encana, and he has a mandate to create new markets for the consumption of natural gas. "Establishing natural gas as the foundation of the North American energy portfolio benefits our economy and decreases emissions," says Marsh. Canada and the U.S. have approximately 100 years of clean-burning, abundant, affordable natural gas sitting right beneath our feet. I see a natural gas renaissance in everyday life over the coming decade." Legendary oil and gas entrepreneur T. Boone Pickens couldn't agree more.

Like Marsh, Pickens is on a mission. He is determined to wield his considerable influence to cut U.S. dependence on imported oil. Pickens believes the answer is natural gas.

North America has vast reserves of natural gas and advancements in extraction technology for unconventional natural gas. Combined, Canadian and U.S. natural gas production was approximately 70 Bcf/d[2] in 2009. America's Natural Gas Alliance (ANGA) estimates North American producers can add another 25 Bcf/d of supply in the next few decades.

Despite this abundance of North American natural gas, consumers continue to rely on large amounts of imported oil to fulfil their energy consumption needs. Combined, Canada and the U.S. import approximately 45[3] percent of the crude oil they use. Natural gas is a secure domestic solution that can reduce the need for oil imports.

Secure domestic supply is only one of the virtues of natural gas. On an energy-equivalent basis, abundant supplies of natural gas are available at less than half the price of a barrel of oil,[4] based on 2009 prices, making it by far the most affordable fuel for transportation. In recent years, compressed natural gas (CNG) and liquefied natural gas (LNG) have been 20 to 30 percent[5] less expensive than gasoline and diesel in many regions where they are used. These savings are expected to increase as more infrastructure and distribution networks are built to support higher demand.

NATURAL GAS FACTS

Canada and the U.S. have natural gas to last approximately 100 years[6].

- New technologies extract abundant volumes of natural gas from shales, coalbeds and tight sand reservoirs once thought to be uneconomic

Natural gas has been considered a fuel source for transportation since the 1860s.

- The first internal combustion engine vehicle to run on natural gas was built in the 1860s by Belgian inventor and engineer Etienne Lenoir.[7] The vehicle was first commercialized in Italy in the 1930s[8]
- Today, there are close to 10[9] million natural gas vehicles around the world and 1,100[10] natural gas fuelling stations in the U.S. alone

Natural gas vehicles have a stellar safety record.

- Vehicles fuelled by natural gas are as safe as, or safer than, gasoline-fuelled vehicles.[11] Natural gas is lighter than air and will quickly disperse if accidentally released. Also, fuel systems for natural gas vehicles are built to stringent standards

CNG and LNG are different.

- The difference between CNG and LNG is the manner in which they are stored. CNG is stored in special tanks that are highly pressurized, between 2,000 and 3,600 psi (pounds per square inch)
- LNG is stored as a super-cooled (cryogenic) liquid – typically between -184 and -274°F, depending on composition. This process makes it extremely portable and an attractive alternative for meeting global natural gas demand

CONVERTING COLORADO FLEET TO NATURAL GAS

Encana plans to convert 30 percent of its vehicle fleet in the southern Rockies region to bi-fuel vehicles – able to run on either natural gas or gasoline – by the end of 2011.

Natural gas is used in many parts of the world in both gas and liquid forms for transportation but, as Marsh points out, “North America is well behind our counterparts in Europe in manufacturing and using natural gas vehicles, and there is no reason we should be. With our abundant supply of this clean, domestic resource, we have massive room for growth.”[12]

Encana is leading by example and switching some of its vehicle fleet to natural gas over the next few years. Additionally, Encana is seeing the benefits of natural gas as a preferred fuel in daily operations. It now has gas-fired electricity at its Jonah field in Wyoming and is operating three rigs in Canada on dual fuel (70 percent natural gas, 30 percent diesel). Eight rigs previously fuelled by diesel have been converted to natural gas in its North Rockies region, resulting in a 25 percent[13] reduction in emissions and a 40 to 60 percent reduction in fuel costs.

Almost twice as clean as coal, natural gas produces fewer pollutants than other fossil fuels. It is composed primarily of methane (CH_4) – the main products of natural gas combustion are carbon dioxide (CO_2) and water vapour, the same compounds we exhale when we breathe. And, the combustion of natural gas emits almost 25 to 50 percent less CO_2 than oil and coal, respectively.[14] Sulphur dioxide (SO_2), nitrogen oxides (NO_X) and particulates from natural gas are extremely small compared to those generated by coal and oil, making for cleaner, healthier air.

What’s more, natural gas efficiency for electricity generation is higher than coal. The most advanced combined cycle gas plants can reach 50 percent[15] efficiency versus traditional coal at 30 percent.[16] In this model, natural gas provides a 20 percent improvement to the efficiency rate for power generation. This higher efficiency results in CO_2 emissions per kilowatt hour that are up to 65 percent[17] less than coal.

> “There’s a lot of talk about moving to the battery to power our cars. A battery won’t move an 18-wheeler. The best fuel to get us off imported oil, gasoline and diesel is North America’s abundant supplies of cleaner, cheaper natural gas.”
>
> T. BOONE PICKENS,
> OIL AND GAS ENTREPRENEUR

With advanced technologies and processes requiring fewer wells and a smaller land footprint to extract greater amounts of natural gas, Marsh reiterates that the growth opportunity in North America is enormous.

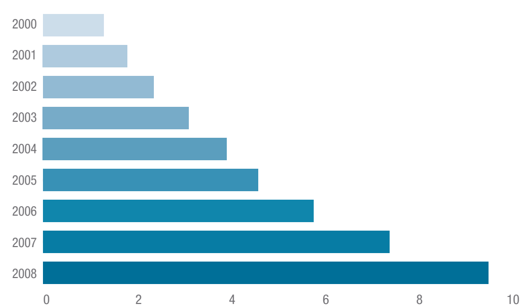
“One might wonder why, with all its benefits, natural gas isn’t already a much bigger part of the North American energy solution. Rapid advancements in technology have recently allowed for the economic extraction of huge quantities of unconventional gas at lower and lower costs. We’re now at the beginning of a new chapter in the story of natural gas,” Marsh says.

Endnotes in articles can be referenced on page 145.

“Conversion is another step to reducing our environmental footprint,” says David Hill, Vice-President, Natural Gas Economy Operations. “We’re also taking this opportunity to educate the public about natural gas as a fuel alternative for transportation.” Hill notes that public acceptance of natural gas as an alternative will increase demand and support installation of natural gas pumps at service stations.

“We’re confident other operators of fleet vehicles will agree it makes economic and environmental sense,” says Hill. Encana is also investigating the conversion of vehicles in other areas of the business.

Natural Gas Vehicles Yearly Growth Worldwide
(Millions of vehicles) (Source: iangv.org)



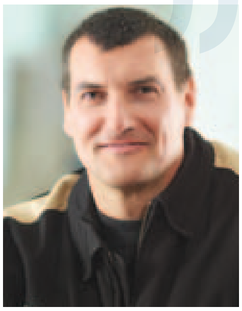
RISING TO THE CHALLENGE

We are firm in our commitment to safety as a core value across our operations.

38 PERCENT DECREASE FROM 2008 – 2009
of lost time injury frequency (employees and contractors)

15 PERCENT DECREASE FROM 2008 – 2009
in recordable injury frequency (employees and contractors)

Across the company, our various pre-qualification tools increase our ability to measure the capabilities and safety performance of contract service providers, and thereby improve safety.



BRENT HARRISON,
TEAM LEAD, ENVIRONMENT,
HEALTH & SAFETY,
CANADIAN DIVISION, ENCANA

STRONG SAFETY RESULTS

Encana is diligent in ensuring the best safety practices are in place across its operations. In 2009, the company continued efforts to reinforce its safety culture and delivered the best safety results since its inception in 2002.

Encana recognizes that continuous improvement in safety performance requires effective collaboration with its many contractors. Encana has had a safety management contractor pre-qualification system called PEC/Premier Safety Management for several years in the USA Division. In 2009 the Canadian Division implemented a new system, ISNetworld, to keep pace with its advancing safety culture and increased focus on safety performance measurement. Staff worked closely with contract service providers to educate them on the need, benefits and processes to transition successfully to the new system.

“Across the company our various pre-qualification tools increase our ability to measure the capabilities and safety performance of contract service providers, and thereby improve safety,” says Brent Harrison, Team Lead, Environment, Health & Safety. “All contractors are required to achieve a satisfactory performance rating in order to continue working with us.”

PARTNERING TO IMPROVE SAFETY AND REDUCE EMISSIONS

In 2009, Encana piloted Real-Time Onboard Vehicle Evaluation Reporting (ROVER), a small device installed in vehicles to provide drivers with data to help improve driving safety performance and reverse motor vehicle incident rate trends by using technology to change behaviour.

Tests run on 50 company vehicles in Texas over the summer showed hard braking dropped by 20 percent and the percentage of drivers deemed aggressive – initially seven percent – was negligible at the end of the test.

Encana plans to install ROVER in all its U.S. vehicles as part of its efforts to increase driver safety and save lives. The program is now also being piloted in Canada.

Encana IN THE COMMUNITY

ENCANA'S COMMUNITY RELATIONS AND COMMUNITY INVESTMENT PROGRAMS GO HAND-IN-HAND AND ARE VITAL TO THE COMPANY'S OVERALL BUSINESS STRATEGY. ENCANA'S APPROACH TO BUILDING RELATIONSHIPS AND PARTNERING WITH COMMUNITIES IS RESPONSIVE AND PROACTIVE.

Encana strives to be a good neighbour by working to understand the needs of each community, actively seeking feedback and always looking for ways to improve performance.

Encana's Community Investment program is aligned with Imagine Canada's standard for corporate giving – a minimum of one percent of the company's domestic pre-tax profits to support the communities where it operates. Encana supports community initiatives in five key areas: community enhancement; environment; family and community wellness; science, trades and technology; and sport and recreation. Here are some examples of the difference Encana's programs have made in communities where it operates.

FIGHTING INVASIVE PLANTS IN EAST TEXAS

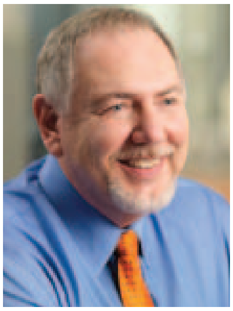
Many East Texas lakes are plagued by invasive water weeds blocking access of boaters and anglers, and either crowding or shading out native plants more beneficial to fish and wildlife. Now, thanks to a partnership with Encana, the Texas Parks and Wildlife Foundation has two new electric pumps to eradicate invasive plants.

An Encana donation will also fund a new program placing high school students in natural settings for service-oriented projects, as well as providing facilities for the Texas Game Warden Training Centre.

TRAINING VISIONARIES IN COLORADO

The University of Colorado in Denver benefited from an Encana donation to a capital campaign to renovate its downtown Business School building. The school's Global Energy Management (GEM) suite in the renovated building will be named for Encana to recognize the company's support and work to develop the GEM curricula.

GEM is a Master of Science level program to equip future leaders to develop creative solutions for energy-related issues. "It's geared to develop strong energy leaders for the future," says Don McClure, Vice-President, Government & Stakeholder Relations, USA Division, noting that several Encana employees are currently enrolled. Encana is part of the GEM advisory board that worked with the University of Colorado, Denver Business School to develop the curricula.



DON McCLURE,
VICE-PRESIDENT, GOVERNMENT & STAKEHOLDER RELATIONS,
USA DIVISION, ENCANA

BRINGING GAS SUPPLY TO TOMSLAKE, B.C.

In the heart of Peace Country, perched atop the large Montney natural gas play, it was wood and propane heating the homes and fuelling the stoves of Tomslake, British Columbia residents – not natural gas. That's until Encana partnered with Pacific Northern Gas (PNG) and the Peace River Regional District to find a solution.

Encana ranks 25th on the Global 100 list of sustainable companies

Encana was one of only five Canadian energy companies named to the fifth annual Global 100 list of the most sustainable large corporations in the world by Corporate Knights, a Canadian magazine that focuses on responsible business practices. The Global 100 companies from 24 countries were evaluated according to how effectively they manage environmental, social and governance risks and opportunities, relative to their industry peers.

"Some Tomslake residents had gas wells on their own property, but no access to natural gas for their homes or businesses," says Brian Lieverse, Community Relations Advisor. "We worked for two years with the District and PNG on an agreement to help bring natural gas to homes in the area."

Today, thanks to a partnership between Encana, the District and PNG, a 20-year deal benefits more than 400 remote Tomslake residential customers who have chosen to sign up for natural gas distribution.

BRIAN LIEVERSE,
COMMUNITY RELATIONS ADVISOR,
CANADIAN DIVISION, ENCANA

COURTESY MATTERS

Often, Encana's best practice approaches to partnering with communities inspire others. In 2009, the Province of British Columbia expressed an interest in Encana's Courtesy Matters program. The government mandated a good neighbours program for all oil and gas operators. The new program, developed by the Canadian Association of Petroleum Producers (CAPP), is based on Encana's Courtesy Matters initiative.

"Courteous, respectful behaviour is a way of doing business at all levels of our organization, from management in Calgary to our people working in the field," says Mike Forgo, Vice-President, Business Services & Stakeholder Relations, Canadian Division.

"Courtesy Matters is a collaborative approach to finding solutions and requires commitment every day from our employees, contractors and the community," says Forgo.

Encana's partnership on many community projects greatly contributes to the quality of life in Drumheller and surrounding areas.

BRYCE NIMMO, MAYOR OF DRUMHELLER,
ON ENCANA RECEIVING THE CORPORATE VOLUNTEER OF
EXCELLENCE AWARD FROM THE TOWN OF DRUMHELLER IN 2009

Courtesy Matters is formulated on the premise that being a good neighbour and making small behavioural changes can make a big difference in the communities where Encana operates. The program uses various tools to foster dialogue and address community concerns such as traffic, noise, dust, gates or garbage. In most areas of operation, a Courtesy Matters committee of landowners, community members and local government brings forward issues and seeks solutions to address them.

PARTNERING WHERE IT COUNTS

The concept of gathering ideas and solutions from the community, employees and other stakeholders is one of the constants of Encana's community programs. "Encana's goal is to be the operator of choice in all areas where we work," says Forgo. "It's a commitment we strive to uphold every day."

That commitment can make a world of difference to the long-term sustainability and health of those areas where Encana operates. One such example is Encana's contributions to stewarding precious water resources and wetland habitats.

In 2009, Encana continued to expand its water stewardship program, sharing knowledge with employees and communities to promote better understanding of the need for responsible resource development and sound water management. "We need to equip employees to be confident in their roles as ambassadors in the community and to know Encana is acting responsibly," says Mike Graham, Executive Vice-President & President, Canadian Division.

Encana's four-year partnership with Ducks Unlimited Canada (DUC) furthers work to conserve and/or restore wetland habitats. "Through numerous years of partnership, Encana continues to demonstrate its commitment to supporting environmental initiatives centred upon the conservation, restoration and sustainable land development in many wetland-rich landscapes of western Canada," says Rick Shewchuk, DUC Development Manager, Northern Alberta, Northwest Territories and Yukon.

Encana also supports Ducks Unlimited's Project Webfoot, a program aimed at teaching children about the importance of wetlands. In 2009, approximately 1,500 schoolchildren benefited from participating in Project Webfoot.

These are just a few examples demonstrating Encana's 2009 commitment to communities where it works. Other projects included:

- Encana's work with Project NEED (National Energy Education Development in the U.S.) to provide Kindergarten through Grade 12 teachers with tools to teach about energy
- Calgary Health Trust's Reach! campaign, supporting research in infectious diseases and diabetes at the University of Calgary

RESPONSIBLE DEVELOPMENT

Encana's commitment: People, Safety, Environment, Engagement, Community Investment

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natural gas

STEADFAST COMMITMENT TO RESPONSIBLE DEVELOPMENT

Encana is committed to responsible development. That commitment manifests itself in every aspect of the way we do business.

We see our commitment as encompassing five key areas: people, safety, environment, engagement and community investment.

Success depends on sound policies and leading practices. It all starts with our employees – the people who strive every day to do the right thing.

PEOPLE

RESPONSIBLE DEVELOPMENT STARTS WITH OUR PEOPLE

Attracting and retaining the best and brightest people to Encana is at the heart of our growth business strategy. We rely on their talent and ingenuity to help our business thrive so we can deliver on our promises to our employees, shareholders, communities and customers.

With that in mind, we have developed Human Resources programs and practices to provide support and development opportunities at every stage of an employee's career with us. We have a diverse workforce that spans new graduates through to very experienced contributors; all have the same access to continued learning and development.

Encana's innovative practices and programs help us attract and retain the best people for the job. Some examples are:

- Development programs for new graduates and developing professionals,
- Processes that support the movement of employees to work on new resource plays, be assigned to priority projects or to pursue developing a new field of expertise altogether;
- Industry competitive total compensation programs;
- A high performance contract and assessment process to help all employees focus on what they need to achieve;
- A North American approach to learning and employee development that includes opportunities to work in Canada and the US; and
- Creative workplace practices designed to support a work-life balance.

Encana encourages employees to develop new skills and experience. We support participation in external assignments and exchanges with industry organizations and government. We share our expertise and perspectives through employee representatives on industry associations. But most importantly, we provide a wealth of personal development opportunities that allow employees to continually grow and develop. Our dynamic business strategy lends itself to the expression that every day is an opportunity to learn at Encana.

SAFETY

SAFETY IS A CORE VALUE AT ENCANA AND ACHIEVING AN INJURY-FREE WORKPLACE IS OUR GOAL

We are uncompromising in our commitment to safety as a core value across our operations. We focus on keeping safety top-of-mind at work and at home every single day. We remind each other that it's not worth doing if we can't do it safely. And we're always looking for opportunities to improve.

Through a combination of safety practices and environment, health and safety management systems, we strive to identify hazards and eliminate or control risks. We prevent injuries on our worksites by:

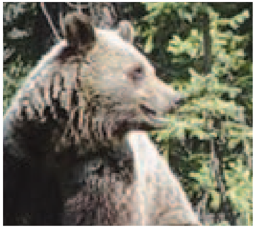
- ensuring all employees and contractors receive the training and experience they need to work safely
- working collaboratively with our service providers and contractors to create safer worksites
- investigating incidents and sharing what we've learned from them when they happen to prevent recurrence
- educating employees about the importance of safe driving on and off the job
- requiring an alcohol- and drug-free workplace
- communicating openly about safety successes and challenges

Full-scale emergency response exercises allow us to test our emergency response plans, establish working relationships with first responders, such as police and paramedics, and demonstrate to communities where we operate that we are well-prepared for emergencies.

RESPONSIBLE ENVIRONMENTAL MANAGEMENT – A RESPECTFUL AND HOLISTIC APPROACH

Like most of our stakeholders, we live and work in the communities where we have operations. We care about the impact of energy development on the environment.

Each area in which we work brings its own unique environmental challenges. That's why we have adopted a holistic approach, working closely with stakeholders to gather knowledge, to develop an environmental approach that is tailored to the unique physical characteristics of each operating area. Those environmental considerations are built into every project. We then use technology and innovation to lessen our environmental footprint.



Encana earned recognition from the Carbon Disclosure Project: Canada 200 in 2009 for being open and transparent in greenhouse gas reporting, earning a Top 10 ranking in the high carbon impact sectors category.

The Carbon Disclosure Project is a not-for-profit organization that holds the largest database of corporate climate change information in the world. They have become the gold standard for carbon disclosure methodology and process. Beyond reporting, Encana's commitment to measurable reductions in energy use and related emissions is evidenced by our investment in new research and technology aimed at lowering our carbon output.

Encana has more than 8,700 solar panels across its North American operations.

ENGAGEMENT

STAKEHOLDER TRUST AND INVOLVEMENT CRUCIAL TO OUR SUCCESS

Ensuring our stakeholders know who we are and what to expect from us is crucial to our success.

We are committed to working with stakeholders in an honest, transparent and respectful manner, listening to their concerns and working together to find solutions.

Open dialogue with stakeholders enables good decision making, helps identify and resolve issues, builds strong communities and supports shared learning before, during and after our operating activities.

Effective stakeholder engagement at Encana is about building trust, communication, and collaboration. Our approach is tailored to meet the individual needs of our stakeholders through a wide variety of communication methods.

Encana is committed to establishing mutually beneficial relationships with Aboriginal communities situated near our operations through honest dialogue and respectful engagement. Close liaison with the Aboriginal communities where we operate is essential to the long-term sustainability of our operations.

Who are our stakeholders?

Encana has many stakeholders including employees and contractors, landowners and their neighbours and communities, Aboriginal communities, governments and regulators, shareholders, financial institutions, private sector partners and competitors, and non-government and community organizations.

Our Integrity and Courtesy Matters Hotlines allow stakeholders to communicate directly with Encana if they have questions, issues or concerns with the way we work.

1-877-445-3222/integrity.hotline@encana.com
1-888-568-6322/courtesymatters@encana.com

INVESTING FOR SUSTAINABLE COMMUNITIES

Encana takes great pride in being a responsible corporate citizen.

Encana strives to be a good neighbour by working with communities to understand and support their needs. Encana's community investment program is aligned with our business strategy and provides for mutually beneficial relationships with community and non-government organizations.

Encana supports community initiatives in six key areas:

Environment **–** includes partnerships with organizations that care for and protect the environment as well as those that provide environmental education to youth

Science, trades and technology **–** provides support for development of a skilled and sustainable workforce through investments in educational programs

Family and community wellness **–** support for community organizations that promote wellness, contribute to the prevention of illness or injury, and enhance health care, social and emergency services

Sport and recreation **–** support for programs aimed at the physical and social well-being of communities

Community enhancement **–** support for cultural programs and economic development

Employee programs **–** we encourage and support employees' efforts to make a difference in their communities through a matching gifts program and an employee volunteer program that provide grants to organizations where employees volunteer their time

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www.encana.com/responsibility

encana™ natural gas

FINANCIAL HIGHLIGHTS (Pro Forma)

(US$ millions, except per share amounts)	2009	2008
Revenues, Net of Royalties	6,732	13,505
Cash Flow	5,021	6,354
Per Share – Diluted	6.68	8.45
Net Earnings	749	3,405
Per Share – Diluted	1.00	4.53
Operating Earnings	1,767	2,605
Per Share – Diluted	2.35	3.47
Total Capital Investment	3,755	5,255
Net Acquisition and Divestiture Activity	(815)	317
Net Capital Investment	2,940	5,572
Dividends Per Common Share *($/share)*	0.80	0.80
Dividend Yield *(%)* (2)	2	2
Debt to Capitalization *(%)*	32	n/a
Debt to Adjusted EBITDA *(times)* (1)	2.1	n/a
Debt (1) to Proved Developed Reserves *($/Mcfe)*	1.14	n/a

(1) Non-GAAP measures as referenced in the Advisory on page 73.

(2) Based on NYSE closing price at year end.

OPERATIONAL HIGHLIGHTS (Pro Forma)

After Royalties	2009	2008
Production		
Natural Gas *(MMcf/d)*		
Canada	1,224	1,300
USA	1,616	1,633
Total Natural Gas *(MMcf/d)*	2,840	2,933
Oil & NGLs *(bbls/d)*		
Canada	15,880	19,980
USA	11,317	13,350
Total Oil & NGLs *(bbls/d)*	27,197	33,330
Total Production *(MMcfe/d)*	3,003	3,132
Reserves (1)		
Year-End Reserves *(Bcfe)*	12,774	12,402
Net Reserve Additions *(Bcfe)*	1,857	1,848
Production Replacement *(%)*	169	161
Finding and Development Cost *($/Mcfe)*	1.62	2.18
Recycle Ratio	3.2	2.9
Reserve Life Index *(years)*	11.7	10.8

(1) 2009 before SEC price revisions

For additional information on reserves reporting protocols, see page 72.


The price of natural gas won't cost us the future.
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MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2009 (U.S. Dollars)

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, 2009, the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2008, the unaudited Pro Forma Consolidated Financial Information for the year ended December 31, 2009 presented in EnCana's Interim Supplemental Information, the unaudited Pro Forma Consolidated Financial Statements for the period ended September 30, 2009, as well as EnCana's Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. dated October 20, 2009.

The Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. oil and gas disclosures reporting. This document is dated February 17, 2010.

Readers should also read the Advisory section located at the end of this document, which provides information on Forward-Looking Statements, Oil and Gas Information and Currency, Pro Forma Information, Non-GAAP Measures and References to EnCana.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL STATEMENTS

ENCANA'S STRATEGIC OBJECTIVES

EnCana is one of North America's leading natural gas producers, focusing on the development of unconventional natural gas resources across North America. EnCana holds a diversified portfolio of prolific shale and other gas resource plays in key basins stretching from northeast British Columbia to Louisiana.

EnCana continues to focus on strong, sustainable production growth from unconventional natural gas plays in major North American basins. EnCana's Corporate Guidance is available on the Company's website at www.encana.com.

EnCana remains highly focused on key business objectives of maintaining financial strength, optimizing capital investments and continuing to pay a stable dividend to shareholders – attained through a disciplined approach to capital spending, a flexible investment program and financial stewardship. EnCana has been consistently among the lowest cost companies in the natural gas industry and has a history of entering resource plays early and leveraging technology to unlock unconventional resources.

EnCana has a strong balance sheet and continues to employ a conservative capital structure and market risk mitigation strategy. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times. At December 31, 2009, the Company's Debt to Capitalization ratio was 32 percent and consolidated Debt to Adjusted EBITDA was 1.3 times. In addition, the Company had approximately $4.3 billion in cash and short-term investments primarily as a result of a corporate reorganization more fully described in EnCana's Business section of this MD&A. As of January 31, 2010, EnCana has hedged approximately 2 billion cubic feet ("Bcf") per day ("Bcf/d") of expected 2010 gas production using NYMEX fixed price contracts at an average price of $6.04 per thousand cubic feet ("Mcf"). In addition, EnCana has hedged approximately 935 million cubic feet per day ("MMcf/d") of expected 2011 gas production at an average price of $6.52 per Mcf, and approximately 870 MMcf/d of expected 2012 gas production at an average price of $6.47 per Mcf. During 2009, EnCana benefited from its commodity price hedging program, which resulted in consolidated realized after-tax hedging gains of $2.9 billion.

ENCANA'S BUSINESS

On November 30, 2009, EnCana completed a corporate reorganization (the "Split Transaction") to split into two independent publicly traded energy companies – EnCana Corporation, a natural gas company, and Cenovus Energy Inc. ("Cenovus"), an integrated oil company.

The Split Transaction was initially proposed in May 2008 and was designed to enhance long-term value for shareholders by creating two independent and sustainable companies, each with the ability to pursue and achieve greater success by employing operational strategies best suited to its unique assets and business plan. In October 2008, due to an unusually high level of uncertainty and volatility in the global debt and equity markets, EnCana delayed seeking shareholder and court approval for the Split Transaction until there were clear signs that the global financial markets had stabilized. In September 2009, EnCana announced plans to proceed with the split.

Under the Split Transaction, EnCana shareholders received one new EnCana Common Share and one Cenovus Common Share for each EnCana Common Share previously held. As at December 31, 2009, EnCana had 751.3 million Common Shares outstanding (2008 – 750.4 million; 2007 – 750.2 million).

EnCana's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Financial information is presented on an after eliminations basis.

EnCana's operations are currently divided into two operating divisions:

- **Canadian Division,** formerly the Canadian Foothills Division, which includes natural gas development and production assets located in British Columbia and Alberta, and the Deep Panuke natural gas project offshore Nova Scotia. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia, including the Horn River shale play; (ii) Cutbank Ridge on the Alberta and British Columbia border, including the Montney formation; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in southern Alberta.
- **USA Division,** which includes the natural gas development and production assets located in the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) East Texas in Texas; and (iv) Fort Worth in Texas. The USA Division is also focused on the development of the Haynesville shale play located in Louisiana and Texas and the recent entrance into the Marcellus shale play located in Pennsylvania.

In conjunction with the Split Transaction, the upstream assets formerly included in EnCana's Canadian Plains Division and Integrated Oil Division were transferred to Cenovus. As a result, EnCana has updated its reporting, and the Canadian Plains and Integrated Oil – Canada are now presented as **Canada – Other**. Canada – Other results are reported as continuing operations. The U.S. Downstream Refining assets were also transferred to Cenovus. U.S. Downstream Refining results prior to the November 30, 2009 Split Transaction are reported in Discontinued Operations. Prior periods have been restated to reflect the new presentation.

Pro Forma and Consolidated Reporting

This MD&A presents the financial and operating results of EnCana on both a pro forma and consolidated basis.

EnCana's pro forma results exclude the results of operations from assets transferred to Cenovus as part of the Split Transaction and reflect expected changes to EnCana's historical results that would arise from the Split Transaction, including income tax, depreciation, depletion and amortization ("DD&A") and transaction costs. This information is presented to assist in understanding EnCana's historical financial results associated with the assets remaining in EnCana as a result of the Split Transaction.

EnCana's 2009 consolidated results include 12 months of EnCana operations and 11 months of Cenovus operations. Consolidated results for 2008 and 2007 include 12 months of EnCana and Cenovus operations.

Non-GAAP Measures

This MD&A contains certain non-GAAP measures commonly used in the oil and gas industry and by EnCana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Further information can be found in the Reconciliations of Non-GAAP Measures section of this MD&A.

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and net change in non-cash working capital from Discontinued Operations. Cash Flow is commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. Operating Earnings is commonly used in the oil and gas industry and by EnCana to provide investors with information that is more comparable between periods.

2009 PRO FORMA OVERVIEW

In 2009, EnCana reported pro forma:

- Cash Flow of $5,021 million;
- Operating Earnings of $1,767 million;
- Net Earnings of $749 million;
- Total production of 3,003 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d");
- Realized financial natural gas, crude oil and other commodity hedging gains of $2,250 million after-tax;
- Capital investment of $3,755 million; and
- Average natural gas prices, excluding financial hedges, of $3.73 per Mcf and average liquids prices, excluding financial hedges, of $48.15 per barrel ("bbl").

2009 CONSOLIDATED OVERVIEW

In 2009, EnCana reported:

- Completion of its plan to split into two independent publicly traded energy companies on November 30, 2009;
- Cash Flow of $6,779 million;
- Operating Earnings of $3,495 million;
- Net Earnings of $1,862 million;
- Total production of 4,365 MMcfe/d;
- Realized financial natural gas, crude oil and other commodity hedging gains of $2,935 million after-tax;
- Capital investment of $5,454 million; and
- Average natural gas prices, excluding financial hedges, of $3.69 per Mcf and average liquids prices, excluding financial hedges, of $49.65 per bbl.

BUSINESS ENVIRONMENT

EnCana's financial results were significantly influenced by fluctuations in commodity prices, which included price differentials, and the U.S./Canadian dollar exchange rate. EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found in the Risk Management section of this MD&A and Note 20 to the Consolidated Financial Statements. The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana's financial results.

Quarterly Market Benchmark Prices and Foreign Exchange Rates

(Average for the period)	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1	2007
Natural Gas Price Benchmarks											
AECO *(C$/Mcf)*	$ 4.14	$ 4.23	$ 3.02	$ 3.66	$ 5.63	$ 8.13	$ 6.79	$ 9.24	$ 9.35	$ 7.13	$ 6.61
NYMEX *($/MMBtu)*	3.99	4.17	3.39	3.50	4.89	9.04	6.94	10.24	10.93	8.03	6.86
Rockies (Opal) *($/MMBtu)*	3.09	3.97	2.69	2.37	3.31	6.25	3.53	5.88	8.56	7.02	3.95
Texas (HSC) *($/MMBtu)*	3.78	4.16	3.31	3.44	4.21	8.67	6.37	9.98	10.58	7.73	6.58
Basis Differential *($/MMBtu)*											
AECO/NYMEX	0.40	0.19	0.67	0.39	0.35	1.23	1.10	1.28	1.71	0.84	0.75
Rockies/NYMEX	0.90	0.20	0.70	1.13	1.58	2.79	3.41	4.36	2.37	1.01	2.91
Texas/NYMEX	0.21	0.01	0.08	0.06	0.68	0.37	0.58	0.26	0.35	0.30	0.28
Crude Oil Price Benchmarks											
West Texas Intermediate (WTI) *($/bbl)*	62.09	76.13	68.24	59.79	43.31	99.75	59.08	118.22	123.80	97.82	72.41
Western Canadian Select (WCS) *($/bbl)*	52.43	64.01	58.06	52.37	34.38	79.70	39.95	100.22	102.18	76.37	49.50
Differential – WTI/WCS *($/bbl)*	9.66	12.12	10.18	7.42	8.93	20.05	19.13	18.00	21.62	21.45	22.91
Foreign Exchange											
U.S./Canadian Dollar Exchange Rate	0.876	0.947	0.911	0.857	0.803	0.938	0.825	0.961	0.990	0.996	0.930

PRO FORMA FINANCIAL RESULTS

The following table presents selected historical pro forma financial information related to EnCana's ongoing operations only and should be read with the unaudited Pro Forma Consolidated Financial Information for the year ended December 31, 2009 presented in EnCana's Interim Supplemental Information, the unaudited Pro Forma Consolidated Financial Statements for the period ended September 30, 2009, as well as the unaudited Pro Forma Consolidated Financial Statements for the period ended June 30, 2009 and year ended December 31, 2008 presented in EnCana's Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. dated October 20, 2009. The information excludes the results of operations from assets transferred to Cenovus as part of the Split Transaction and reflects expected changes to EnCana's historical results that would arise from the Split Transaction, including income tax, DD&A and transaction costs. This information is presented to assist in understanding EnCana's historical financial results associated with the assets remaining in EnCana as a result of the Split Transaction.

($ millions, except per share amounts)	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1
Pro Forma Cash Flow (1)	$ 5,021	$ 930	$ 1,274	$ 1,430	$ 1,387	$ 6,354	$ 1,502	$ 1,734	$ 1,661	$ 1,457
per share – diluted	6.68	1.24	1.70	1.90	1.85	8.45	2.00	2.31	2.21	1.93
Pro Forma Operating Earnings (2)	1,767	373	378	472	544	2,605	546	805	703	551
per share – diluted	2.35	0.50	0.50	0.63	0.72	3.47	0.73	1.07	0.94	0.73
Pro Forma Net Earnings	749	233	(53)	92	477	3,405	671	2,228	643	(137)
per share – diluted	1.00	0.31	(0.07)	0.12	0.63	4.53	0.89	2.97	0.86	(0.18)

(1) Pro Forma Cash Flow is a non-GAAP measure. See Reconciliations of Non-GAAP Measures section of this MD&A.

(2) Pro Forma Operating Earnings is a non-GAAP measure. See Reconciliations of Non-GAAP Measures section of this MD&A.

Pro Forma Cash Flow

2009 versus 2008

Pro Forma Cash Flow of $5,021 million decreased $1,333 million as a result of:

- Average total natural gas prices, excluding financial hedges, decreased to $3.73 per Mcf in 2009 compared to $7.99 per Mcf in 2008;
- Average total liquids prices, excluding financial hedges, decreased to $48.15 per bbl in 2009 compared to $84.38 per bbl in 2008; and
- Natural gas production volumes in 2009 decreased to 2,840 MMcf/d from 2,933 MMcf/d in 2008. The decrease was primarily a result of shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment, partially offset by lower royalties;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $2,250 million after-tax in 2009 compared to losses of $6 million after-tax in 2008; and
- Lower production and mineral taxes, operating expenses and transportation and selling costs primarily due to the lower U.S./Canadian dollar exchange rate and cost savings measures.

EnCana reported 2009 Pro Forma Cash Flow of $5,021 million compared to $4,200 million in its Corporate Guidance dated November 12, 2009. Actual pro forma results were higher than Corporate Guidance primarily due to the inclusion, in Corporate Guidance, of current tax related to the wind-up of the Canadian oil and gas partnership and transaction costs related to the Split Transaction as disclosed in the document.

Q4 2009 versus Q4 2008

Pro Forma Cash Flow of $930 million decreased $572 million as a result of:

- Average total natural gas prices, excluding financial hedges, decreased to $4.47 per Mcf in 2009 compared to $5.39 per Mcf in 2008; and
- Natural gas production volumes in 2009 decreased to 2,687 MMcf/d from 2,979 MMcf/d in 2008. The decrease was primarily a result of shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment, partially offset by lower royalties.

Pro Forma Operating Earnings

Summary of Pro Forma Operating Earnings

($ millions, except per share amounts)	2009	Per share (1)	2008	Per share (1)
Pro Forma Net Earnings, as reported	$ 749	$ 1.00	$ 3,405	$ 4.53
Add back (losses) and deduct gains:				
Unrealized mark-to-market accounting gain (loss), after-tax	(1,352)	(1.80)	1,299	1.73
Non-operating foreign exchange gain (loss), after-tax	334	0.45	(598)	(0.80)
Gain (loss) on discontinuance, after-tax	–	–	99	0.13
Pro Forma Operating Earnings	$ 1,767	$ 2.35	$ 2,605	$ 3.47

(1) Per Common Share – diluted.

2009 versus 2008

Pro Forma Operating Earnings of $1,767 million decreased $838 million. In addition to the items affecting Pro Forma Cash Flow described previously, a significant item affecting Pro Forma Operating Earnings was:

- Lower DD&A of $326 million primarily due to lower production volumes and the lower U.S./Canadian dollar exchange rate.

Pro Forma Net Earnings

2009 versus 2008

Pro Forma Net Earnings of $749 million decreased $2,656 million. Significant items affecting Pro Forma Net Earnings were:

- Lower average total natural gas and total liquids prices, excluding financial hedges, as well as lower natural gas production volumes as discussed in the Pro Forma Cash Flow section of this MD&A; and
- The net impact of realized and unrealized hedging, after-tax, which resulted in an $898 million increase to Pro Forma Net Earnings in 2009 compared to a $1,293 million increase to Pro Forma Net Earnings in 2008;

partially offset by:

- Non-operating foreign exchange gains of $334 million after-tax in 2009 compared to losses of $598 million after-tax in 2008;
- Lower costs of operations as discussed in the Pro Forma Cash Flow section of this MD&A; and
- Lower DD&A of $326 million primarily due to lower production volumes and the lower U.S./Canadian dollar exchange rate.

Q4 2009 versus Q4 2008

Pro Forma Net Earnings of $233 million decreased $438 million. Significant items affecting Pro Forma Net Earnings were:

- Lower average total natural gas prices, excluding financial hedges, as well as lower natural gas production volumes as discussed in the Pro Forma Cash Flow section of this MD&A; and
- The net impact of realized and unrealized hedging, after-tax, which resulted in a $193 million increase to Pro Forma Net Earnings in 2009 compared to an $818 million increase to Pro Forma Net Earnings in 2008;

partially offset by:

- Non-operating foreign exchange losses of $5 million after-tax in 2009 compared to losses of $350 million after-tax in 2008.

Summary of Hedging Impacts on Pro Forma Net Earnings

($ millions)	2009	2008	Q4 2009	Q4 2008
Unrealized Mark-to-Market Gains (Losses), after-tax (1)	$ (1,352)	$ 1,299	$ (135)	$ 475
Realized Hedging Gains (Losses), after-tax (2)	2,250	(6)	328	343
Hedging Impacts on Net Earnings	$ 898	$ 1,293	$ 193	$ 818

(1) Included in Corporate and Other financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate and Other section of this MD&A.

(2) Included in Divisional financial results.

CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1	2007
Cash Flow [(1)]	$ 6,779	$ 603	$ 2,079	$ 2,153	$ 1,944	$ 9,386	$ 1,299	$ 2,809	$ 2,889	$ 2,389	$ 8,453
per share – diluted	9.02	0.80	2.77	2.87	2.59	12.48	1.73	3.74	3.85	3.17	11.06
Operating Earnings [(2)]	3,495	855	775	917	948	4,405	449	1,442	1,469	1,045	4,100
per share – diluted	4.65	1.14	1.03	1.22	1.26	5.86	0.60	1.92	1.96	1.39	5.36
Net Earnings	1,862	636	25	239	962	5,944	1,077	3,553	1,221	93	3,959
per share – diluted	2.48	0.85	0.03	0.32	1.28	7.91	1.43	4.73	1.63	0.12	5.18

(1) Cash Flow is a non-GAAP measure. See Reconciliations of Non-GAAP Measures section of this MD&A.

(2) Operating Earnings is a non-GAAP measure. See Reconciliations of Non-GAAP Measures section of this MD&A.

Consolidated Cash Flow

2009 versus 2008

Cash Flow of $6,779 million decreased $2,607 million as a result of:

- Average total natural gas prices, excluding financial hedges, decreased to $3.69 per Mcf in 2009 compared to $7.94 per Mcf in 2008;
- Average total liquids prices, excluding financial hedges, decreased to $49.65 per bbl in 2009 compared to $76.58 per bbl in 2008; and
- Natural gas production volumes in 2009 decreased to 3,602 MMcf/d from 3,838 MMcf/d in 2008. The decrease was primarily a result of shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment and one month less of volumes associated with Cenovus operations;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $2,935 million after-tax in 2009 compared to losses of $219 million after-tax in 2008;
- Lower transportation and selling costs, operating expenses and production and mineral taxes primarily due to one month less of costs associated with Cenovus operations, the lower U.S./Canadian dollar exchange rate and cost savings measures;
- Cash Flow from Discontinued Operations of $149 million in 2009 compared to negative Cash Flow of $441 million in 2008; and
- A decrease in current tax, excluding the tax related to realized financial hedges mentioned above, as a result of lower cash flows, partially offset by the incremental current tax expense related to the wind-up of the Canadian oil and gas partnership.

2008 versus 2007

Cash Flow of $9,386 million increased $933 million as a result of:

- Average total natural gas prices, excluding financial hedges, increased to $7.94 per Mcf in 2008 compared to $5.89 per Mcf in 2007;
- Average total liquids prices, excluding financial hedges, increased to $76.58 per bbl in 2008 compared to $50.05 per bbl in 2007;
- Natural gas production volumes in 2008 increased to 3,838 MMcf/d from 3,566 MMcf/d in 2007; and
- A decrease in current tax associated with accelerated write-offs for certain U.S. capital expenditures and increased benefits from international financing, partially offset by a one time tax recovery in 2007 for a Canadian tax legislative change;

partially offset by:

- Negative Cash Flow from Discontinued Operations of $441 million in 2008 compared to Cash Flow of $678 million in 2007;
- Realized financial natural gas, crude oil and other commodity hedging losses of $219 million after-tax in 2008 compared to gains of $1,023 million after-tax in 2007; and
- Higher transportation and selling costs, operating expenses, production and mineral taxes, interest and administrative expenses.

Q4 2009 versus Q4 2008

Cash Flow of $603 million decreased $696 million as a result of:

- Higher current tax primarily related to the wind-up of the Canadian oil and gas partnership;
- Natural gas production volumes in 2009 decreased to 3,204 MMcf/d from 3,858 MMcf/d in 2008. The decrease was primarily a result of one month less of volumes associated with Cenovus operations as well as shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment; and
- Average total natural gas prices, excluding financial hedges, decreased to $4.34 per Mcf in 2009 compared to $5.44 per Mcf in 2008;

partially offset by:

- Negative Cash Flow from Discontinued Operations of $13 million in 2009 compared to $593 million in 2008; and
- Average total liquids prices, excluding financial hedges, increased to $62.25 per bbl in 2009 compared to $33.81 per bbl in 2008.

Consolidated Operating Earnings

Summary of Operating Earnings

($ millions, except per share amounts)	2009	Per share (1)	2008	Per share (1)	2007	Per share (1)
Net Earnings, as reported	$ 1,862	$ 2.48	$ 5,944	$ 7.91	$ 3,959	$ 5.18
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax	(1,792)	(2.38)	1,818	2.42	(811)	(1.06)
Non-operating foreign exchange gain (loss), after-tax	159	0.21	(378)	(0.50)	217	0.28
Gain (loss) on discontinuance, after-tax	–	–	99	0.13	152	0.20
Future tax recovery due to tax rate reductions	–	–	–	–	301	0.40
Operating Earnings	$ 3,495	$ 4.65	$ 4,405	$ 5.86	$ 4,100	$ 5.36

(1) Per Common Share – diluted.

2009 versus 2008

Operating Earnings of $3,495 million decreased $910 million. In addition to the items affecting Cash Flow described previously, significant items affecting Operating Earnings were:

- Lower DD&A of $331 million primarily due to lower production volumes and the lower U.S./Canadian dollar exchange rate; and
- Lower future income tax related to the wind-up of the Canadian oil and gas partnership and other items associated with the Split Transaction.

Consolidated Net Earnings

($ millions, except per share amounts)	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1	2007
Continuing Operations											
Net Earnings from Continuing Operations	$ 1,830	$ 589	$ 39	$ 211	$ 991	$ 6,499	$ 1,469	$ 3,833	$ 1,088	$ 109	$ 3,447
per share – basic	2.44	0.78	0.05	0.28	1.32	8.66	1.96	5.11	1.45	0.15	4.55
per share – diluted	2.44	0.78	0.05	0.28	1.32	8.64	1.96	5.10	1.45	0.14	4.51
Total Consolidated											
Net Earnings	1,862	636	25	239	962	5,944	1,077	3,553	1,221	93	3,959
per share – basic	2.48	0.85	0.03	0.32	1.28	7.92	1.44	4.74	1.63	0.12	5.23
per share – diluted	2.48	0.85	0.03	0.32	1.28	7.91	1.43	4.73	1.63	0.12	5.18
Total Assets	33,827					47,247					46,974
Total Long-Term Debt	7,768					9,005					9,543
Revenues, Net of Royalties	11,114	2,712	2,271	2,449	3,682	21,053	4,862	8,150	4,653	3,388	14,385

Net Earnings from Continuing Operations includes results for Canada – Other upstream assets transferred to Cenovus under the November 30, 2009 Split Transaction. Total Consolidated Net Earnings includes results for Downstream Refining assets transferred to Cenovus under the Split Transaction, which are classified as Discontinued Operations.

2009 versus 2008

Net Earnings of $1,862 million decreased $4,082 million. Significant items affecting Net Earnings were:

- Lower average total natural gas and total liquids prices, excluding financial hedges, as well as lower natural gas production volumes as discussed in the Cash Flow section of this MD&A; and
- The net impact of realized and unrealized hedging, after-tax, which resulted in a $1,143 million increase to Net Earnings in 2009 compared to a $1,599 million increase to Net Earnings in 2008;

partially offset by:

- Excluding the tax impacts associated with hedging and non-operating foreign exchange, future income tax expense decreased primarily due to the wind-up of the Canadian oil and gas partnership and other items associated with the Split Transaction;
- Lower costs of operations as discussed in the Cash Flow section of this MD&A;
- Net Earnings from Discontinued Operations of $32 million in 2009 compared to Net Loss of $555 million in 2008; and
- Non-operating foreign exchange gains of $159 million after-tax in 2009 compared to losses of $378 million after-tax in 2008.

2008 versus 2007

Net Earnings of $5,944 million increased $1,985 million. Significant items affecting Net Earnings were:

- Higher average total natural gas and total liquids prices, excluding financial hedges, as well as higher natural gas production volumes as discussed in the Cash Flow section of this MD&A; and
- The net impact of realized and unrealized hedging, after-tax, which resulted in a $1,599 million increase to Net Earnings in 2008 compared to a $212 million increase to Net Earnings in 2007;

partially offset by:

- Net Loss from Discontinued Operations of $555 million in 2008 compared to Net Earnings of $512 million in 2007;
- Higher costs of operations as discussed in the Cash Flow section of this MD&A;
- Non-operating foreign exchange losses of $378 million after-tax in 2008 compared to gains of $217 million after-tax in 2007;
- Higher DD&A of $378 million primarily due to the increase in production volumes; and
- Higher future income tax, excluding tax associated with realized hedging and non-operating foreign exchange, as a result of accelerated write-offs for certain U.S. capital expenditures and the effect of the reduction in Canadian federal corporate tax rates reflected in 2007.

Q4 2009 versus Q4 2008

Net Earnings of $636 million decreased $441 million. Significant items affecting Net Earnings were:

- The net impact of realized and unrealized hedging, after-tax, which resulted in a $223 million increase to Net Earnings in 2009 compared to a $1,186 million increase to Net Earnings in 2008; and
- Lower natural gas production volumes and lower average total natural gas prices, excluding financial hedges, as discussed in the Cash Flow section of this MD&A;

partially offset by:

- Excluding the tax impacts associated with hedging and non-operating foreign exchange, future income tax expense decreased primarily due to the wind-up of the Canadian oil and gas partnership and other items associated with the Split Transaction;
- Higher average total liquids prices, excluding financial hedges, as discussed in the Cash Flow section of this MD&A; and
- Non-operating foreign exchange losses of $19 million after-tax in 2009 compared to losses of $119 million after-tax in 2008.

Summary of Hedging Impacts on Net Earnings

($ millions)	2009	2008	2007	Q4 2009	Q4 2008
Unrealized Mark-to-Market Gains (Losses), after-tax (1)	$ (1,792)	$ 1,818	$ (811)	$ (200)	$ 747
Realized Hedging Gains (Losses), after-tax (2)	2,935	(219)	1,023	423	439
Hedging Impacts on Net Earnings	$ 1,143	$ 1,599	$ 212	$ 223	$ 1,186

(1) Included in Corporate and Other financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate and Other section of this MD&A.

(2) Included in Divisional financial results.

Net Capital Investment

	Pro Forma		Consolidated		
($ millions)	2009	2008	2009	2008	2007
Canadian Division	$ 1,869	$ 2,459	$ 1,869	$ 2,459	$ 2,403
USA Division	1,821	2,682	1,821	2,682	1,935
Market Optimization	–	1	2	17	6
Corporate & Other	65	113	85	165	154
Canada – Other (1)	–	–	848	1,500	1,238
Discontinued Operations (2)	–	–	829	478	220
Capital Investment	3,755	5,255	5,454	7,301	5,956
Acquisitions	260	1,174	260	1,174	2,688
Divestitures	(1,075)	(857)	(1,161)	(857)	(481)
Canada – Other (1)					
Net Acquisitions and Divestitures	–	–	(14)	(47)	14
Net Capital Investment	$ 2,940	$ 5,572	$ 4,539	$ 7,571	$ 8,177

(1) Canada – Other represents operations formerly included in Canadian Plains and Integrated Oil – Canada upstream assets that were transferred to Cenovus as a result of the November 30, 2009 Split Transaction.

(2) The former Integrated Oil Division U.S. Downstream Refining operations are included in Discontinued Operations.

EnCana's capital investment for 2009, 2008 and 2007 was funded by Cash Flow.

Pro forma capital investment during 2009 was primarily focused on continued development of EnCana's North American key resource plays. Pro forma capital investment of $3,755 million was lower due to reduced upstream activity levels as well as the change in the average U.S./Canadian dollar exchange rate, which decreased capital investment by $131 million in 2009 compared to 2008. Further information regarding the Company's capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

In 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $1,000 million (2008 – $400 million) in the Canadian Division, $73 million (2008 – $251 million) in the USA Division and $17 million in Canada – Other (2008 – $47 million).

On November 3, 2009, the Company completed the sale of Senlac Oil Ltd. for cash consideration of $83 million. The operations are included in Canada – Other. In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million, before closing adjustments, resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

Acquisitions in 2008 included land purchases of approximately $1,010 million in the Haynesville shale play in Louisiana. Acquisitions in 2007 included the purchase of Deep Bossier natural gas assets and land interests in East Texas for approximately $2.55 billion.

The Company also had some other minor property acquisitions and divestitures in 2009, 2008 and 2007.

Free Cash Flow

($ millions)	Pro Forma 2009	Pro Forma 2008	Consolidated 2009	Consolidated 2008	Consolidated 2007
Cash Flow [1]	$ 5,021	$ 6,354	$ 6,779	$ 9,386	$ 8,453
Capital Investment	3,755	5,255	5,454	7,301	5,956
Free Cash Flow [2]	$ 1,266	$ 1,099	$ 1,325	$ 2,085	$ 2,497

(1) Cash Flow is a non-GAAP measure and is defined under the Reconciliations of Non-GAAP Measures section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing activities, dividends and/or other financing activities.

EnCana's 2009 Pro Forma Free Cash Flow of $1,266 million was higher compared to 2008. Reasons for the variances in Pro Forma Cash Flow and Pro Forma Capital Investment are discussed under the Pro Forma Cash Flow and Net Capital Investment sections of this MD&A.

RESERVES AND PRODUCTION

Proved Oil and Gas Reserves

Since inception, EnCana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of the Company's natural gas and liquids reserves annually. The Company has a Reserves Committee of independent Board of Directors members, which reviews the qualifications and appointment of the IQREs. The Committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the IQREs. EnCana's disclosure of reserves data is covered by National Instrument 51-101 of the Canadian Securities Administrators as amended by a Decision dated September 29, 2008 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 U.S. Financial Accounting Standards Board reserves reporting requirements.

As of December 31, 2009, the SEC requires that estimates of oil and gas reserves be determined using an average price based upon the prior 12-month period rather than single day year-end prices.

Proved Reserves by Country

	Natural Gas (billions of cubic feet)			Liquids [1] (millions of barrels)		
(Constant Prices After Royalties, as at December 31)	2009	2008	2007	2009	2008	2007
Canada [2]	5,349	7,847	7,292	35.5	954.0	868.9
United States	5,713	5,831	6,008	41.2	51.6	58.3
Total	11,062	13,678	13,300	76.7	1,005.6	927.2

(1) Liquids include crude oil, NGLs and condensate.

(2) EnCana's reserves in Canada prior to November 30, 2009 include Canada – Other reserves (former Canadian Plains and Integrated Oil – Canada reserves) that were transferred to Cenovus as part of the Split Transaction.

Proved Reserves Reconciliation by Country

(Constant Prices After Royalties, year ended December 31, 2009)	Natural Gas (billions of cubic feet) Canada (3)	United States	Total	Liquids (1) (millions of barrels) Canada (3)	United States	Total	Total (2) (billions of cubic feet equivalent)
Beginning of year	7,847	5,831	13,678	954.0	51.6	1,005.6	19,712
Revisions and improved recovery	(755)	(845)	(1,600)	(80.3)	(12.6)	(92.9)	(2,157)
Extensions and discoveries	726	1,406	2,132	171.9	6.5	178.4	3,202
Acquisitions	28	–	28	0.5	–	0.5	31
Sale of reserves in place (4)	(1,772)	(89)	(1,861)	(968.3)	(0.2)	(968.5)	(7,672)
Production	(725)	(590)	(1,315)	(42.3)	(4.1)	(46.4)	(1,593)
End of year	**5,349**	**5,713**	**11,062**	**35.5**	**41.2**	**76.7**	**11,523**

(1) Liquids include crude oil, NGLs and condensate.

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

(3) EnCana's reserves in Canada prior to November 30, 2009 include Canada – Other reserves (former Canadian Plains and Integrated Oil – Canada reserves) that were transferred to Cenovus as part of the Split Transaction.

(4) Sale of reserves in place include the transfer of EnCana's Canadian Plains Division and Integrated Oil Division upstream assets to Cenovus as a result of the November 30, 2009 Split Transaction.

EnCana's natural gas reserves decreased by approximately 19 percent in 2009, largely as a result of low 12-month average prices and the Split Transaction. Approximately 75 percent of the negative revisions were a direct result of low 12-month average prices and approximately 80 percent of the sale of reserves in place was associated with the Split Transaction. Extensions and discoveries were 2,132 Bcf, of which approximately two-thirds were in the U.S. with the remaining balance in Canada.

In 2009, EnCana's crude oil and NGLs reserves decreased by approximately 77 percent and EnCana's bitumen reserves were divested, substantially all as a result of the Split Transaction.

Canadian Division and USA Division Proved Reserves

(As at December 31, 2009)	Natural Gas (billions of cubic feet) 2009	2008	2007	Liquids (1) (millions of barrels) 2009	2008	2007
Canadian Division (2)	**5,349**	5,992	5,273	**35.5**	45.0	41.8
USA Division	**5,713**	5,831	6,008	**41.2**	51.6	58.3
Total	**11,062**	11,823	11,281	**76.7**	96.6	100.1

(1) Liquids include crude oil, NGLs and condensate.

(2) 2008 and 2007 reserves exclude Canada – Other.

Canadian Division and USA Division Proved Reserves Reconciliation

(Year ended December 31, 2009)	Natural Gas (billions of cubic feet) Canadian Division (3)	USA Division	Total	Liquids (1) (millions of barrels) Canadian Division (3)	USA Division	Total	Total (2) (billions of cubic feet equivalent)
Beginning of year	5,992	5,831	11,823	45.0	51.6	96.6	12,402
Technical revisions	(305)	(98)	(403)	0.2	(8.9)	(8.7)	(455)
Extensions and discoveries	676	1,557	2,233	6.5	6.7	13.2	2,312
Acquisitions	31	–	31	0.5	–	0.5	34
Sale of reserves in place	(272)	(95)	(367)	(9.2)	(0.2)	(9.4)	(423)
Production	(447)	(590)	(1,037)	(5.8)	(4.1)	(9.9)	(1,096)
End of year	5,675	6,605	12,280	37.2	45.1	82.3	12,774
Price revisions (SEC) (4)	(326)	(892)	(1,218)	(1.7)	(3.9)	(5.6)	(1,251)
End of year (SEC)	**5,349**	**5,713**	**11,062**	**35.5**	**41.2**	**76.7**	**11,523**

(1) Liquids include crude oil, NGLs and condensate.

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

(3) Excludes Canada – Other.

(4) The impact of significantly lower prices for U.S. SEC reporting purposes (NYMEX – Henry Hub price of $3.87 per MMBtu in 2009 versus $5.71 per MMBtu in 2008) is reflected in the SEC price revisions.

Excluding price revisions for SEC reporting purposes, approximately 169 percent of production associated with EnCana's pro forma operations was replaced by reserves additions before acquisitions and divestitures during 2009. On this basis, natural gas equivalent reserves associated with EnCana's pro forma operations increased approximately 3 percent.

Production Volumes

	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1	2007
Produced Gas *(MMcf/d)*											
Canadian Division	**1,224**	**1,071**	**1,201**	**1,343**	**1,281**	1,300	1,302	1,351	1,289	1,256	1,255
USA Division	**1,616**	**1,616**	**1,524**	**1,581**	**1,746**	1,633	1,677	1,674	1,629	1,552	1,345
	2,840	**2,687**	**2,725**	**2,924**	**3,027**	2,933	2,979	3,025	2,918	2,808	2,600
Liquids *(bbls/d)*											
Canadian Division	**15,880**	**12,477**	**15,909**	**17,624**	**17,567**	19,980	19,702	19,947	20,155	20,123	18,272
USA Division	**11,317**	**11,586**	**10,325**	**11,699**	**11,671**	13,350	12,831	13,853	13,482	13,232	14,180
	27,197	**24,063**	**26,234**	**29,323**	**29,238**	33,330	32,533	33,800	33,637	33,355	32,452
Pro Forma Volumes *(MMcfe/d)* (1)	**3,003**	**2,831**	**2,883**	**3,100**	**3,203**	3,132	3,174	3,227	3,120	3,008	2,795
Canada – Other *(MMcfe/d)* (1)(2)	**1,362**	**970**	**1,504**	**1,502**	**1,472**	1,507	1,499	1,491	1,487	1,549	1,576
Total Volumes *(MMcfe/d)* (1)	**4,365**	**3,801**	**4,387**	**4,602**	**4,675**	4,639	4,673	4,718	4,607	4,557	4,371

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

(2) Canada – Other represents operations formerly included in Canadian Plains and Integrated Oil – Canada that were transferred to Cenovus as a result of the November 30, 2009 Split Transaction.

Total production volumes decreased 6 percent or 274 MMcfe/d in 2009 compared to 2008 and decreased 4 percent or 129 MMcfe/d on a pro forma basis. Lower pro forma volumes were primarily due to shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment, and natural declines in conventional properties. Total production volumes for Canada – Other includes all results prior to November 30, 2009 of the oil and gas assets transferred to Cenovus under the Split Transaction. Accordingly, total production volumes for 2009 include 12 months of EnCana operations and 11 months of Cenovus operations.

Total production volumes increased 6 percent or 268 MMcfe/d in 2008 compared to 2007 primarily due to increased production from EnCana's pro forma natural gas key resource plays of 21 percent, partially offset by natural declines in conventional properties and the volume impact of minor property divestitures.

DIVISIONAL RESULTS

As discussed in EnCana's Business section of this MD&A, the Company completed the Split Transaction on November 30, 2009. EnCana's divisions, after the Split Transaction, include the Canadian Division (formerly Canadian Foothills) and the USA Division.

Canadian Division

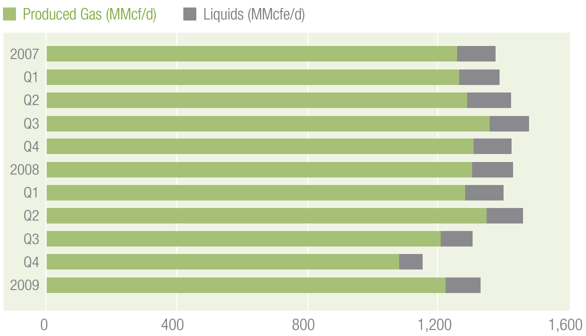
Financial Results

	2009				2008				2007			
($ millions)	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total
Revenues, Net of Royalties and Hedging	**$ 1,641**	**$ 277**	**$ 44**	**$ 1,962**	$ 3,862	$ 622	$ 57	$ 4,541	$ 2,885	$ 413	$ 57	$ 3,355
Realized Financial Hedging Gain (Loss)	**1,400**	**–**	**–**	**1,400**	(142)	(44)	–	(186)	347	(23)	–	324
Expenses												
Production and mineral taxes	**11**	**3**	**–**	**14**	28	5	–	33	36	3	–	39
Transportation and selling	**148**	**6**	**–**	**154**	201	12	26	239	192	9	–	201
Operating	**501**	**21**	**14**	**536**	549	39	21	609	482	33	20	535
Operating Cash Flow	**$ 2,381**	**$ 247**	**$ 30**	**$ 2,658**	$ 2,942	$ 522	$ 10	$ 3,474	$ 2,522	$ 345	$ 37	$ 2,904

Operating Netback Information

	2009		2008		2007	
	Gas *($/Mcf)*	**Total** *($/Mcfe)*	Gas *($/Mcf)*	Total *($/Mcfe)*	Gas *($/Mcf)*	Total *($/Mcfe)*
Price	**$ 3.71**	**$ 4.02**	$ 8.12	$ 8.63	$ 6.30	$ 6.62
Expenses						
Production and mineral taxes	**0.03**	**0.03**	0.06	0.06	0.08	0.08
Transportation and selling	**0.33**	**0.32**	0.42	0.41	0.42	0.40
Operating	**1.13**	**1.09**	1.15	1.13	1.05	1.03
Netback excluding Realized Financial Hedging	**2.22**	**2.58**	6.49	7.03	4.75	5.11
Realized Financial Hedging Gain (Loss)	**3.16**	**2.93**	(0.30)	(0.36)	0.76	0.65
Netback including Realized Financial Hedging	**$ 5.38**	**$ 5.51**	$ 6.19	$ 6.67	$ 5.51	$ 5.76

Production Volumes



- Natural gas production volumes decreased 6 percent to 1,224 MMcf/d in 2009 compared to 2008.
- Liquids production volumes decreased 21 percent to 15,880 barrels ("bbls") per day ("bbls/d") in 2009 compared to 2008.
- Volumes in 2009 were lower than 2008 primarily as a result of shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment (approximately 120 MMcf/d), natural declines at conventional properties and the volume impact of property divestitures in 2008 and 2009, partially offset by the impact of lower royalties.

Key Resource Plays

	Daily Production			Drilling Activity (net wells drilled)		
	2009	2008	2007	**2009**	2008	2007
Natural Gas *(MMcf/d)*						
Greater Sierra	**199**	220	211	**57**	106	109
Cutbank Ridge	**310**	296	258	**71**	82	93
Bighorn	**159**	167	126	**69**	64	62
CBM	**316**	304	259	**490**	698	1,079
Total *(MMcf/d)*	**984**	987	854	**687**	950	1,343

2009 versus 2008

Operating Cash Flow of $2,658 million decreased $816 million due to:

- A $2,169 million impact resulting from the decrease in commodity prices, excluding the impact of financial hedging, which reflects the changes in benchmark prices and changes in the basis differentials; and
- A $397 million impact resulting from the decrease in natural gas and liquids production volumes;

partially offset by:

- Realized financial hedging gains of $1,400 million in 2009 compared to losses of $186 million in 2008;
- Transportation and selling costs decreased $85 million primarily as a result of reduced volumes transported to the U.S. and the lower U.S./Canadian dollar exchange rate; and
- Operating expenses were $73 million lower primarily as a result of the lower U.S./Canadian dollar exchange rate, reduced repairs and maintenance, workover and chemical costs due to lower activity levels, partially offset by higher long-term compensation costs due to the change in the EnCana share price.

2008 versus 2007

Operating Cash Flow of $3,474 million increased $570 million due to:

- A $1,035 million impact resulting from the increase in commodity prices, excluding the impact of financial hedging, which reflects the changes in benchmark prices and changes in the basis differentials; and
- A $151 million impact resulting from the increase in natural gas and liquids production volumes. Volumes were higher primarily due to drilling success as well as increased tie-in and completion activity in the key resource plays of CBM, Bighorn and Cutbank Ridge, partially offset by natural declines for conventional properties;

partially offset by:

- Realized financial hedging losses of $186 million in 2008 compared to gains of $324 million in 2007; and
- Operating expenses were $74 million higher primarily as a result of higher repairs and maintenance due to scheduled plant turnarounds, increased gathering and processing, salaries and benefits, workovers, property tax and lease costs, offset by lower long-term compensation costs due to the change in the EnCana share price.

Capital Investment

2009 versus 2008

Capital investment of $1,869 million during 2009 was primarily focused on the CBM, Cutbank Ridge, Greater Sierra and Bighorn key resource plays and Deep Panuke. The $590 million decrease compared to 2008 was primarily due to lower drilling and completion costs as well as the lower U.S./Canadian dollar exchange rate, partially offset by higher activity in Deep Panuke. The number of net wells drilled in the Canadian Division in 2009 decreased to 699 from 1,064 in 2008.

2008 versus 2007

Capital investment of $2,459 million in 2008 was relatively unchanged compared to 2007. Lower activity levels were offset by increased capital inventory purchases. The number of net wells drilled in the Canadian Division in 2008 decreased to 1,064 from 1,539 in 2007.

USA Division

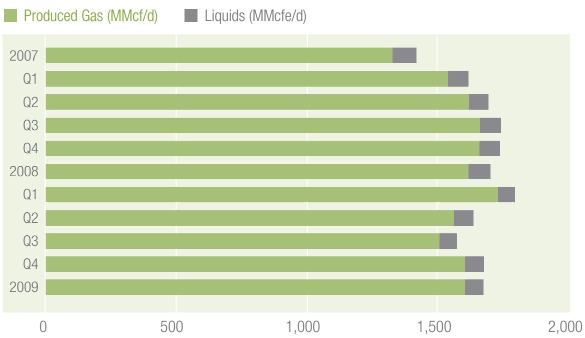
Financial Results

	2009				2008				2007			
($ millions)	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total
Revenues, Net of Royalties and Hedging	$ 2,210	$ 201	$ 114	$ 2,525	$ 4,718	$ 407	$ 288	$ 5,413	$ 2,641	$ 309	$ 298	$ 3,248
Realized Financial Hedging Gain (Loss)	2,012	–	–	2,012	216	–	–	216	1,124	–	–	1,124
Expenses												
Production and mineral taxes	100	18	–	118	334	36	–	370	167	22	–	189
Transportation and selling	530	–	–	530	502	–	–	502	307	–	–	307
Operating	327	–	107	434	352	–	266	618	323	–	272	595
Operating Cash Flow	$ 3,265	$ 183	$ 7	$ 3,455	$ 3,746	$ 371	$ 22	$ 4,139	$ 2,968	$ 287	$ 26	$ 3,281

Operating Netback Information

	2009		2008		2007	
	Gas *($/Mcf)*	Total *($/Mcfe)*	Gas *($/Mcf)*	Total *($/Mcfe)*	Gas *($/Mcf)*	Total *($/Mcfe)*
Price	**$ 3.75**	**$ 3.92**	$ 7.89	$ 8.17	$ 5.38	$ 5.65
Expenses						
Production and mineral taxes	**0.17**	**0.19**	0.56	0.59	0.34	0.36
Transportation and selling	**0.90**	**0.86**	0.84	0.80	0.62	0.59
Operating	**0.55**	**0.53**	0.59	0.56	0.65	0.62
Netback excluding Realized Financial Hedging	**2.13**	**2.34**	5.90	6.22	3.77	4.08
Realized Financial Hedging Gain (Loss)	**3.41**	**3.27**	0.36	0.34	2.29	2.15
Netback including Realized Financial Hedging	**$ 5.54**	**$ 5.61**	$ 6.26	$ 6.56	$ 6.06	$ 6.23

Production Volumes



- Natural gas production volumes decreased 1 percent to 1,616 MMcf/d in 2009 compared to 2008. Drilling and operational success in the Haynesville shale play and East Texas were offset by shut-in and curtailed production as well as delayed well completions and tie-ins due to the low price environment (approximately 200 MMcf/d).
- Liquids production volumes decreased 15 percent to 11,317 bbls/d in 2009 compared to 2008.

Key Resource Plays

	Daily Production			Drilling Activity (net wells drilled)		
	2009	2008	2007	**2009**	2008	2007
Natural Gas *(MMcf/d)*						
Jonah	**571**	603	557	**108**	175	135
Piceance	**362**	385	348	**129**	328	286
East Texas	**324**	334	143	**38**	78	35
Fort Worth	**136**	142	124	**26**	83	75
Total *(MMcf/d)*	**1,393**	1,464	1,172	**301**	664	531

Natural gas production volumes in the Haynesville shale play, which has not yet been designated a key resource play, averaged 70 MMcf/d in 2009 compared to 9 MMcf/d in 2008, and exited 2009 at approximately 125 MMcf/d.

2009 versus 2008

Operating Cash Flow of $3,455 million decreased $684 million due to:

- A $2,589 million impact resulting from the decrease in commodity prices, excluding the impact of financial hedging, which reflects the changes in benchmark prices and changes in the basis differentials; and
- A $125 million impact resulting from the decrease in natural gas and liquids production volumes;

partially offset by:

- Realized financial hedging gains of $2,012 million in 2009 compared to gains of $216 million in 2008;
- Production and mineral taxes decreased $252 million primarily as a result of lower commodity prices and high cost well tax credits; and
- Operating expenses were $184 million lower as a result of shut-in production and less activity resulting in lower repairs and maintenance, labour, water disposal and workover costs, partially offset by higher long-term compensation costs due to the change in the EnCana share price.

2008 versus 2007

Operating Cash Flow of $4,139 million increased $858 million due to:

- A $1,618 million impact resulting from the increase in commodity prices, excluding the impact of financial hedging, which reflects the changes in benchmark prices and changes in the basis differentials; and
- A $557 million impact resulting primarily from the increase in natural gas production volumes. Volumes were higher primarily due to drilling and operational success at East Texas, Jonah, Piceance and Fort Worth as well as incremental volumes from the Deep Bossier acquisition and upgrades to the compression and gathering facilities at Jonah. These increases were slightly offset by the impact of shut-in production (approximately 100 MMcf/d) at Piceance and Jonah during the fourth quarter of 2008 due to the low price environment;

partially offset by:

- Realized financial hedging gains of $216 million in 2008 compared to gains of $1,124 million in 2007;
- Production and mineral taxes increased $181 million primarily as a result of higher natural gas prices; and
- Transportation and selling costs increased $195 million primarily as a result of higher unutilized transportation commitments as well as transporting gas greater distances on the Rockies Express Pipeline to improve price realizations.

Capital Investment

2009 versus 2008

Capital investment of $1,821 million during 2009 was primarily focused on the East Texas and Jonah key resource plays, as well as on the emerging Haynesville shale play. The $861 million decrease compared to 2008 was primarily due to lower activity in the Piceance, East Texas, Jonah and Fort Worth key resource plays, partially offset by increased drilling and facility spending in the Haynesville shale play. The number of net wells drilled in the USA Division in 2009 decreased to approximately 390 from 750 in 2008. During 2009, EnCana also established an entry level land position in the Marcellus shale play in Pennsylvania.

2008 versus 2007

Capital investment of $2,682 million in 2008 increased $747 million primarily due to increased drilling and completion activity in the East Texas, Piceance and Jonah key resource plays, including incremental costs from the Deep Bossier acquisition offset slightly by lower capitalized long-term compensation costs. The number of net wells drilled in the USA Division in 2008 increased to 750 from 644 in 2007.

Other Operations

As a result of the November 30, 2009 Split Transaction, upstream assets formerly included in Canadian Plains and Integrated Oil – Canada are presented in continuing operations as Canada – Other under full cost accounting. Accordingly, 2009 includes 11 months of reported results compared to 12 months in 2008.

CANADA – OTHER

Financial Results

	2009				2008				2007			
($ millions)	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total	Gas	Liquids	Other	Total
Revenues, Net of Royalties and Hedging	$ 922	$ 2,249	$ 68	$ 3,239	$ 2,392	$ 3,440	$ 185	$ 6,017	$ 1,946	$ 2,321	$ 226	$ 4,493
Realized Financial Hedging Gain (Loss)	859	38	87	984	(91)	(217)	(14)	(322)	240	(130)	26	136
Expenses												
Production and mineral taxes	15	23	1	39	36	38	1	75	34	29	–	63
Transportation and selling	37	535	24	596	71	847	45	963	82	629	35	746
Operating	186	356	40	582	241	409	74	724	221	374	74	669
Purchased Product	–	–	(85)	(85)	–	–	(151)	(151)	–	–	(88)	(88)
Operating Cash Flow	$ 1,543	$ 1,373	$ 175	$ 3,091	$ 1,953	$ 1,929	$ 202	$ 4,084	$ 1,849	$ 1,159	$ 231	$ 3,239

Production Volumes

	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1	2007
Produced Gas *(MMcf/d)*	762	517	826	864	842	905	879	892	923	925	966
Liquids *(bbls/d)*	99,900	75,382	113,028	106,330	105,042	100,250	103,317	99,756	93,966	103,933	101,702
Total *(MMcfe/d)* (1)	1,362	970	1,504	1,502	1,472	1,507	1,499	1,491	1,487	1,549	1,576

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

Operating Cash Flow in 2009 decreased $993 million primarily as a result of the decrease in commodity prices and one month less of reported activity.

Natural gas production volumes in 2009 decreased 16 percent primarily as a result of natural declines and one month less of activity. Liquids production volumes in 2009 were relatively unchanged compared to 2008 as a result of higher volumes from Foster Creek/Christina Lake, offset by one month less of reported activity.

Depreciation, Depletion and Amortization

($ millions)	2009	2008	2007
Canada	$ 1,980	$ 2,198	$ 2,298
USA	1,561	1,691	1,181
Market Optimization	20	15	17
Corporate & Other	143	131	161
Total DD&A	$ 3,704	$ 4,035	$ 3,657
Pro Forma DD&A (1)	$ 2,770	$ 3,096	

(1) Pro Forma DD&A expenses exclude the DD&A expenses related to the assets transferred to Cenovus under the Split Transaction and reflect an adjustment arising from a change in the depletion rate calculated for EnCana's Canadian cost centre.

Upstream DD&A

EnCana uses full cost accounting for oil and gas activities and calculates DD&A on a country-by-country cost centre basis.

2009 versus 2008

Upstream DD&A expenses of $3,541 million in 2009 decreased $348 million compared to 2008 due to:

- DD&A expenses in Canada were lower primarily as a result of lower production volumes and the lower U.S./Canadian dollar exchange rate, partially offset by higher DD&A rates resulting from higher future development costs; and
- DD&A expenses in the USA were lower primarily due to lower DD&A rates resulting from lower future development costs and higher proved reserves.

2008 versus 2007

Upstream DD&A expenses of $3,889 million in 2008 increased $410 million compared to 2007 due to:

- Production volumes increased 6 percent; and
- DD&A rates for the USA were higher primarily due to higher capitalized costs, mainly attributable to the Deep Bossier acquisition. DD&A rates in Canada for 2008 were lower than 2007 primarily as a result of the higher proved reserves.

Market Optimization

Financial Results

($ millions)	Consolidated 2009	2008	2007
Revenues	$ 1,607	$ 2,655	$ 2,944
Expenses			
Transportation and selling	–	–	10
Operating	26	45	37
Purchased product	1,545	2,577	2,858
Operating Cash Flow	36	33	39
DD&A	20	15	17
Segment Income	$ 16	$ 18	$ 22

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

Revenues and purchased product expenses decreased in 2009 compared to 2008 mainly due to decreased pricing, partially offset by increases in volume required for Market Optimization. The decreases in 2008 compared to 2007 were mainly due to overall volume decreases required for Market Optimization, partially offset by increased pricing.

Corporate and Other

Financial Results

($ millions)	Consolidated 2009	2008	2007
Revenues	$ (2,615)	$ 2,719	$ (1,239)
Expenses			
Operating	49	(13)	14
DD&A	143	131	161
Segment Income (Loss)	$ (2,807)	$ 2,601	$ (1,414)

Revenues represent primarily unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

Operating expenses in 2009 primarily relate to mark-to-market losses on long-term power generation contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements. DD&A also includes impairments related to international exploration prospects.

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

($ millions)	Consolidated 2009	2008	2007
Revenues			
Natural Gas	$ (2,538)	$ 2,475	$ (1,049)
Crude Oil	(102)	242	(190)
	(2,640)	2,717	(1,239)
Expenses	40	(12)	(4)
	(2,680)	2,729	(1,235)
Income Tax Expense (Recovery)	(888)	911	(424)
Unrealized Mark-to-Market Gains (Losses), after-tax	$ (1,792)	$ 1,818	$ (811)

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curves of commodity prices and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 20 to the Consolidated Financial Statements.

Expenses

	Pro Forma (1)		Consolidated		
($ millions)	**2009**	2008	**2009**	2008	2007
Administrative	**$ 359**	$ 329	**$ 477**	$ 447	$ 356
Interest, net	**371**	368	**405**	402	234
Accretion of asset retirement obligation	**37**	40	**71**	77	63
Foreign exchange (gain) loss, net	**(312)**	673	**(22)**	423	(164)
(Gain) loss on divestitures	**2**	(143)	**2**	(141)	(65)
Total Expenses	**$ 457**	$ 1,267	**$ 933**	$ 1,208	$ 424

(1) Pro Forma expenses exclude the expenses related to the oil and gas assets transferred to Cenovus under the Split Transaction and reflect adjustments for compensation costs and transaction costs.

2009 versus 2008

Consolidated expenses of $933 million decreased $275 million due to:

- Foreign exchange losses of $95 million and gains of $22 million in the fourth quarter and full year of 2009, respectively, compared to losses of $253 million and $423 million in the fourth quarter and full year of 2008, respectively, were primarily due to the effects of the U.S./Canadian dollar exchange rate on U.S. dollar denominated debt issued from Canada, offset by revaluation of the partnership contribution receivable, settlement of foreign currency denominated intercompany transactions and revaluation of monetary items. Pro forma foreign exchange excludes the impact of foreign exchange on the partnership contribution receivable as it was transferred to Cenovus under the Split Transaction.
- Administrative expenses increased primarily as a result of higher long-term compensation costs, partially offset by the lower U.S./Canadian dollar exchange rate. Fourth quarter 2009 administrative expenses of $145 million were higher than fourth quarter 2008 expenses of $67 million primarily due to higher long-term compensation costs, increased costs related to the Split Transaction and the higher U.S./Canadian dollar exchange rate.
- The gain on divestitures in 2008 relates primarily to the divestiture of interests in Brazil. Additional detail on gains and losses on divestitures can be found in the Acquisitions and Divestitures section of this MD&A.

2008 versus 2007

Consolidated expenses of $1,208 million increased $784 million due to:

- Foreign exchange losses of $253 million and $423 million in the fourth quarter and full year of 2008, respectively, are primarily due to the effects of the U.S./Canadian dollar exchange rate on U.S. dollar denominated debt issued from Canada, offset by revaluation of the partnership contribution receivable.
- Net interest expense increased primarily as a result of higher weighted average outstanding debt. EnCana's 2008 weighted average interest rate on outstanding debt was 5.5 percent compared to 5.6 percent in 2007.
- Administrative expenses increased primarily due to higher staff levels and one time charges for legal settlements, offset by lower long-term compensation costs as a result of the change in the EnCana share price. The proposed corporate reorganization also added costs for work needed to prepare for the transaction. Fourth quarter 2008 administrative expenses of $67 million was lower than fourth quarter 2007 expenses of $96 million primarily due to lower long-term compensation costs and the lower U.S./Canadian dollar exchange rate, partially offset by costs for the proposed corporate reorganization and other related costs due to growth.

Income Tax

	Pro Forma		Consolidated		
	2009	2008	**2009**	2008	2007
Effective Tax Rate	**13.0%**	35.4%	**5.6%**	29.5%	16.5%
($ millions)					
Current Income Tax	**$ 550**	$ 568	**$ 1,908**	$ 997	$ 1,380
Future Income Tax	**(438)**	1,297	**(1,799)**	1,723	(698)
Total Income Tax	**$ 112**	$ 1,865	**$ 109**	$ 2,720	$ 682

2009 versus 2008

Consolidated total income tax expense in 2009 was $2,611 million lower than in 2008 primarily due to lower Net Earnings Before Income Tax.

Consolidated current income tax expense in 2009 was $911 million higher than in 2008. This reflects incremental current tax expense related to the wind-up of the Canadian oil and gas partnership and increased realized hedging gains, offset by lower commodity prices and volumes.

Consolidated future income tax expense in 2009 was $3,522 million lower than in 2009 primarily due to the reversal of the unrealized hedging gain and the wind-up of the Canadian oil and gas partnership.

2008 versus 2007

The 2007 effective tax rate was lower primarily due to a one time Canadian federal corporate legislative change and a reduction in the Canadian federal corporate tax rates.

Consolidated current income tax expense in 2008 was $383 million lower than in 2007. This is comprised of $562 million related to the increased benefits from international financing and a U.S. tax legislative change in 2008 that allows an accelerated write-off of certain capital expenditures, offset by a one time tax recovery of $179 million in 2007 for a Canadian tax legislative change.

Consolidated future income tax expense in 2008 was $2,421 million higher than in 2007 primarily due to the increased unrealized mark-to-market hedging gains and the accelerated write-offs for certain U.S. capital expenditures as well as the reduction of the Canadian federal corporate tax rates in 2007.

EnCana's effective rate in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration "permanent differences", adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

- The non-taxable portion of Canadian capital gains or losses;
- International financing; and
- Foreign exchange (gains) losses not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

Capital Investment

Capital investment in 2009, 2008 and 2007 were primarily directed towards business information systems, leasehold improvements and office furniture. On February 9, 2007, EnCana announced that it had entered into a 25-year lease agreement with a third-party developer for The Bow office project. Cost-of-design changes to the building and leasehold improvements are shared by EnCana and Cenovus.

Discontinued Operations

EnCana has rationalized its operations to focus on upstream activities in North America, resulting in divestitures which are accounted for as Discontinued Operations. EnCana's 2009 Net Earnings from Discontinued Operations were $32 million (2008 – $555 million loss; 2007 – $512 million). Additional information on Discontinued Operations can be found in Note 6 to the Consolidated Financial Statements.

Downstream Refining

As a result of the November 30, 2009 Split Transaction, EnCana's operations are focused on natural gas activities which excludes refining assets, and accordingly, has reported results from Downstream Refining as Discontinued Operations. Downstream Refining focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. These refineries were jointly owned with ConocoPhillips.

Midstream

The $75 million gain on discontinuance in 2007 is the result of an expired clause included in the December 2005 sale of the Company's Midstream NGLs processing operations. The clause provided potential market price support for the facilities and was accrued for in 2005.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2009	2008	2007
Net cash from (used in)			
Operating activities	$ 7,873	$ 8,986	$ 8,262
Investing activities	(4,806)	(7,542)	(8,179)
Financing activities	835	(1,439)	(119)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	19	(33)	16
Increase (decrease) in cash and cash equivalents	$ 3,921	$ (28)	$ (20)
Pro Forma net cash from Operating activities	$ 5,041	$ 6,224	

Operating Activities

Net cash from operating activities decreased $1,113 million in 2009 compared to 2008. Cash Flow was $6,779 million during 2009 compared to $9,386 million in 2008. Reasons for this change are discussed under the Consolidated Cash Flow section of this MD&A. Cash from operating activities were also impacted by net changes in other assets and liabilities, net changes in non-cash working capital and net changes in non-cash working capital from Discontinued Operations.

Excluding the impact of current risk management assets and liabilities, the Company had a working capital surplus of $1,348 million at December 31, 2009 compared to a deficit of $1,067 million at December 31, 2008. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used for investing activities in 2009 decreased $2,736 million compared to 2008.

Capital expenditures, including property acquisitions, decreased $3,109 million in 2009 compared to 2008 and proceeds from divestitures increased $274 million in 2009 compared to 2008. Reasons for these changes are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

Following the Split Transaction, EnCana received amounts due from Cenovus and invested the net proceeds of approximately $3,750 million in short-term marketable securities ("Cenovus Notes").

Financing Activities

In conjunction with the Split Transaction, on September 18, 2009, Cenovus completed a private offering of senior unsecured notes for an aggregate principal amount of $3,500 million. The net proceeds of the private offering were placed into an escrow account to be released to Cenovus upon completion of the Split Transaction. The underwriters deposited $3,468 million and Cenovus contributed $151 million to the escrow account for total funds of $3,619 million. The funds were released to Cenovus upon completion of the Split Transaction. Cenovus used the funds to settle the Cenovus Notes due to EnCana as described above.

Excluding the Cenovus Notes, net repayment of long-term debt in 2009 was $1,606 million compared to net issuance of $6 million in 2008. EnCana's total long-term debt including current portion was $7,768 million at December 31, 2009 compared to $9,005 million at December 31, 2008.

On May 4, 2009, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of $500 million. The notes have a coupon rate of 6.5 percent and mature on May 15, 2019. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

EnCana maintains two committed bank credit facilities and a Canadian and a U.S. dollar shelf prospectus.

As at December 31, 2009, EnCana had available unused committed bank credit facilities in the amount of $4.9 billion. EnCana has in place a revolving bank credit facility for C$4.5 billion that remains committed through October 2012. One of EnCana's U.S. subsidiaries has in place a revolving bank credit facility for $565 million that remains committed through February 2013.

On May 21, 2009, EnCana renewed a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. At December 31, 2009, C$2.0 billion ($1.9 billion) of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus expires in June 2011.

EnCana has in place a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the United States. At December 31, 2009, $3.5 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus was renewed in March 2008 and expires in April 2010.

As at December 31, 2009, EnCana had available unused capacity under shelf prospectuses for up to $5.4 billion.

EnCana is currently in compliance with and anticipates that it will continue to be in compliance with all financial covenants under its credit facility agreements and indentures.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On November 30, 2009 following the completion of the Split Transaction, Standard & Poor's Ratings Services lowered the rating to "BBB+" from "A-" and changed the outlook to "Stable" from "CreditWatch" with negative implications. Moody's Investors Service affirmed the rating of "Baa2" with a "Stable" outlook. DBRS Limited maintained the rating of "A (low)" and changed the outlook to "Stable" from "Under Review with Developing Implications". These credit ratings remained unchanged at December 31, 2009.

EnCana has obtained regulatory approval under Canadian securities laws to purchase up to approximately 37.5 million Common Shares under a Normal Course Issuer Bid ("NCIB"), which commenced on December 14, 2009 and expires on December 13, 2010. During 2009, under the NCIB and a prior NCIB, EnCana did not purchase any of its Common Shares compared to 4.8 million Common Shares purchased for total consideration of approximately $326 million in 2008. Shareholders may obtain a copy of the Company's Notice of Intention to make a Normal Course Issuer Bid by contacting investor.relations@encana.com.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments in 2009 were $1,051 million (2008 – $1,199 million; 2007 – $603 million) or $1.40 per share (2008 – $1.60 per share; 2007 – $0.80 per share). From the first quarter of 2008 to the completion of the Split Transaction, EnCana paid a quarterly dividend of $0.40 per share. On December 31, 2009, after the Split Transaction, EnCana paid a quarterly dividend of $0.20 per share. The Board of Directors of Cenovus also declared a dividend of $0.20 per share payable on December 31, 2009 to Cenovus common shareholders. These dividends were funded by Cash Flow.

Debt to Capitalization and Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times. At December 31, 2009, the Company's Debt to Capitalization ratio and consolidated Debt to Adjusted EBITDA were within these targets. The Company's pro forma Debt to Adjusted EBITDA was slightly higher than its target primarily due to the depressed natural gas prices experienced during 2009.

Financial Metrics

	Pro Forma	Consolidated		
	2009	**2009**	2008	2007
Debt to Capitalization (1)(2)	**32%**	**32%**	28%	32%
Debt to Adjusted EBITDA (times) (1)(3)	**2.1x**	**1.3x**	0.6x	1.2x

(1) Debt is defined as Long-Term Debt including current portion.

(2) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Shareholders' Equity.

(3) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

EnCana had approximately $4.3 billion in cash and short-term investments primarily as a result of a corporate reorganization more fully described in EnCana's Business section of this MD&A. The Company repaid all of its short-term debt during 2009 and expects to use part of its cash balance to pay its current income tax liability of approximately $1.8 billion in February 2010.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

Contractual Obligations and Commitments [(1)]

	Expected Payment Date				
($ millions)	2010	2011 to 2012	2013 to 2014	2015+	Total
Long-Term Debt [(2)]	$ 200	$ 978	$ 1,500	$ 5,116	$ 7,794
Asset Retirement Obligation	41	72	98	3,581	3,792
Pipeline Transportation	438	991	998	1,911	4,338
Purchase of Goods and Services	377	640	422	684	2,123
Operating Leases [(3)]	69	158	329	3,238	3,794
Capital Commitments	127	236	38	–	401
Other Long-Term Commitments	2	4	3	24	33
Total	$ 1,254	$ 3,079	$ 3,388	$ 14,554	$ 22,275
Cenovus's Share of Costs [(4)]	$ 90	$ 179	$ 148	$ 1,576	$ 1,993

(1) In addition, the Company has made commitments related to its risk management program. See Note 20 to the Consolidated Financial Statements. The Company has an obligation to fund its defined benefit pension and Other Post-Employment Benefit plans as disclosed in Note 19 to the Consolidated Financial Statements.

(2) Principal component only. See Note 15 to the Consolidated Financial Statements.

(3) Primarily related to office space associated with The Bow.

(4) Tenant costs associated with The Bow as well as current office space lease arrangements remain with EnCana. Cenovus and EnCana have entered into an agreement to share in the costs.

EnCana has entered into various commitments primarily related to demand charges for firm transportation, leasing of office space, procurement arrangements for goods and services, as well as other minor spending commitments. EnCana and Cenovus have entered into an arrangement whereby the portion of the commitments related to the Cenovus operations have been transferred to Cenovus as a result of the Split Transaction and are excluded from the table above.

The Company expects its 2010 commitments to be funded from Cash Flow.

Leases

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes. As a result of the Split Transaction, EnCana has agreed to sub-lease a portion of its corporate office space and obtains rent from Cenovus based on a preset formula. This is included in revenue in the Corporate and Other segment.

Variable Interest Entities ("VIEs")

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Haynesville represented an interest in a VIE from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest was completed, the assets were transferred to EnCana.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

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

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. All but one of these lawsuits had been settled prior to 2009. Without admitting any liability whatsoever, the remaining lawsuit was settled on October 16, 2009.

OUTLOOK

EnCana plans to focus on growing natural gas production from its diversified portfolio of existing and emerging unconventional resource plays in North America.

EnCana remains highly focused on key business objectives of maintaining financial strength, optimizing capital investments and continuing to pay a stable dividend to shareholders – attained through a disciplined approach to capital spending, a flexible investment program and financial stewardship. EnCana has been consistently among the lowest cost companies in the natural gas industry and has a history of entering resource plays early and leveraging technology to unlock unconventional resources.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs.

EnCana's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on 2010 results is available in the Corporate Guidance on the Company's website at www.encana.com.

RISK MANAGEMENT

EnCana's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

- financial risks;
- operational risks; and
- safety, environmental and regulatory risks.

Issues affecting, or with the potential to affect, EnCana's reputation are generally of a strategic nature or emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. EnCana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear policies, procedures, guidelines and responsibilities for identifying and managing these issues.

EnCana has a strong financial position and continues to implement its business model of focusing on developing low-risk and low-cost long-life resource plays, which allows the Company to respond well to market uncertainties. Management adjusts financial and operational risk strategies to proactively respond to changing economic conditions and to mitigate or reduce risk.

Financial Risks

EnCana defines financial risks as the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on EnCana's business.

Financial risks include, but are not limited to:

- Market pricing of natural gas;
- Credit and liquidity;
- Foreign exchange; and
- Interest rates.

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

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 to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

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

To partially mitigate the natural gas commodity price risk, the Company enters into swaps, which fix NYMEX prices. To help protect against varying natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points. Further information, including the details of EnCana's financial instrument holdings as of December 31, 2009, is disclosed in Note 20 to the Consolidated Financial Statements.

Counterparty and credit risks are regularly and proactively managed. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry. 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 according to counterparties' credit quality and transactions that are fully collateralized.

EnCana closely monitors the Company's ability to access cost effective credit and that sufficient cash resources are in place to fund capital expenditures and fund dividend payments. The Company manages liquidity risk through cash and debt management programs, including maintaining a strong balance sheet and significant unused credit facilities. The Company also has access to a wide range of funding alternatives at competitive rates, including commercial paper, capital market debt and bank loans. EnCana maintains investment grade credit ratings on its senior unsecured debt.

As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, EnCana may enter into foreign exchange contracts. 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. By maintaining U.S. and Canadian operations, EnCana has a natural hedge to some foreign exchange exposure.

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 may enter into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Typically, the Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana may enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

Operational Risks

Operational risks are defined as the risk of loss or lost opportunity resulting from the following:

- Reserve replacement;
- Capital activities; and
- Operating activities.

The Company's ability to operate, generate cash flows, complete projects, and value reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If EnCana fails to acquire or find additional natural gas reserves, its reserves and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, 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 thorough review of its previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that 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 results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

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.

When making operating and investing decisions, EnCana's business model allows flexibility in capital allocation to optimize investments focused on project returns, long-term value creation, and risk mitigation. EnCana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

Safety, Environmental and Regulatory Risks

The Corporation's business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas and liquids and the operation of midstream facilities. The Company is committed to safety in its operations and has high regard for the environment and stakeholders, including regulators. 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, security 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 provides recommended environmental policies for approval by EnCana's Board of Directors 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 audits, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to environmental events and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a Security Program designed to protect EnCana's personnel and assets.

EnCana has 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, accounting or internal control matters.

EnCana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion, including hydraulic fracturing and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Company's existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by the operating divisions and corporate groups. EnCana's compliance with the required laws and regulations is monitored by EnCana's legal group, which stays abreast of new developments and changes in laws and regulations to ensure that EnCana continues to comply with prescribed laws and regulations. Of note in this regard currently is EnCana's approach to changes in regulations relating to climate change and royalty frameworks as discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, EnCana maintains relationships with key stakeholders and conducts other mitigation initiatives mentioned herein.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating and capital costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, EnCana has one facility covered under the emissions regulations. The forecast cost of carbon associated with the Alberta regulations is not material to EnCana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate started at C$10 per tonne of carbon equivalent emissions, is currently C$15 per tonne and rises to C$30 per tonne by 2012. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

The American Clean Energy and Security Act ("ACESA") was passed by the House of Representatives on June 26, 2009. This climate change legislation would establish a GHG cap-and-trade system and provide incentives for the development of renewable energy. The House Act aims to reduce GHG emissions by 17 percent from 2005 levels by 2020, and 83 percent by 2050. The Senate version of the climate bill, however, is still in progress. Once the Senate completes its work, the House and Senate bills will need to be reconciled and submitted to the U.S. Administration for final approval. EnCana will continue to monitor these developments closely during 2010.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on the following key elements:

- significant production weighting in natural gas;
- focus on energy efficiency and the development of technology to reduce GHG emissions; and
- involvement in the creation of industry best practices.

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

- **Manage Existing Costs**
  When regulations are implemented, a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking and attention to fuel consumption help to support and drive its focus on cost reduction.
- **Respond to Price Signals**
  As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, EnCana is also attempting, where appropriate, to realize the associated value of its reduction projects.
- **Anticipate Future Carbon Constrained Scenarios**
  EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios influence EnCana's long range planning and its analyses on the implications of regulatory trends.

EnCana incorporates the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that GHG regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analyses. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on the Company's website at www.encana.com.

ACCOUNTING POLICIES AND ESTIMATES

New Accounting Standards Adopted

On January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in Note 2 to the Consolidated Financial Statements.

International Financial Reporting Standards ("IFRS")

EnCana's IFRS Changeover Plan

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information.

The key elements of EnCana's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

During 2009, EnCana made significant progress on its changeover plan. The Company analyzed accounting policy alternatives and preliminarily drafted its IFRS accounting policies. Process and system changes have been designed for significant areas of impact, with internal control requirements taken into account. Information system changes have been tested. IFRS education sessions have been held with internal stakeholders.

Process and system changes will be implemented in early 2010 to ensure IFRS comparative data is captured. EnCana's IFRS accounting policies are expected to be finalized mid-2010. Quantification of IFRS impacts will then be determined utilizing previously captured data. Communication of impacts to external stakeholders is expected to occur in the latter half of 2010.

EnCana will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board.

Expected Accounting Policy Impacts

EnCana's significant areas of impact continue to include property, plant and equipment ("PP&E"), asset retirement obligation ("ARO"), impairment testing, stock-based compensation and income taxes. These areas of impact have the greatest potential impact to the Company's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, *First-time Adoption of International Financial Reporting Standards*. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements.

Property, Plant and Equipment

Under Canadian GAAP, EnCana follows the CICA's guideline on full cost accounting in which all costs directly associated with the acquisition of, the 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 country cost centre are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, EnCana will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Currently, EnCana capitalizes and depletes pre-exploration costs within the country cost centre. In 2008 and 2009, these costs were not material to EnCana.

Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, EnCana will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E. Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, EnCana will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the country cost centre level currently utilized under Canadian GAAP. EnCana has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, upstream divestures will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded.

EnCana expects to adopt the IFRS 1 exemption, which allows the Company to deem its January 1, 2010 IFRS upstream asset costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs will be equal to the Canadian GAAP unproved properties balance and the IFRS development costs will be equal to the full cost pool balance. EnCana will allocate this upstream full cost pool over reserves to establish the area level depletion units.

Asset Retirement Obligation

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. Existing liabilities are not re-measured using current discount rates. Under IFRS, ARO is measured as the best estimate of the expenditure to be incurred and requires the use of current discount rates at each re-measurement date. Generally, the change in discount rates results in a balance being added to or deducted from PP&E.

As a result of EnCana's intended use of the IFRS 1 upstream assets exemption, the Company is required to revalue its January 1, 2010 ARO balance and recognize the adjustment in retained earnings.

Impairment

Under Canadian GAAP, EnCana is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties.

Under IFRS, EnCana is required to recognize and measure an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount. EnCana will group its upstream assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

Stock-Based Compensation

Share units issued under EnCana's stock-based compensation plans that are accounted for using the intrinsic value method under Canadian GAAP will be required to be fair valued under IFRS. The intrinsic value of a share unit is the amount by which EnCana's stock price exceeds the exercise price of a share unit. The fair value of a share unit is determined utilizing a model, such as the Black-Scholes-Merton model.

EnCana intends to use the IFRS 1 exemption under which share units that vest prior to January 1, 2010 are not required to be retrospectively restated.

Income Taxes

In transitioning to IFRS, the Company's future tax liability will be impacted by the tax effects resulting from the IFRS changes discussed above. EnCana continues to assess the impact that the IFRS income tax principles may have on the Company.

Other IFRS 1 Considerations

As permitted by IFRS 1, EnCana's foreign currency translation adjustment, currently the only balance in EnCana's Accumulated Other Comprehensive Income, will be deemed to be zero and the balance will be reclassified to retained earnings on January 1, 2010. Accordingly, retrospective restatement of foreign currency translation adjustments under IFRS principles will not be performed.

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles.

With respect to employee benefit plans, cumulative unamortized actuarial gains and losses are expected to be charged to retained earnings on January 1, 2010. As such, they will not be retrospectively recalculated using IFRS principles.

Other Recent Accounting Pronouncements

Business Combinations

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1582 "Business Combinations", which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1601 "Consolidated Financial Statements", which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Non-controlling Interests

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1602 "Non-controlling Interests", which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

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 and Oil and Gas Reserves

As previously described, EnCana follows full cost accounting for oil and gas activities. Reserves estimates can have a significant impact on earnings, as they are a key input to the Company's DD&A calculations and impairment tests. A downward revision in reserves estimate could result in a higher DD&A charge against net earnings. An impairment of upstream assets is recognized when the net capitalized costs exceed the undiscounted cash flows from proved reserves for a country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties. A downward revision in reserves estimates could result in the recognition of an impairment charged against retained earnings. As at December 31, 2009, EnCana has determined that no write-down to its upstream assets is required under Canadian GAAP.

All of EnCana's oil and gas reserves and resources are evaluated and reported on by independent qualified reserves 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. Reserves 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. Contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable time frame. Estimated recovery for leases assigned contingent resources considers detailed reservoir and pilot studies, demonstrated commercial success of analogous commercial projects and drilling density.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the requirement to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. The asset retirement cost 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. 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.

The fair value settlement recorded for asset retirement obligations is estimated by discounting the expected future cash flows. The discounted cash flows are based on estimates of reserve lives, retirement costs, the weighted average credit-adjusted risk-free rate and future inflation rate. Actual expenditures incurred are charged against the accumulated obligation. The estimates outlined above will impact earnings through accretion on the asset retirement liability in addition to the depletion of the asset retirement cost included in PP&E.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by EnCana for impairment at least annually. 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.

The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions on commodity prices, oil and gas reserves, future expenses and discount rates. EnCana has assessed its goodwill for impairment as at December 31, 2009 and has determined that no write-down is required.

Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are estimated and 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 net earnings in the period that the change occurs.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense and the future income tax assets and liabilities.

Derivative Financial Instruments

As described in the Risk Management section of this MD&A, 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.

Derivative instruments that do not qualify or are not designated as hedges are recorded at fair value. 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 related to natural gas and crude oil 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 estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

In 2007 through to 2009, the Company elected not to designate any of its price risk management activities as accounting hedges and, accordingly, fair valued all derivative instruments with the change in fair value recorded in net earnings.

Pro Forma Information

The objective of EnCana's pro forma information is to illustrate the impact of the Split Transaction on the Company's results by adjusting the historical information to assume the Split Transaction occurred on January 1, 2008. EnCana's pro forma results exclude the results of operations from assets transferred to Cenovus as part of the Split Transaction and reflect expected changes to EnCana's historical results that would arise from the Split Transaction, including income tax, DD&A and transaction costs.

EnCana's pro forma financial information is derived from EnCana's pro forma financial statements, which have been prepared using guidance issued by the U.S. SEC and the Canadian Securities Administrators.

RECONCILIATIONS OF NON-GAAP MEASURES

Pro Forma

Summary of Pro Forma Cash Flow

($ millions)	2009	2008
Pro Forma Cash From Operating Activities	$ 5,041	$ 6,224
(Add back) deduct:		
Net change in other assets and liabilities	38	(173)
Net change in non-cash working capital from Continuing Operations	(18)	43
Pro Forma Cash Flow	$ 5,021	$ 6,354

Reconciliation of Consolidated Cash Flow to Pro Forma Cash Flow

($ millions)		2009	2008
Cash Flow		$ 6,779	$ 9,386
Less: Cenovus Carve-out (1)		2,232	3,088
Add/(Deduct) Pro Forma adjustments		474	56
Pro Forma Cash Flow		5,021	6,354
Per share amounts			
Cash Flow	– Basic	9.03	12.51
	– Diluted	9.02	12.48
Pro Forma Cash Flow	– Basic	6.69	8.47
	– Diluted	6.68	8.45

(1) Cenovus Energy was spun-off on November 30, 2009. As a result, year-to-date information is for the 11 months ended November 30, 2009.

Summary of Pro Forma Operating Earnings

	2009		2008	
($ millions, except per share amounts)		Per share (4)		Per share (4)
Pro Forma Net Earnings, as reported	$ 749	$ 1.00	$ 3,405	$ 4.53
Add back (losses) and deduct gains:				
Unrealized mark-to-market accounting gain (loss), after-tax	(1,352)	(1.80)	1,299	1.73
Non-operating foreign exchange gain (loss), after-tax (2)	334	0.45	(598)	(0.80)
Gain (loss) on discontinuance, after-tax (3)	–	–	99	0.13
Pro Forma Operating Earnings (1)	$ 1,767	$ 2.35	$ 2,605	$ 3.47

(1) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gains (losses) 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 from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. The Company's calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt . The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.

(3) For 2008, gain on sale of interests in Brazil.

(4) Per Common Share – diluted.

Reconciliation of Consolidated Net Earnings to Pro Forma Net Earnings

($ millions)		2009	2008
Net Earnings		$ 1,862	$ 5,944
Less: Cenovus Carve-out (1)		609	2,368
Add/(Deduct) Pro Forma adjustments		(504)	(171)
Pro Forma Net Earnings		749	3,405
Per share amounts			
Net Earnings	– Basic	2.48	7.92
	– Diluted	2.48	7.91
Pro Forma Net Earnings	– Basic	1.00	4.54
	– Diluted	$ 1.00	$ 4.53

(1) Cenovus Energy was spun-off on November 30, 2009. As a result, year-to-date information is for the 11 months ended November 30, 2009.

Reconciliation of Consolidated Operating Earnings to Pro Forma Operating Earnings

($ millions)		2009	2008
Operating Earnings		$ 3,495	$ 4,405
Less: Cenovus Carve-out (1)		1,224	1,629
Add/(Deduct) Pro Forma adjustments		(504)	(171)
Pro Forma Operating Earnings		1,767	2,605
Per share amounts			
Operating Earnings	– Diluted	4.65	5.86
Pro Forma Operating Earnings	– Diluted	$ 2.35	$ 3.47

(1) Cenovus Energy was spun-off on November 30, 2009. As a result, year-to-date information is for the 11 months ended November 30, 2009.

Consolidated

Summary of Cash Flow

($ millions)	2009	2008	2007
Cash From Operating Activities	$ 7,873	$ 8,986	$ 8,262
(Add back) deduct:			
Net change in other assets and liabilities	23	(257)	(10)
Net change in non-cash working capital from Continuing Operations	(29)	(1,353)	(108)
Net change in non-cash working capital from Discontinued Operations	1,100	1,210	(73)
Cash Flow	$ 6,779	$ 9,386	$ 8,453

Summary of Operating Earnings

($ millions, except per share amounts)	2009	2009 Per share (4)	2008	2008 Per share (4)	2007	2007 Per share (4)
Net Earnings, as reported	$ 1,862	$ 2.48	$ 5,944	$ 7.91	$ 3,959	$ 5.18
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax	(1,792)	(2.38)	1,818	2.42	(811)	(1.06)
Non-operating foreign exchange gain (loss), after-tax (2)	159	0.21	(378)	(0.50)	217	0.28
Gain (loss) on discontinuance, after-tax (3)	–	–	99	0.13	152	0.20
Future tax recovery due to tax rate reductions	–	–	–	–	301	0.40
Operating Earnings (1)	$ 3,495	$ 4.65	$ 4,405	$ 5.86	$ 4,100	$ 5.36

(1) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gains (losses) 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 from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. The Company's calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.

(3) For 2008, gain on sale of interests in Brazil. For 2007, gain on sale of Australia assets and interests in Chad as well as final adjustments on the NGL processing business sold in 2005.

(4) Per Common Share – diluted.

ADVISORY

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 document 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 document include, but are not limited to, statements with respect to: projected natural gas and oil production levels for 2010; projections relating to the adequacy of the Company's provision for taxes; the expected impact of the Alberta Royalty Framework and Transitional Royalty Program; projections with respect to natural gas production from unconventional resource plays; projections relating to the volatility of natural gas prices in 2010 and beyond and the reasons therefor; the Company's projected capital investment levels for 2010, the flexibility of capital spending plans and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company's operations and operating costs; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; the Company's continued compliance with financial covenants under its credit facilities; the Company's ability to pay its creditors, suppliers, commitments and fund its 2010 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the recent economic recession and financial market turmoil on the Company's operations and expected results; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards, including IFRS, on the Company and its Consolidated Financial Statements; projections that natural gas represents an abundant, secure, cleaner, long-term supply of energy to meet North American needs; projection of 70 years worth of gas supply available in North America; projected increase in production in Horn River; estimated life of Jonah field; estimated reserves and resources; expected production date of first gas in Deep Panuke; numbers of wells in developing plays and 2010 expected production per day; expected production level for 2010; estimates of additional gas supply in the following decades; expected opportunities for use of natural gas in transportation and electricity; and expected abundant supply of natural gas available at price less than the cost of other fuel. 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 reserves 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 gas reserves; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology and the application thereof to the business of the Company; 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 royalty, tax, environmental, greenhouse gas, carbon accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions 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. 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 document are made as of the date of this document, and except as required by law, 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 document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2010 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2010 of approximately 3.2 to 3.3 billion cubic feet equivalent ("Bcfe/d") per day, forward curve estimates for commodity prices and estimated U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 and an average number of outstanding shares for EnCana of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana's news release dated February 11, 2010, which is available on EnCana's website at www.encana.com and on SEDAR at www.sedar.com.

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 that 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 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.

Reserves Reporting Protocols

Under the amended SEC rules, EnCana's 2009 proved reserves have been determined based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For 2009, this resulted in a Henry Hub natural gas price of $3.87 per MMBtu, compared to a December 31st single-day price of $5.71 per MMBtu for 2008 reporting purposes. Because EnCana does not use prices derived for SEC reporting purposes in the day-to-day operation of its business or for planning purposes, it has highlighted 2009 reserves information in this document as "before SEC price revisions" attributable to the changes in natural gas pricing assumptions, which EnCana believes is a better reflection of its annual reserves additions performance. For all "before SEC price revisions" reserves estimates highlighted in this document, EnCana has used Henry Hub forecast prices of $5.50 per MMBtu for 2010 and $6.50 per MMBtu for 2011 and beyond. EnCana's 2009 net proved reserves information as defined under SEC disclosure protocols will be disclosed in the Company's Annual Information Form in February 2010. This disclosure will reflect the SEC average price and changes due to the Company's Split Transaction.

Natural Gas, Crude Oil and NGLs Conversions

In this document, certain crude oil and 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 well head.

Resource Play

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.

Currency, Pro Forma Information, Non-GAAP Measures and References to EnCana

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Pro Forma Information

On November 30, 2009, EnCana completed a major corporate reorganization – a Split Transaction that resulted in the Company's transition into a pure-play natural gas company and the spin off of its Integrated Oil and Canadian Plains assets into Cenovus Energy Inc., an independent, publicly traded energy company. EnCana's consolidated results include the financial and operating performance of the Cenovus assets for the first 11 months of 2009 and are reflected in EnCana's consolidated fourth quarter and 2009 financial statements. To give investors a clear understanding of post-split EnCana, fourth quarter and 2009 financial and operating results in this document highlight EnCana's results on a pro forma basis, which reflect the Company as if the Split Transaction had been completed for all of 2009 and the previous years presented. In this pro forma presentation, the results associated with the assets and operations transferred to Cenovus are eliminated from EnCana's consolidated results, and adjustments specific to the Split Transaction are reflected.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings per share – diluted, Adjusted EBITDA, Debt, Net Debt and Capitalization 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 document 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 document as these measures are discussed and presented.

References to EnCana

For convenience, references in this document to "EnCana", the "Company", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

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 the NYSE corporate governance standards. A summary of these significant differences is available on EnCana's website (www.encana.com). Except as described in this document, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

Additional Information

Further information regarding EnCana Corporation, including its Annual Information Form, can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at www.encana.com.

MANAGEMENT REPORT

Management's Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of EnCana Corporation (the "Company") are the responsibility of Management. The Consolidated 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.

The Company's Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfils 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.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of the Company's internal control over financial reporting as at December 31, 2009. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting. Based on our evaluation, Management has concluded that the Company's internal control over financial reporting was effectively designed and operating effectively as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2009, as stated in their Auditors' Report. PricewaterhouseCoopers LLP has provided such opinions.

Sherri Brillon

Randall K. Eresman
President & Chief Executive Officer

Sherri A. Brillon
Executive Vice-President & Chief Financial Officer

February 17, 2010

AUDITORS' REPORT

To the Shareholders of EnCana Corporation

We have completed integrated audits of EnCana Corporation's 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnCana Corporation as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, shareholders' equity, comprehensive income and cash flows for each of the years in the three year period ended December 31, 2009. 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 of the Company's financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal Control Over Financial Reporting

We have also audited EnCana Corporation's internal control over financial reporting as at December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in *Internal Control – Integrated Framework* issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 17, 2010

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended December 31 (US$ millions, except per share amounts)		2009	2008	2007
Revenues, Net of Royalties	*(Note 4)*	**$ 11,114**	$ 21,053	$ 14,385
Expenses	*(Note 4)*			
Production and mineral taxes		**171**	478	291
Transportation and selling		**1,280**	1,704	1,264
Operating		**1,627**	1,983	1,850
Purchased product		**1,460**	2,426	2,770
Depreciation, depletion and amortization		**3,704**	4,035	3,657
Administrative		**477**	447	356
Interest, net	*(Note 8)*	**405**	402	234
Accretion of asset retirement obligation	*(Note 16)*	**71**	77	63
Foreign exchange (gain) loss, net	*(Note 9)*	**(22)**	423	(164)
(Gain) loss on divestitures	*(Note 7)*	**2**	(141)	(65)
		9,175	11,834	10,256
Net Earnings Before Income Tax		**1,939**	9,219	4,129
Income tax expense	*(Note 10)*	**109**	2,720	682
Net Earnings From Continuing Operations		**1,830**	6,499	3,447
Net Earnings (Loss) From Discontinued Operations	*(Note 6)*	**32**	(555)	512
Net Earnings		**$ 1,862**	$ 5,944	$ 3,959
Net Earnings From Continuing Operations per Common Share	*(Note 17)*			
Basic		**$ 2.44**	$ 8.66	$ 4.55
Diluted		**$ 2.44**	$ 8.64	$ 4.51
Net Earnings per Common Share	*(Note 17)*			
Basic		**$ 2.48**	$ 7.92	$ 5.23
Diluted		**$ 2.48**	$ 7.91	$ 5.18

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the years ended December 31 (US$ millions)	2009	2008	2007
Net Earnings	**$ 1,862**	$ 5,944	$ 3,959
Other Comprehensive Income, Net of Tax			
Foreign Currency Translation Adjustment	**2,018**	(2,230)	1,688
Comprehensive Income	**$ 3,880**	$ 3,714	$ 5,647

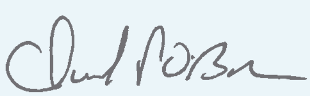
See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET

As at December 31 (US$ millions)		2009	2008
Assets			
Current Assets			
Cash and cash equivalents		$ 4,275	$ 354
Accounts receivable and accrued revenues		1,180	1,436
Current portion of partnership contribution receivable	*(Notes 5, 11)*	–	313
Risk management	*(Note 20)*	328	2,818
Inventories	*(Note 12)*	12	184
Assets of discontinued operations	*(Note 6)*	–	497
		5,795	5,602
Property, Plant and Equipment, net	*(Notes 4, 13)*	26,173	31,910
Investments and Other Assets	*(Note 14)*	164	72
Partnership Contribution Receivable	*(Notes 5, 11)*	–	2,834
Risk Management	*(Note 20)*	32	234
Goodwill	*(Note 4)*	1,663	2,426
Assets of Discontinued Operations	*(Note 6)*	–	4,169
	(Note 4)	$ 33,827	$ 47,247
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,143	$ 2,448
Income tax payable		1,776	500
Risk management	*(Note 20)*	126	43
Current portion of long-term debt	*(Note 15)*	200	250
Liabilities of discontinued operations	*(Note 6)*	–	653
		4,245	3,894
Long-Term Debt	*(Note 15)*	7,568	8,755
Other Liabilities	*(Note 4)*	1,185	576
Risk Management	*(Note 20)*	42	7
Asset Retirement Obligation	*(Note 16)*	787	1,230
Future Income Taxes	*(Note 10)*	3,386	6,917
Liabilities of Discontinued Operations	*(Note 6)*	–	2,894
		17,213	24,273
Commitments and Contingencies	*(Note 22)*		
Shareholders' Equity			
Share capital	*(Note 17)*	2,360	4,557
Paid in surplus	*(Note 17)*	6	–
Retained earnings		13,493	17,584
Accumulated other comprehensive income		755	833
Total Shareholders' Equity		16,614	22,974
		$ 33,827	$ 47,247

See accompanying Notes to Consolidated Financial Statements

Approved by the Board



David P. O'Brien
Director

Jane L. Peverett
Director

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

For the years ended December 31 (US$ millions)		2009	2008	2007
Share Capital				
Balance, Beginning of Year		$ 4,557	$ 4,479	$ 4,587
Common Shares Issued under Option Plans	*(Note 17)*	5	80	176
Common Shares Issued from PSU Trust	*(Note 17)*	19	–	–
Stock-Based Compensation	*(Note 17)*	1	11	17
Common Shares Purchased	*(Note 17)*	–	(13)	(301)
Common Shares Cancelled	*(Note 3)*	(4,582)	–	–
New EnCana Common Shares Issued	*(Note 3)*	2,360	–	–
EnCana Special Shares Issued	*(Note 3)*	2,222	–	–
EnCana Special Shares Cancelled	*(Note 3)*	(2,222)	–	–
Balance, End of Year		$ 2,360	$ 4,557	$ 4,479
Paid in Surplus				
Balance, Beginning of Year		$ –	$ 80	$ 160
Common Shares Issued from PSU Trust	*(Note 17)*	6	–	–
Stock-Based Compensation		–	1	43
Common Shares Distributed under Incentive Compensation Plans		–	(81)	(123)
Balance, End of Year		$ 6	$ –	$ 80
Retained Earnings				
Balance, Beginning of Year		$ 17,584	$ 13,082	$ 11,344
Net Earnings		1,862	5,944	3,959
Dividends on Common Shares		(1,051)	(1,199)	(603)
Charges for Normal Course Issuer Bid	*(Note 17)*	–	(243)	(1,618)
Net Distribution to Cenovus Energy	*(Note 3)*	(4,902)	–	–
Balance, End of Year		$ 13,493	$ 17,584	$ 13,082
Accumulated Other Comprehensive Income				
Balance, Beginning of Year		$ 833	$ 3,063	$ 1,375
Foreign Currency Translation		2,018	(2,230)	1,688
Transferred to Cenovus Energy	*(Note 3)*	(2,096)	–	–
Balance, End of Year		$ 755	$ 833	$ 3,063
Total Shareholders' Equity		$ 16,614	$ 22,974	$ 20,704

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31 (US$ millions)		2009	2008	2007
Operating Activities				
Net earnings from continuing operations		$ 1,830	$ 6,499	$ 3,447
Depreciation, depletion and amortization		3,704	4,035	3,657
Future income taxes	*(Note 10)*	(1,799)	1,723	(698)
Cash tax on sale of assets	*(Note 10)*	–	25	–
Unrealized (gain) loss on risk management	*(Note 20)*	2,680	(2,729)	1,235
Unrealized foreign exchange (gain) loss		(231)	417	41
Accretion of asset retirement obligation	*(Note 16)*	71	77	63
(Gain) loss on divestitures	*(Note 7)*	2	(141)	(65)
Other		373	(79)	95
Cash flow from discontinued operations		149	(441)	678
Net change in other assets and liabilities		23	(257)	(10)
Net change in non-cash working capital from continuing operations	*(Note 21)*	(29)	(1,353)	(108)
Net change in non-cash working capital from discontinued operations		1,100	1,210	(73)
Cash From Operating Activities		7,873	8,986	8,262
Investing Activities				
Capital expenditures	*(Note 4)*	(4,864)	(7,997)	(8,438)
Proceeds from divestitures	*(Note 7)*	1,178	904	481
Cash tax on sale of assets	*(Note 10)*	–	(25)	–
Corporate acquisitions		(24)	–	–
Cash transferred on Split Transaction	*(Note 3)*	(3,996)	–	–
Proceeds from notes receivable from Cenovus	*(Note 3)*	3,750	–	–
Net change in investments and other		337	311	331
Net change in non-cash working capital from continuing operations	*(Note 21)*	(50)	34	51
Discontinued operations		(1,137)	(769)	(604)
Cash (Used in) Investing Activities		(4,806)	(7,542)	(8,179)
Financing Activities				
Net issuance (repayment) of revolving long-term debt		(1,852)	(53)	181
Issuance of long-term debt	*(Note 15)*	496	723	2,409
Issuance of Cenovus Notes	*(Note 3)*	3,468	–	–
Repayment of long-term debt	*(Note 15)*	(250)	(664)	(257)
Issuance of common shares	*(Note 17)*	24	80	176
Purchase of common shares	*(Note 17)*	–	(326)	(2,025)
Dividends on common shares		(1,051)	(1,199)	(603)
Cash From (Used in) Financing Activities		835	(1,439)	(119)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		19	(33)	16
Increase (Decrease) in Cash and Cash Equivalents		3,921	(28)	(20)
Cash and Cash Equivalents, Beginning of Year		354	382	402
Cash and Cash Equivalents, End of Year		$ 4,275	$ 354	$ 382
Cash (Bank Overdraft), End of Year		$ 218	$ 13	$ (19)
Cash Equivalents, End of Year		4,057	341	401
Cash and Cash Equivalents, End of Year		$ 4,275	$ 354	$ 382

Supplementary Cash Flow Information *(Note 21)*

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, 2009

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's functional currency is Canadian 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 oil and gas companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana's continuing operations are in the business of the exploration for, the development of, and the production and marketing of natural gas, crude oil and natural gas liquids ("NGLs").

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 ("GAAP"). Information prepared in accordance with GAAP in the United States is included in Note 23.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana's exploration, development and production 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.

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 in Accumulated Other Comprehensive Income ("AOCI") as a separate component of Shareholders' Equity. As at December 31, 2009, AOCI solely includes foreign currency translation adjustments.

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 GAAP 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, costs and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact in the Consolidated Financial Statements of future periods could be material.

The estimated fair value of derivative instruments resulting in financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

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

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

D) REVENUE RECOGNITION

Revenues associated with the sales of EnCana's natural gas, crude oil, NGLs and petroleum and chemical products are recognized when title passes from the Company to its customer. Realized gains and losses from the Company's natural gas and crude oil 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. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as 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 natural gas and crude oil 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, including diluent, 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 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 accrued benefit obligation is discounted using the market interest rate on high-quality corporate debt instruments as at the measurement date.

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. Amortization is done on a straight-line basis over a period covering 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 net earnings in the period that the change occurs.

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 common 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 cost and net realizable value on a first-in, first-out or weighted average cost basis.

L) PROPERTY, PLANT AND EQUIPMENT

UPSTREAM

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' ("CICA") 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, the 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 depleted 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 divestiture 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 depletion 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 the 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 depletion.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable. 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 measured as 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.

DOWNSTREAM REFINING (DISCONTINUED)

The initial acquisition costs of refinery property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over their estimated service lives of approximately 25 years.

An impairment loss is recognized on refinery property, plant and equipment when the carrying amount is not recoverable. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the fair value.

MARKET OPTIMIZATION

Midstream facilities, including 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 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 three to 25 years. Assets under construction are not subject to depreciation until put into use. 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

Items included in Investments and Other Assets are amortized, 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 as at December 31 of each year. Goodwill and all other assets and liabilities have been allocated to the country cost centre levels, 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 incurred 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. 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.

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

Obligations for payments, cash or common shares under EnCana's share appreciation rights, stock options with tandem share appreciation rights attached, deferred share and performance share units plans are accrued as compensation expense over the vesting period using the intrinsic value method.

Obligations for payments for share options of Cenovus Energy Inc. ("Cenovus") held by EnCana employees are accrued as compensation expense based on the fair value of the financial liability.

Fluctuations in the underlying common share prices change the accrued compensation cost and are recognized when they occur.

R) FINANCIAL INSTRUMENTS

Financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the accounting standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents, accounts receivable and accounts payable relating to share options of EnCana held by Cenovus employees, and accounts payable for share options of Cenovus held by EnCana employees are designated as "held-for-trading" and are measured at fair value.

With the exception of accounts receivable relating to share options of EnCana held by Cenovus employees, accounts receivable and accrued revenues and the partnership contribution receivable are designated as "loans and receivables".

With the exception of accounts payable relating to share options of EnCana held by Cenovus employees and accounts payable relating to share options of Cenovus held by EnCana employees, accounts payable and accrued liabilities and long-term debt are designated as "other financial liabilities".

EnCana capitalizes long-term debt transaction costs, premiums and discounts. These costs are capitalized within long-term debt and amortized using the effective interest method.

RISK MANAGEMENT ASSETS AND LIABILITIES

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded at fair value 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 natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized 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

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. The impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

As of January 1, 2011, EnCana will be required to adopt the following CICA Handbook sections:

- "Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.
- "Consolidated Financial Statements", Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- "Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

T) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2009, the Company adopted the following CICA Handbook section:

- "Goodwill and Intangible Assets", Section 3064. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements.

3. SPLIT TRANSACTION

On November 30, 2009, EnCana completed a corporate reorganization (the "Split Transaction") involving the division of EnCana into two independent publicly traded energy companies – one, EnCana Corporation, a natural gas company, and the other, an integrated oil company, Cenovus Energy Inc.

The Split Transaction was initially proposed in May 2008. In October 2008, EnCana announced the proposed reorganization would be delayed until the global debt and equity markets regained stability. In September 2009, EnCana's Board of Directors unanimously approved plans to proceed with the split and in November 2009, shareholders approved to proceed with the Split Transaction.

Under the Split Transaction, EnCana shareholders received one new EnCana Common Share and one EnCana Special Share in exchange for each EnCana Common Share previously held. The book value of EnCana's outstanding Common Shares immediately prior to the Split Transaction was attributed to the new EnCana Common Shares and the EnCana Special Shares in direct proportion to the weighted average trading price of the shares on a "when issued" basis. In accordance with the calculation, the value attributed to the new EnCana Common Shares and the EnCana Special Shares was $2,360 million and $2,222 million, respectively. The EnCana Special Shares were subsequently exchanged by EnCana shareholders for Common Shares of Cenovus, thereby effecting the Split Transaction.

Under the Split Transaction, EnCana's downstream refining operations and certain upstream oil and gas assets were transferred to Cenovus. The historical results associated with the upstream assets transferred are reported as continuing operations in accordance with full cost accounting requirements (See Note 4). The historical results associated with the downstream refining operations have been presented as discontinued operations (See Note 6).

In conjunction with the proposed reorganization, on September 18, 2009, Cenovus completed a private offering of senior unsecured notes for an aggregate principal amount of $3,500 million. The unsecured notes ("Cenovus Notes") were transferred under the Split Transaction.

The impact of the Split Transaction on EnCana's Consolidated Balance Sheet is as follows. The net assets were transferred at book value.

Net Assets Transferred Under the Split Transaction

Assets	
Cash and restricted cash	$ 3,996
Property, plant and equipment, net	
Oil and gas	9,329
Downstream refining (See Note 6)	4,710
Partnership contribution receivable, including current portion	2,835
Goodwill	1,083
Other current and non-current assets	2,094
	24,047
Liabilities	
Notes payable to EnCana	3,750
Cenovus notes	3,436
Partnership contribution payable, including current portion	2,857
Future income taxes	2,314
Other current and non-current liabilities	2,470
	14,827
Net Assets Transferred Under the Split Transaction	$ 9,220

The Split Transaction reduced Total Shareholders' Equity by way of a reduction in Share capital of $2,222 million, a reduction in Retained earnings of $4,902 million and a reduction in Accumulated other comprehensive income of $2,096 million.

Following the Split Transaction, EnCana received amounts due from Cenovus and invested the net proceeds of approximately $3.75 billion in short-term marketable securities.

EnCana's continuing operations include all revenues and expenses prior to November 30, 2009 of the oil and gas assets transferred to Cenovus under the Split Transaction (See Note 4).

4. SEGMENTED INFORMATION

The Company's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization markets substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

In conjunction with the Split Transaction (See Note 3), the assets formerly included in EnCana's Canadian Plains Division and Integrated Oil Division were transferred to Cenovus. As a result, EnCana has updated its segmented reporting to present the Canadian Foothills Division as the Canadian Division. The Canadian Plains Division and Integrated Oil – Canada are now presented as Canada – Other. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision-making and reporting structure. Accordingly, the Company reports its divisional results as follows:

- **Canadian Division,** formerly the Canadian Foothills Division, includes natural gas development and production assets located in British Columbia and Alberta, as well as the Company's Canadian offshore assets.
- **USA Division** includes natural gas exploration, development and production assets located in the United States and forms the USA segment described above.
- **Canada – Other** includes the combined results from the former Canadian Plains Division and Integrated Oil – Canada.

Operations that have been discontinued are disclosed in Note 6.

RESULTS OF CONTINUING OPERATIONS

Segment and Geographic Information

For the years ended December 31	Canada 2009	Canada 2008	Canada 2007	USA 2009	USA 2008	USA 2007	Market Optimization 2009	Market Optimization 2008	Market Optimization 2007
Revenues, Net of Royalties	$ 7,585	$ 10,050	$ 8,308	$ 4,537	$ 5,629	$ 4,372	$ 1,607	$ 2,655	$ 2,944
Expenses									
Production and mineral taxes	53	108	102	118	370	189	–	–	–
Transportation and selling	750	1,202	947	530	502	307	–	–	10
Operating	1,118	1,333	1,204	434	618	595	26	45	37
Purchased product	(85)	(151)	(88)	–	–	–	1,545	2,577	2,858
	5,749	7,558	6,143	3,455	4,139	3,281	36	33	39
Depreciation, depletion and amortization	1,980	2,198	2,298	1,561	1,691	1,181	20	15	17
Segment Income (Loss)	$ 3,769	$ 5,360	$ 3,845	$ 1,894	$ 2,448	$ 2,100	$ 16	$ 18	$ 22

	Corporate & Other 2009	Corporate & Other 2008	Corporate & Other 2007	Consolidated 2009	Consolidated 2008	Consolidated 2007
Revenues, Net of Royalties	$ (2,615)	$ 2,719	$ (1,239)	$ 11,114	$ 21,053	$ 14,385
Expenses						
Production and mineral taxes	–	–	–	171	478	291
Transportation and selling	–	–	–	1,280	1,704	1,264
Operating	49	(13)	14	1,627	1,983	1,850
Purchased product	–	–	–	1,460	2,426	2,770
	(2,664)	2,732	(1,253)	6,576	14,462	8,210
Depreciation, depletion and amortization	143	131	161	3,704	4,035	3,657
Segment Income (Loss)	$ (2,807)	$ 2,601	$ (1,414)	2,872	10,427	4,553
Administrative				477	447	356
Interest, net				405	402	234
Accretion of asset retirement obligation				71	77	63
Foreign exchange (gain) loss, net				(22)	423	(164)
(Gain) loss on divestitures				2	(141)	(65)
				933	1,208	424
Net Earnings Before Income Tax				1,939	9,219	4,129
Income tax expense				109	2,720	682
Net Earnings From Continuing Operations				$ 1,830	$ 6,499	$ 3,447

RESULTS OF CONTINUING OPERATIONS

Product and Divisional Information

	Canada Segment								
	Canadian Division			Canada – Other			Total		
For the years ended December 31	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**$ 3,362**	$ 4,355	$ 3,679	**$ 4,223**	$ 5,695	$ 4,629	**$ 7,585**	$ 10,050	$ 8,308
Expenses									
Production and mineral taxes	**14**	33	39	**39**	75	63	**53**	108	102
Transportation and selling	**154**	239	201	**596**	963	746	**750**	1,202	947
Operating	**536**	609	535	**582**	724	669	**1,118**	1,333	1,204
Purchased product	**–**	–	–	**(85)**	(151)	(88)	**(85)**	(151)	(88)
Operating Cash Flow	**$ 2,658**	$ 3,474	$ 2,904	**$ 3,091**	$ 4,084	$ 3,239	**$ 5,749**	$ 7,558	$ 6,143

	Canadian Division*								
	Gas			Oil & NGLs			Other		
For the years ended December 31	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**$ 3,041**	$ 3,720	$ 3,232	**$ 277**	$ 578	$ 390	**$ 44**	$ 57	$ 57
Expenses									
Production and mineral taxes	**11**	28	36	**3**	5	3	**–**	–	–
Transportation and selling	**148**	201	192	**6**	12	9	**–**	26	–
Operating	**501**	549	482	**21**	39	33	**14**	21	20
Operating Cash Flow	**$ 2,381**	$ 2,942	$ 2,522	**$ 247**	$ 522	$ 345	**$ 30**	$ 10	$ 37

	Total		
	2009	2008	2007
Revenues, Net of Royalties	**$ 3,362**	$ 4,355	$ 3,679
Expenses			
Production and mineral taxes	**14**	33	39
Transportation and selling	**154**	239	201
Operating	**536**	609	535
Operating Cash Flow	**$ 2,658**	$ 3,474	$ 2,904

* Formerly known as the Canadian Foothills Division.

RESULTS OF CONTINUING OPERATIONS

Product and Divisional Information

	USA Division								
	Gas			Oil & NGLs			Other		
For the years ended December 31	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**$ 4,222**	$ 4,934	$ 3,765	**$ 201**	$ 407	$ 309	**$ 114**	$ 288	$ 298
Expenses									
Production and mineral taxes	**100**	334	167	**18**	36	22	**–**	–	–
Transportation and selling	**530**	502	307	**–**	–	–	**–**	–	–
Operating	**327**	352	323	**–**	–	–	**107**	266	272
Operating Cash Flow	**$ 3,265**	$ 3,746	$ 2,968	**$ 183**	$ 371	$ 287	**$ 7**	$ 22	$ 26

	Total		
	2009	2008	2007
Revenues, Net of Royalties	**$ 4,537**	$ 5,629	$ 4,372
Expenses			
Production and mineral taxes	**118**	370	189
Transportation and selling	**530**	502	307
Operating	**434**	618	595
Operating Cash Flow	**$ 3,455**	$ 4,139	$ 3,281

	Canada – Other**								
	Gas			Oil & NGLs			Other		
For the years ended December 31	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**$ 1,781**	$ 2,301	$ 2,186	**$ 2,287**	$ 3,223	$ 2,191	**$ 155**	$ 171	$ 252
Expenses									
Production and mineral taxes	**15**	36	34	**23**	38	29	**1**	1	–
Transportation and selling	**37**	71	82	**535**	847	629	**24**	45	35
Operating	**186**	241	221	**356**	409	374	**40**	74	74
Purchased product	**–**	–	–	**–**	–	–	**(85)**	(151)	(88)
Operating Cash Flow	**$ 1,543**	$ 1,953	$ 1,849	**$ 1,373**	$ 1,929	$ 1,159	**$ 175**	$ 202	$ 231

	Total		
	2009	2008	2007
Revenues, Net of Royalties	**$ 4,223**	$ 5,695	$ 4,629
Expenses			
Production and mineral taxes	**39**	75	63
Transportation and selling	**596**	963	746
Operating	**582**	724	669
Purchased product	**(85)**	(151)	(88)
Operating Cash Flow	**$ 3,091**	$ 4,084	$ 3,239

** Includes the operations formerly known as the Canadian Plains Division and Integrated Oil – Canada.

Capital Expenditures (Continuing Operations)

For the years ended December 31	2009	2008	2007
Capital			
Canadian Division	$ 1,869	$ 2,459	$ 2,403
Canada – Other	848	1,500	1,238
Canada	2,717	3,959	3,641
USA	1,821	2,682	1,935
Market Optimization	2	17	6
Corporate & Other	85	165	154
	4,625	6,823	5,736
Acquisition Capital			
Canadian Division	190	151	75
Canada – Other	3	–	14
Canada	193	151	89
USA	46	1,023	2,613
	239	1,174	2,702
Total	$ 4,864	$ 7,997	$ 8,438

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Haynesville represented an interest in a Variable Interest Entity ("VIE") from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest was completed, the assets were transferred to EnCana.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

Additions to Goodwill

There were no additions to goodwill during 2009 or 2008.

As a result of the Split Transaction, a portion of goodwill was transferred to Cenovus (See Note 3).

Property, Plant and Equipment and Total Assets by Segment

		Property, Plant and Equipment		Total Assets	
As at December 31		**2009**	2008	**2009**	2008
Canada		**$ 11,162**	$ 17,498	**$ 12,748**	$ 23,419
USA		**13,929**	13,643	**14,962**	14,635
Market Optimization		**124**	140	**303**	429
Corporate & Other		**958**	629	**5,814**	4,098
Assets of Discontinued Operations	*(Note 6)*			**–**	4,666
Total		**$ 26,173**	$ 31,910	**$ 33,827**	$ 47,247

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. As at December 31, 2009, Canada Property, Plant and Equipment and Total Assets include EnCana's accrual to date of $427 million (2008 – $199 million) related to this offshore facility as an asset under construction.

On February 9, 2007, EnCana announced that it had entered into a 25-year lease agreement with a third party developer for The Bow office project. As at December 31, 2009, Corporate and Other Property, Plant and Equipment and Total Assets include EnCana's accrual to date of $649 million (2008 – $252 million) related to this office project as an asset under construction.

For further information relating to The Bow office project, refer to Note 22.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

Goodwill, Property, Plant and Equipment and Total Assets by Geographic Region

	Goodwill		Property, Plant and Equipment		Total Assets	
As at December 31	**2009**	2008	**2009**	2008	**2009**	2008
Canada	**$ 1,190**	$ 1,953	**$ 12,181**	$ 18,206	**$ 18,682**	$ 27,726
United States	**473**	473	**13,982**	13,694	**15,099**	19,414
Other Countries	**–**	–	**10**	10	**46**	107
Total	**$ 1,663**	$ 2,426	**$ 26,173**	$ 31,910	**$ 33,827**	$ 47,247

Export Sales

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were $757 million (2008 – $1,874 million; 2007 – $1,362 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, 2009, the Company had one customer (2008 – one; 2007 – two) which individually accounted for more than 10 percent of EnCana's consolidated revenues, net of royalties. Sales to this customer, which has a high quality investment grade credit rating, were approximately $1,755 million (2008 – $2,413 million; 2007 – $3,461 million).

5. JOINT VENTURE WITH CONOCOPHILLIPS

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consisted of an upstream and a downstream entity. The upstream entity contribution included assets from EnCana, primarily the Foster Creek and Christina Lake properties, with a fair value of $7.5 billion and a note receivable contributed from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of $7.5 billion, and EnCana contributed a note payable of $7.5 billion.

The joint venture arrangement with ConocoPhillips was transferred to Cenovus as part of the Split Transaction (See Note 3). The downstream operations have been disclosed as discontinued operations (See Note 6).

6. DISCONTINUED OPERATIONS

DOWNSTREAM REFINING

As a result of the Split Transaction described in Note 3, EnCana transferred its downstream refining operations to Cenovus. Downstream refining focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. These refineries were jointly owned with ConocoPhillips.

MIDSTREAM

The $75 million gain on discontinuance in 2007 is the result of an expired clause included in the December 2005 sale of the Company's Midstream natural gas liquids processing operations. The clause provided potential market price support for the facilities and was accrued for in 2005.

CONSOLIDATED STATEMENT OF EARNINGS

The following table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	Downstream Refining			Midstream	Consolidated Total		
For the years ended December 31	**2009**	2008	2007	2007	**2009**	2008	2007
Revenues, Net of Royalties	**$ 4,804**	$ 9,011	$ 7,315	$ –	**$ 4,804**	$ 9,011	$ 7,315
Expenses							
Operating	**416**	492	428	–	**416**	492	428
Purchased product	**4,070**	8,760	5,813	–	**4,070**	8,760	5,813
Depreciation, depletion and amortization	**173**	188	159	–	**173**	188	159
Administrative	**44**	26	28	–	**44**	26	28
Interest, net	**163**	184	194	–	**163**	184	194
Accretion of asset retirement obligation	**2**	2	1	–	**2**	2	1
Foreign exchange (gain) loss, net	**1**	–	–	–	**1**	–	–
(Gain) loss on divestitures	**–**	1	–	(75)	**–**	1	(75)
	4,869	9,653	6,623	(75)	**4,869**	9,653	6,548
Net Earnings (Loss) Before Income Tax	**(65)**	(642)	692	75	**(65)**	(642)	767
Income tax expense (recovery)	**(97)**	(87)	255	–	**(97)**	(87)	255
Net Earnings (Loss) From Discontinued Operations	**$ 32**	$ (555)	$ 437	$ 75	**$ 32**	$ (555)	$ 512
Net Earnings (Loss) From Discontinued Operations per Common Share							
Basic					**$ 0.04**	$ (0.74)	$ 0.68
Diluted					**$ 0.04**	$ (0.73)	$ 0.67

CONSOLIDATED BALANCE SHEET

The following table presents the effect of the discontinued operations in the Consolidated Balance Sheet:

As at December 31	2009	2008
Assets		
Current Assets		
Cash and cash equivalents	$ –	$ 29
Accounts receivable and accrued revenues	–	132
Inventories	–	336
	–	497
Property, Plant and Equipment, net	–	4,032
Investments and Other Assets	–	137
	$ –	$ 4,666
Liabilities		
Current Liabilities		
Accounts payable and accrued liabilities	$ –	$ 423
Income tax payable	–	(76)
Current portion of partnership contribution payable	–	306
	–	653
Partnership Contribution Payable	–	2,857
Asset Retirement Obligation	–	35
Future Income Taxes	–	2
	–	3,547
Net Assets of Discontinued Operations	$ –	$ 1,119

7. ACQUISITIONS AND DIVESTITURES

ACQUISITIONS

On May 5, 2009, the Company acquired the common shares of Kerogen Resources Canada, ULC for net cash consideration of $24 million. The acquisition included $37 million of property, plant and equipment and the assumption of $6 million of current liabilities and $7 million of future income taxes. The operations are included in the Canadian Division.

DIVESTITURES

For the years ended December 31	2009	2008	2007
Canadian Division	$ 1,000	$ 400	$ 213
Canada – Other	17	47	–
Canada	1,017	447	213
USA	73	251	10
Corporate & Other	88	206	258
	$ 1,178	$ 904	$ 481

Proceeds received on the sale of assets and investments in 2009 were $1,178 million (2008 – $904 million; 2007 – $481 million). The significant items are described below.

Canada

In 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $1,000 million (2008 – $400 million; 2007 – $213 million) in the Canadian Division and $17 million (2008 – $47 million; 2007 – nil) in Canada – Other.

In May 2007, the Company completed the sale of its assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million, which were credited to property, plant and equipment in the Canadian cost centre and reported in the Canadian Division.

USA

In 2009, the Company completed the divestiture of mature conventional natural gas assets for proceeds of $73 million (2008 – $251 million; 2007 – $10 million).

Corporate and Other

On November 3, 2009, the Company completed the sale of Senlac Oil Limited for cash consideration of $83 million.

In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million, before closing adjustments, resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

In August 2007, the Company closed the sale of Australia assets for proceeds of $31 million resulting in a gain on sale of $30 million. After recording income tax of $5 million, EnCana recorded an after-tax gain of $25 million.

In February 2007, the Company sold The Bow office project assets for proceeds of approximately $57 million, largely representing its investment at the date of sale. Refer to Note 4 for further discussion of The Bow office project assets.

In January 2007, the Company completed the sale of its interests in Chad – properties that were in the pre-production stage – for proceeds of $208 million which resulted in a gain on sale of $59 million.

8. INTEREST, NET

For the years ended December 31	2009	2008	2007
Interest Expense – Long-Term Debt	$ 533	$ 556	$ 460
Interest Expense – Other	40	49	32
Interest Income*	(168)	(203)	(258)
	$ 405	$ 402	$ 234

* Interest Income is primarily due to the Partnership Contribution Receivable, which was transferred to Cenovus under the Split Transaction (See Notes 3 and 11).

9. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31	2009	2008	2007
Unrealized Foreign Exchange (Gain) Loss on:			
Translation of U.S. dollar debt issued from Canada	$ (978)	$ 1,033	$ (683)
Translation of U.S. dollar partnership contribution receivable issued from Canada*	448	(608)	617
Other Foreign Exchange (Gain) Loss on:			
Monetary revaluations and settlements	508	(2)	(98)
	$ (22)	$ 423	$ (164)

* The Partnership Contribution Receivable was transferred to Cenovus under the Split Transaction (See Notes 3 and 11).

10. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31	2009	2008	2007
Current			
Canada	$ 1,623	$ 547	$ 900
United States	279	407	473
Other Countries	6	43	7
Total Current Tax	1,908	997	1,380
Future	(1,799)	1,723	(397)
Future Tax Rate Reductions	–	–	(301)
Total Future Tax	(1,799)	1,723	(698)
	$ 109	$ 2,720	$ 682

Included in current tax for 2008 is $25 million related to the sale of assets in Brazil (2009 – nil; 2007 – nil).

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

For the years ended December 31	2009	2008	2007
Net Earnings Before Income Tax	$ 1,939	$ 9,219	$ 4,129
Canadian Statutory Rate	29.2%	29.7%	32.3%
Expected Income Tax	566	2,734	1,334
Effect on Taxes Resulting from:			
Statutory and other rate differences	(199)	167	41
Effect of tax rate changes	–	–	(301)
Effect of legislative changes	–	–	(179)
International financing	(101)	(268)	(62)
Foreign exchange (gains) losses not included in net earnings	20	47	–
Non-taxable capital (gains) losses	(71)	84	(124)
Other	(106)	(44)	(27)
	$ 109	$ 2,720	$ 682
Effective Tax Rate	5.6%	29.5%	16.5%

The net future income tax liability consists of:

As at December 31	2009	2008
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	$ 3,420	$ 5,366
Timing of partnership items	78	924
Risk management	75	955
Future Tax Assets		
Non-capital and net capital losses carried forward	(174)	(46)
Other	(13)	(282)
Net Future Income Tax Liability	$ 3,386	$ 6,917

The approximate amounts of tax pools available are as follows:

As at December 31	2009	2008
Canada	$ 7,393	$ 9,029
United States	7,098	7,146
	$ 14,491	$ 16,175

Included in the above tax pools are $691 million (2008 – $184 million) related to non-capital and net capital losses available for carry forward to reduce taxable income in future years. The non-capital losses expire between 2010 and 2029.

11. PARTNERSHIP CONTRIBUTION RECEIVABLE

On January 2, 2007, upon the creation of the Integrated Oil joint venture, ConocoPhillips entered into a subscription agreement for a 50 percent interest in the upstream entity in exchange for a promissory note of $7.5 billion. The note bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term portions of the partnership contribution receivable shown in the 2008 Consolidated Balance Sheet represent EnCana's 50 percent share of this promissory note, net of payments to date. In conjunction with the Split Transaction, the current and long-term portions of the partnership contribution receivable were transferred to Cenovus (See Note 3).

12. INVENTORIES

As at December 31	2009	2008
Product		
Canada	$ 4	$ 46
USA	6	8
Market Optimization	2	127
Parts and Supplies	–	3
	$ 12	$ 184

At December 31, 2009, there was no inventory impairment. As a result of a significant decline in commodity prices in the latter half of 2008, EnCana wrote down its product inventory by $57 million from cost to net realizable value. As at December 31, 2009, $47 million of the 2008 write down was reversed.

The total amount of inventories recognized as an expense during the year was $24 million (2008 – $140 million).

13. PROPERTY, PLANT AND EQUIPMENT, NET

As at December 31	2009			2008		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Canada	$ 22,872	$ (11,710)	$ 11,162	$ 34,905	$ (17,407)	$ 17,498
USA	21,021	(7,092)	13,929	19,154	(5,511)	13,643
Market Optimization	214	(90)	124	220	(80)	140
Corporate & Other	1,396	(438)	958	1,245	(616)	629
	$ 45,503	$ (19,330)	$ 26,173	$ 55,524	$ (23,614)	$ 31,910

* Depreciation, depletion and amortization.

Canada and USA property, plant and equipment include internal costs directly related to exploration, development and construction activities of $383 million (2008 – $378 million). Costs classified as administrative expenses have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. At the end of the year, these costs were:

As at December 31	2009	2008	2007
Canada	$ 1,814	$ 1,286	$ 1,721
United States	1,304	3,501	1,887
Other Countries	10	10	145
	$ 3,128	$ 4,797	$ 3,753

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. For the year ended December 31, 2009, the Company completed its impairment review of pre-production cost centres and determined that $26 million of costs should be charged to depreciation, depletion and amortization in the Consolidated Statement of Earnings (2008 – $38 million; 2007 – $68 million).

The prices used in the ceiling test evaluation of the Company's natural gas and crude oil reserves at December 31, 2009 were:

	2010	2011	2012	2013	2014	Cumulative % Change to 2020
Natural Gas *($/Mcf)*						
Canada	5.10	5.95	5.85	5.68	5.64	(1)%
United States	5.37	6.42	6.45	6.48	6.50	2%
Crude Oil *($/barrel)*						
Canada	65.42	67.06	68.30	67.02	66.69	(1)%
Natural Gas Liquids *($/barrel)*						
Canada	67.44	67.30	66.43	68.60	67.18	1%
United States	66.69	66.48	66.54	66.71	66.67	–

14. INVESTMENTS AND OTHER ASSETS

As at December 31	2009	2008
Long-Term Receivable	$ 81	$ –
Deferred Pension Plan and Savings Plan	52	59
Other	31	13
	$ 164	$ 72

15. LONG-TERM DEBT

As at December 31	Note	2009	2008
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	B	$ –	$ 1,410
Unsecured notes	C	1,194	1,020
		1,194	2,430
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	D	–	247
Unsecured notes	E	6,600	6,350
		6,600	6,597
Increase in Value of Debt Acquired	F	52	49
Debt Discounts and Financing Costs	G	(78)	(71)
Current Portion of Long-Term Debt	H	(200)	(250)
		$ 7,568	$ 8,755

A) OVERVIEW

REVOLVING CREDIT AND TERM LOAN BORROWINGS

At December 31, 2009, EnCana had in place a revolving credit facility for C$4.5 billion or its equivalent amount in U.S. dollars ($4.3 billion). The facility, which matures in October 2012, is fully revolving up to maturity. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, 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, 2009, one of EnCana's subsidiaries had in place a credit facility totalling $565 million. The facility, which matures in February 2013, is guaranteed by EnCana Corporation and is fully revolving up to maturity. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, 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.

Standby fees paid in 2009 relating to revolving credit and term loan agreements were approximately $4 million (2008 – $4 million; 2007 – $4 million).

UNSECURED NOTES

Unsecured notes include medium-term notes and senior notes that are issued from time to time under trust indentures.

EnCana has in place a debt shelf prospectus for Canadian unsecured medium-term notes in the amount of C$2.0 billion. The shelf prospectus provides that debt securities in Canadian 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 maturity dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was filed in May 2009 and expires in June 2011. At December 31, 2009, C$2.0 billion ($1.9 billion) of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions.

EnCana has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $4.0 billion under the multijurisdictional disclosure system ("MJDS"). 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 maturity dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was filed in March 2008 and expires in April 2010. At December 31, 2009, $3.5 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions.

B) CANADIAN REVOLVING CREDIT AND TERM LOAN BORROWINGS

	C$ Principal Amount	2009	2008
Bankers' Acceptances	$ –	$ –	$ 902
Commercial Paper	–	–	508
	$ –	$ –	$ 1,410

C) CANADIAN UNSECURED NOTES

	C$ Principal Amount	2009	2008
4.30% due March 12, 2012	$ 500	$ 478	$ 408
5.80% due January 18, 2018	750	716	612
	$ 1,250	$ 1,194	$ 1,020

D) U.S. REVOLVING CREDIT AND TERM LOAN BORROWINGS

	2009	2008
LIBOR	$ –	$ 184
Commercial Paper	–	63
	$ –	$ 247

E) U.S. UNSECURED NOTES

	2009	2008
4.60% due August 15, 2009	$ –	$ 250
7.65% due September 15, 2010	200	200
6.30% due November 1, 2011	500	500
4.75% due October 15, 2013	500	500
5.80% due May 1, 2014	1,000	1,000
5.90% due December 1, 2017	700	700
6.50% due May 15, 2019	500	–
8.125% due September 15, 2030	300	300
7.20% due November 1, 2031	350	350
7.375% due November 1, 2031	500	500
6.50% due August 15, 2034	750	750
6.625% due August 15, 2037	500	500
6.50% due February 1, 2038	800	800
	$ 6,600	$ 6,350

On May 4, 2009, EnCana completed a public offering in the United States of senior unsecured notes in the aggregate principal amount of US$500 million. The notes have a coupon rate of 6.5 percent and mature on May 15, 2019. The net proceeds of the offering were used to repay a portion of EnCana's bank and commercial paper indebtedness.

The 5.80% note due May 1, 2014 was issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. This note is 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 dates 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 20 years.

G) DEBT DISCOUNTS AND TRANSACTION COSTS

Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt and are being amortized using the effective interest method. During 2009, $4 million (2008 – $5 million) in transaction costs and discounts have been capitalized within long-term debt relating to the issuance of Canadian and U.S. unsecured notes.

H) CURRENT PORTION OF LONG-TERM DEBT

	2009	2008
4.60% due August 15, 2009	$ –	$ 250
7.65% due September 15, 2010	200	–
	$ 200	$ 250

I) MANDATORY DEBT PAYMENTS

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2010	$ –	$ 200	$ 200
2011	–	500	500
2012	500	–	478
2013	–	500	500
2014	–	1,000	1,000
Thereafter	750	4,400	5,116
Total	$ 1,250	$ 6,600	$ 7,794

16. 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 assets:

	2009	2008
Asset Retirement Obligation, Beginning of Year	$ 1,230	$ 1,437
Liabilities Incurred	21	54
Liabilities Settled	(52)	(110)
Liabilities Divested	(26)	(38)
Liabilities Transferred to Cenovus	(692)	–
Change in Estimated Future Cash Outflows	74	37
Accretion Expense	71	77
Foreign Currency Translation	161	(227)
Asset Retirement Obligation, End of Year	$ 787	$ 1,230

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,792 million (2008 – $6,569 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.38 percent (2008 – 6.04 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.

17. 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		2009		2008	
		Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year		750.4	$ 4,557	750.2	$ 4,479
Common Shares Issued under Option Plans		0.4	5	3.0	80
Common Shares Issued from PSU Trust		0.5	19	–	–
Stock-Based Compensation		–	1	–	11
Common Shares Purchased		–	–	(2.8)	(13)
Common Shares Cancelled	*(Note 3)*	(751.3)	(4,582)	–	–
New EnCana Common Shares Issued	*(Note 3)*	751.3	2,360	–	–
EnCana Special Shares Issued	*(Note 3)*	751.3	2,222	–	–
EnCana Special Shares Cancelled	*(Note 3)*	(751.3)	(2,222)	–	–
Common Shares Outstanding, End of Year		751.3	$ 2,360	750.4	$ 4,557

PERFORMANCE SHARE UNITS

In April 2009, the remaining 0.5 million Common Shares held in trust relating to EnCana's Performance Share Unit ("PSU") plan were sold for total consideration of $25 million. Of the amount received, $19 million was credited to Share capital and $6 million to Paid in surplus, representing the excess consideration received over the original price of the Common Shares acquired by the trust. Effective May 15, 2009, the trust agreement was terminated.

NORMAL COURSE ISSUER BID

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under eight consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to 37.5 million Common Shares under the renewed Bid which commenced on December 14, 2009 and terminates on December 13, 2010. During 2009, there were no purchases under the current or prior Bids.

In 2008, the Company purchased 4.8 million Common Shares for total consideration of approximately $326 million. Of the amount paid, $29 million was charged to Share capital and $297 million was charged to Retained earnings. Included in the Common Shares Purchased in 2008 are 2.0 million Common Shares distributed, valued at $16 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (See Note 19). For these Common Shares distributed, there was a $54 million adjustment to Retained earnings with a reduction to Paid in surplus of $70 million.

STOCK OPTIONS

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were granted. 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 10 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 19).

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 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. In addition, certain stock options granted since 2007 are performance based. The performance based stock options vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to pre-determined key measures (See Note 19).

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 10 years after the grant date and are all exercisable.

As at December 31, 2009, EnCana had 0.2 million stock options (2008 – 0.5 million) outstanding and exercisable with a weighted average exercise price of C$6.25 per stock option (2008 – C$11.62). The weighted average remaining contractual life of the stock options is 0.2 years. These stock options do not have TSARs attached.

At December 31, 2009, there were 9.6 million Common Shares reserved for issuance under stock option plans (2008 – 16.5 million; 2007 – 12.2 million).

At December 31, 2009, the balance in Paid in surplus relates to stock-based compensation programs.

ENCANA REPLACEMENT SHARE UNITS HELD BY CENOVUS EMPLOYEES

The share units described below include TSARs, Performance TSARs, Share Appreciation Rights ("SARs") and Performance SARs.

As part of the Split Transaction, on November 30, 2009, each holder of EnCana share units disposed of their right in exchange for the grant of EnCana Replacement share units and Cenovus Replacement share units. The terms and conditions of the Replacement share units are similar to the terms and conditions of the original share units.

Refer to Note 19 for information regarding share units and Replacement share units held by EnCana employees.

With respect to EnCana Replacement share units held by Cenovus employees and Cenovus Replacement share units held by EnCana employees, both EnCana and Cenovus have agreed to reimburse each other for share units exercised for cash by their respective employees. Accordingly, for EnCana Replacement share units held by Cenovus employees, EnCana has recorded a payable to Cenovus employees and a receivable due from Cenovus. The payable to Cenovus employees and the receivable due from Cenovus is based on the fair value of the EnCana Replacement share units determined using the Black-Scholes-Merton model (See Note 20). There is no impact on EnCana's net earnings for these share units held by Cenovus employees. No further EnCana Replacement share units will be granted to Cenovus employees.

As Cenovus employees may exercise EnCana Replacement TSARs and EnCana Replacement Performance TSARs in exchange for EnCana Common Shares, the following table is provided as at December 31, 2009.

As at December 31	2009	
	Number of EnCana Share Units (millions)	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
EnCana Replacement TSARs held by Cenovus Employees		
Outstanding, End of Year	8.3	29.36
Exercisable, End of Year	4.6	27.22
EnCana Replacement Performance TSARs held by Cenovus Employees		
Outstanding, End of Year	8.1	31.58
Exercisable, End of Year	1.5	32.03

PER SHARE AMOUNTS

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

For the years ended December 31 (in millions)	2009	2008	2007
Weighted Average Common Shares Outstanding – Basic	751.0	750.1	756.8
Effect of Stock Options and Other Dilutive Securities	0.4	1.7	7.8
Weighted Average Common Shares Outstanding – Diluted	751.4	751.8	764.6

18. CAPITAL STRUCTURE

The Company's capital structure consists of Shareholders' Equity plus Long-Term Debt, defined as the current and long-term portions of long-term debt. The Company's objectives when managing its capital structure are to:

i) maintain financial flexibility to preserve EnCana's access to capital markets and its ability to meet its financial obligations; and

ii) finance internally generated growth, as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

EnCana targets a Debt to Capitalization ratio of less than 40 percent. At December 31, 2009, EnCana's Debt to Capitalization ratio was 32 percent (December 31, 2008 – 28 percent) calculated as follows:

As at December 31	**2009**	2008
Debt	**$ 7,768**	$ 9,005
Total Shareholders' Equity	**16,614**	22,974
Total Capitalization	**$ 24,382**	$ 31,979
Debt to Capitalization Ratio	**32%**	28%

EnCana targets a Debt to Adjusted EBITDA of less than 2.0 times. At December 31, 2009, Debt to Adjusted EBITDA was 1.3x (December 31, 2008 – 0.6x; December 31, 2007 – 1.2x) calculated on a trailing 12-month basis as follows:

As at December 31	**2009**	2008	2007
Debt	**$ 7,768**	$ 9,005	$ 9,543
Net Earnings from Continuing Operations	**1,830**	6,499	3,447
Add (deduct):			
Interest, net	**405**	402	234
Income tax expense	**109**	2,720	682
Depreciation, depletion and amortization	**3,704**	4,035	3,657
Accretion of asset retirement obligation	**71**	77	63
Foreign exchange (gain) loss, net	**(22)**	423	(164)
(Gain) loss on divestitures	**2**	(141)	(65)
Adjusted EBITDA	**$ 6,099**	$ 14,015	$ 7,854
Debt to Adjusted EBITDA	**1.3x**	0.6x	1.2x

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures and definitions have remained unchanged over the periods presented. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

19. COMPENSATION PLANS

As part of the Split Transaction, each holder of EnCana share units disposed of their right in exchange for the grant of EnCana Replacement share units and Cenovus Replacement share units. The terms and conditions of the Replacement share units are similar to the terms and conditions of the original share units. Share units include TSARs, Performance TSARs, SARs and Performance SARs.

The original exercise price of the share units was apportioned to the EnCana and Cenovus Replacement share units based on a valuation methodology that included the weighted average trading price of the New EnCana Common Shares and the weighted average trading price of the Cenovus Common Shares on the Toronto Stock Exchange ("TSX") on a "when issued" basis on December 2, 2009.

For EnCana Replacement share units held by EnCana employees, EnCana accrues compensation cost over the vesting period based on the intrinsic method of accounting.

For Cenovus Replacement share units held by EnCana employees, EnCana accrues compensation cost over the vesting period based on the fair value of the Cenovus Replacement share units. The fair value of the Cenovus Replacement share units is determined using the Black-Scholes-Merton model. At December 31, 2009, the fair value was estimated using the following weighted average assumptions: risk free rate of 1.46 percent, dividend yield of 3.16 percent, volatility of 34.18 percent and Cenovus closing market share price of C$26.50 (See Note 20). No further Cenovus Replacement share units will be granted to EnCana employees.

Refer to Note 17 for information regarding EnCana Replacement share units held by Cenovus employees.

A) TANDEM SHARE APPRECIATION RIGHTS

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 17 have an associated TSAR attached to them whereby the option holder has the right 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 in lieu of exercising the option. The TSARs vest and expire under the same terms and conditions as the underlying option.

The following table summarizes information related to the TSARs:

As at December 31	2009		2008	
	Outstanding TSARs	Weighted Average Exercise Price	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**19,411,939**	**53.97**	18,854,141	48.44
Granted	**4,030,680**	**55.39**	4,420,272	70.11
Exercised – SARs	**(1,994,556)**	**42.65**	(3,173,443)	43.68
Exercised – Options	**(60,914)**	**34.89**	(82,936)	42.00
Forfeited	**(452,606)**	**60.11**	(606,095)	55.27
Exchanged for Replacement TSARs	**(20,934,543)**	**55.25**	–	–
Outstanding, End of Year	**–**	**–**	19,411,939	53.97
Exercisable, End of Year	**–**	**–**	8,452,111	46.45

The following table summarizes information related to the EnCana and Cenovus Replacement TSARs held by EnCana employees at December 31, 2009:

As at December 31, 2009	EnCana TSARs		Cenovus TSARs	
	Outstanding TSARs	Weighted Average Exercise Price	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Replacement TSARs exchanged November 30, 2009	12,556,585	28.83	12,556,585	26.07
Granted	12,775	29.96	–	–
Exercised – SARs	(54,075)	21.26	(29,840)	18.57
Exercised – Options	(206)	22.65	(1,206)	16.77
Forfeited	(41,865)	33.46	(42,845)	30.17
Outstanding, End of Year	12,473,214	28.85	12,482,694	26.08
Exercisable, End of Year	7,713,376	26.94	7,735,631	24.35

As at December 31, 2009	Outstanding EnCana TSARs			Exercisable EnCana TSARs	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
10.00 to 19.99	8,940	0.09	19.35	8,940	19.35
20.00 to 29.99	9,367,727	1.89	26.54	6,423,436	25.36
30.00 to 39.99	2,929,747	2.87	35.34	1,230,960	34.53
40.00 to 49.99	165,300	3.39	44.36	49,590	44.36
50.00 to 59.99	1,500	3.39	50.39	450	50.39
	12,473,214	2.14	28.85	7,713,376	26.94

As at December 31, 2009	Outstanding Cenovus TSARs			Exercisable Cenovus TSARs	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
10.00 to 19.99	1,097,538	0.13	18.21	1,097,538	18.21
20.00 to 29.99	8,781,794	2.11	24.96	5,724,948	24.16
30.00 to 39.99	2,521,012	3.05	32.85	888,440	32.63
40.00 to 49.99	82,350	3.44	42.82	24,705	42.82
	12,482,694	2.14	26.08	7,735,631	24.35

During the year, the Company recorded compensation costs of $5 million related to the outstanding TSARs prior to the Split Transaction, $11 million related to the EnCana Replacement TSARs and $46 million related to the Cenovus Replacement TSARs (2008 – reduction of compensation costs of $47 million; 2007 – compensation costs of $225 million).

B) PERFORMANCE TANDEM SHARE APPRECIATION RIGHTS

Beginning in 2007, under the terms of the existing Employee Stock Option Plan, EnCana granted Performance Tandem Share Appreciation Rights ("Performance TSARs") under which the employee has the right to receive a cash payment equal to the excess of the market price of EnCana Common Shares at the time of exercise over the grant price. Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to key predetermined measures. Performance TSARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance TSARs:

As at December 31	2009		2008	
	Outstanding Performance TSARs	Weighted Average Exercise Price	Outstanding Performance TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	12,979,725	63.13	6,930,925	56.09
Granted	7,751,720	55.31	7,058,538	69.40
Exercised – SARs	(144,707)	56.09	(287,299)	56.09
Exercised – Options	(980)	56.09	(5,123)	56.09
Forfeited	(2,041,565)	62.64	(717,316)	59.65
Exchanged for Replacement Performance TSARs	(18,544,193)	59.97	–	–
Outstanding, End of Year	–	–	12,979,725	63.13
Exercisable, End of Year	–	–	1,461,276	56.09

As at December 31, 2009	EnCana Performance TSARs		Cenovus Performance TSARs	
	Outstanding TSARs	Weighted Average Exercise Price	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Replacement Performance TSARs exchanged November 30, 2009	10,491,119	31.42	10,491,119	28.42
Exercised – SARs	(2,070)	29.45	–	–
Forfeited	(27,148)	31.59	(28,476)	28.49
Outstanding, End of Year	10,461,901	31.42	10,462,643	28.42
Exercisable, End of Year	2,235,899	31.55	2,236,641	28.54

As at December 31, 2009	Outstanding EnCana Performance TSARs			Exercisable EnCana Performance TSARs	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
20.00 to 29.99	7,279,507	3.24	29.22	1,563,005	29.45
30.00 to 39.99	3,182,394	3.12	36.44	672,894	36.44
	10,461,901	3.21	31.42	2,235,899	31.55

As at December 31, 2009	Outstanding Cenovus Performance TSARs			Exercisable Cenovus Performance TSARs	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
20.00 to 29.99	7,280,249	3.24	26.43	1,563,747	26.64
30.00 to 39.99	3,182,394	3.12	32.96	672,894	32.96
	10,462,643	3.21	28.42	2,236,641	28.54

During the year, EnCana recorded compensation costs of $4 million related to the outstanding Performance TSARs prior to the Split Transaction, $20 million related to the EnCana Replacement Performance TSARs and $19 million related to the Cenovus Replacement Performance TSARs (2008 – a reduction of compensation costs of $6 million; 2007 – compensation costs of $21 million).

C) SHARE APPRECIATION RIGHTS

EnCana has a program whereby employees may be granted SARs 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. SARs granted during 2009 and 2008 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date.

The following tables summarize information related to the SARs:

As at December 31	2009		2008	
	Outstanding SARs	Weighted Average Exercise Price	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	1,285,065	72.13	–	–
Granted	1,126,850	55.48	1,314,115	72.07
Exercised – SARs	(990)	43.50	–	–
Forfeited	(60,365)	66.64	(29,050)	69.42
Exchanged for Replacement SARs	(2,350,560)	64.30	–	–
Outstanding, End of Year	–	–	1,285,065	72.13
Exercisable, End of Year	–	–	–	–

As at December 31, 2009	EnCana SARs		Cenovus SARs	
	Outstanding SARs	Weighted Average Exercise Price	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Replacement SARs exchanged November 30, 2009	2,329,835	33.78	2,329,835	30.55
Granted	19,525	29.87	–	–
Forfeited	(5,875)	32.24	(5,875)	29.17
Outstanding, End of Year	2,343,485	33.75	2,323,960	30.55
Exercisable, End of Year	370,438	37.93	370,438	34.30

As at December 31, 2009	Outstanding EnCana SARs			Exercisable EnCana SARs	
Range of Exercise Price (C$)	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
20.00 to 29.99	1,099,490	4.12	28.96	7,640	25.79
30.00 to 39.99	1,061,795	3.30	36.52	308,138	36.71
40.00 to 49.99	177,200	3.44	46.39	53,160	46.39
50.00 to 59.99	5,000	3.46	50.09	1,500	50.09
	2,343,485	3.70	33.75	370,438	37.93

As at December 31, 2009	Outstanding Cenovus SARs			Exercisable Cenovus SARs	
Range of Exercise Price (C$)	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
20.00 to 29.99	1,140,395	4.11	26.29	14,780	25.62
30.00 to 39.99	1,048,065	3.25	33.53	315,008	33.53
40.00 to 49.99	135,500	3.44	43.43	40,650	43.43
	2,323,960	3.69	30.55	370,438	34.30

During the year, the Company recorded compensation costs of $1 million related to the outstanding SARs prior to the Split Transaction, $2 million related to the EnCana Replacement SARs and $5 million related to the Cenovus Replacement SARs (2008 – nil; 2007 – nil).

D) PERFORMANCE SHARE APPRECIATION RIGHTS

In 2009 and 2008, EnCana granted Performance Share Appreciation Rights ("Performance SARs") to certain employees 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 grant price. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to predetermined key measures. Performance SARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance SARs:

As at December 31	2009		2008	
	Outstanding Performance SARs	Weighted Average Exercise Price	Outstanding Performance SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	1,620,930	69.40	–	–
Granted	2,140,440	55.31	1,677,030	69.40
Forfeited	(256,235)	67.47	(56,100)	69.40
Exchanged for Replacement Performance SARs	(3,505,135)	60.94	–	–
Outstanding, End of Year	–	–	1,620,930	69.40
Exercisable, End of Year	–	–	–	–

As at December 31, 2009	EnCana Performance SARs		Cenovus Performance SARs	
	Outstanding SARs	Weighted Average Exercise Price	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Replacement Performance SARs exchanged November 30, 2009	3,481,203	31.99	3,481,203	28.94
Forfeited	(9,205)	29.97	(9,205)	27.11
Outstanding, End of Year	3,471,998	32.00	3,471,998	28.94
Exercisable, End of Year	293,344	36.44	293,344	32.96

As at December 31, 2009	Outstanding EnCana Performance SARs			Exercisable EnCana Performance SARs	
Range of Exercise Price (C$)	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
20.00 to 29.99	2,085,310	4.11	29.04	–	–
30.00 to 39.99	1,386,688	3.12	36.44	293,344	36.44
	3,471,998	3.72	32.00	293,344	36.44

As at December 31, 2009	Outstanding Cenovus Performance SARs			Exercisable Cenovus Performance SARs	
Range of Exercise Price (C$)	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
20.00 to 29.99	2,085,310	4.11	26.27	–	–
30.00 to 39.99	1,386,688	3.12	32.96	293,344	32.96
	3,471,998	3.72	28.94	293,344	32.96

During the year, the Company recorded compensation costs of $1 million related to the outstanding Performance SARs prior to the Split Transaction, $3 million related to the EnCana Replacement Performance SARs and $7 million related to the Cenovus Replacement Performance SARs (2008 – nil; 2007 – nil).

E) DEFERRED SHARE UNITS

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. DSUs granted to Directors vest immediately. DSUs expire on December 15th of the year following the Director's resignation or employee's termination.

Employees have the option to convert either 25 or 50 percent of their annual High Performance Results ("HPR") award into DSUs. The number of DSUs is based on the value of the award divided by the closing value of EnCana's share price at the end of the performance period of the HPR award. DSUs vest immediately, can be redeemed in accordance with the terms of the agreement and expire on December 15th of the year following the year of termination.

Pursuant to the Split Transaction, additional EnCana DSUs were credited to employees, officers and directors of EnCana to compensate employees, officers and directors for the loss in value of the EnCana Common Shares. The number of EnCana DSUs credited to each was determined so that, immediately after the adjustment, each participant has an aggregate number of EnCana DSUs based on a formula that the EnCana DSUs fair value would equal the fair value of the exchanged EnCana DSUs. EnCana DSUs credited to employees, officers and directors of Cenovus were exchanged for Cenovus DSUs, each having a notional value equal to the value of one Cenovus Common Share.

The following table summarizes information related to the DSUs:

As at December 31	2009	2008
	Outstanding DSUs	Outstanding DSUs
Canadian Dollar Denominated		
Outstanding, Beginning of Year	656,841	589,174
Granted	74,600	85,792
Converted from HPR awards	46,884	15,883
EnCana DSUs exchanged for Cenovus DSUs	(367,293)	–
EnCana DSU credit adjustment	321,375	–
Units, in Lieu of Dividends	22,749	–
Redeemed	(83,009)	(34,008)
Outstanding, End of Year	672,147	656,841

During the year, the Company recorded compensation costs of $8 million related to the outstanding DSUs (2008 – $2 million; 2007 – $14 million).

F) PERFORMANCE SHARE UNITS

Performance Share Units ("PSUs") were granted in 2003, 2004 and 2005 and entitled employees 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 PSUs granted. PSUs vested over a three-year period from the date granted. If EnCana's performance was at or above a specified level compared to a pre-determined peer group, payments ranged from one-half to two times the PSU. At December 31, 2009, there are no PSUs outstanding.

PSUs granted in 2003 were paid out in cash at 75 percent of the number granted. PSUs granted in 2004 were paid out in Common Shares at 100 percent of the number granted. PSUs granted in 2005 were paid out in Common Shares at 125 percent of the number granted.

The following table summarizes information related to the PSUs:

As at December 31	2009		2008	
	Outstanding PSUs	Average Share Price	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	–	–	1,685,036	38.79
Granted	–	–	408,686	70.77
Distributed	–	–	(2,042,541)	45.34
Forfeited	–	–	(51,181)	38.32
Outstanding, End of Year	–	–	–	–

During the year, the Company did not record any compensation costs related to the outstanding PSUs (2008 – $1 million; 2007 – $43 million).

G) PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company sponsors defined benefit and defined contribution plans, providing pension and other post-employment benefits ("OPEB") to its employees. In the past, the defined benefit plan was offered, however it has been closed to new entrants beginning January 1, 2003. The average remaining service period of the active employees covered by the defined benefit pension plan is six years. The average remaining service period of the active employees covered by the OPEB plan is 10 years.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recent filing was dated December 31, 2008 and the next required filing will be as at December 31, 2011.

Information related to defined benefit pension and other post-employment benefit plans, based on actuarial estimations as at December 31, 2009 is as follows:

	Pension Benefits		OPEB	
As at December 31	**2009**	2008	**2009**	2008
Fair Value of Plan Assets, End of Year	**$ 251**	$ 233	**$ –**	$ –
Accrued Benefit Obligation, End of Year	**277**	263	**62**	55
Funded Status – Plan Assets (less) than Benefit Obligation	**(26)**	(30)	**(62)**	(55)
Amounts Not Recognized:				
Unamortized net actuarial (gain) loss	**59**	74	**1**	(5)
Unamortized past service costs	**2**	4	**1**	1
Net transitional asset (liability)	**–**	–	**5**	10
Accrued Benefit Asset (Liability)	**$ 35**	$ 48	**$ (55)**	$ (49)

The 2009 pension benefit obligation was determined using the weighted average discount rate of 5.75 percent (2008 – 6.25 percent) and a weighted average rate of compensation increase of 4.15 percent (2008 – 4.16 percent). The 2009 OPEB obligation was determined using the weighted average discount rate of 5.93 percent (2008 – 6.25 percent) and a weighted average rate of compensation increase of 6.31 percent (2008 – 6.00 percent).

Accrued benefit obligation and plan assets of $50 million were allocated in conjunction with the Split Transaction for active employees who are with Cenovus.

The periodic pension and OPEB expense is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2009**	2008	2007	**2009**	2008	2007
Defined Benefit Plans Expense	**$ 20**	$ 9	$ 8	**$ 14**	$ 12	$ 12
Defined Contribution Plans Expense	**43**	44	34	**–**	–	–
Total Benefit Plans Expense	**$ 63**	$ 53	$ 42	**$ 14**	$ 12	$ 12

The Company's pension plan assets were invested in the following as at December 31, 2009: 39 percent Domestic Equity (2008 – 34 percent), 23 percent Foreign Equity (2008 – 25 percent), 29 percent Bonds (2008 – 33 percent), and 9 percent Real Estate and Other (2008 – 8 percent). The expected long-term rate of return is 6.75 percent. 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 asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company's contributions to the defined benefit pension plans are subject to the results of the actuarial valuation and direction by the Human Resources and Compensation Committee. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2009 (2008 – $1 million; 2007 – $1 million). EnCana's contribution to the defined benefit pension plans for the year ended December 31, 2009 was $12 million (2008 – $8 million; 2007 – $ 8 million).

The Company's OPEB plans are funded on an as required basis.

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

	Pension Benefits	OPEB
2010	$ 16	$ 2
2011	17	3
2012	17	3
2013	18	4
2014	18	4
2015 – 2019	95	26
Total	$ 181	$ 42

20. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

EnCana's financial assets and liabilities include cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows:

A) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments except for the amounts associated with Replacement share units issued as part of the Split Transaction, as discussed in Notes 17 and 19.

At December 31, 2008, the fair value of the partnership contribution receivable approximates its carrying amount due to the specific nature of the instruments in relation to the creation of the Integrated Oil joint venture. Further information about this note is disclosed in Note 11.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost using the effective interest method of amortization. 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 expected to be available to the Company at period end.

The fair value of financial assets and liabilities were as follows:

As at December 31	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading:				
Cash and cash equivalents	$ 4,275	$ 4,275	$ 354	$ 354
Accounts receivable and accrued revenues (1)	75	75	–	–
Risk management assets (2)	360	360	3,052	3,052
Loans and Receivables:				
Accounts receivable and accrued revenues	1,105	1,105	1,436	1,436
Partnership contribution receivable (2)	–	–	3,147	3,147
Financial Liabilities				
Held-for-trading:				
Accounts payable and accrued liabilities (3), (4)	$ 155	$ 155	$ –	$ –
Risk management liabilities (2)	168	168	50	50
Other Financial Liabilities:				
Accounts payable and accrued liabilities	1,988	1,988	2,448	2,448
Long-term debt (2)	7,768	8,527	9,005	8,242

(1) Represents amounts due from Cenovus for EnCana Replacement share units held by Cenovus employees as discussed in Note 17.

(2) Including current portion.

(3) Includes amounts due to Cenovus employees for EnCana Replacement share units held as discussed in Note 17.

(4) Includes amounts due to Cenovus for Cenovus Replacement share units held by EnCana employees as discussed in Notes 17 and 19.

B) RISK MANAGEMENT ASSETS AND LIABILITIES

NET RISK MANAGEMENT POSITION

As at December 31	2009	2008
Risk Management		
Current asset	$ 328	$ 2,818
Long-term asset	32	234
	360	3,052
Risk Management		
Current liability	126	43
Long-term liability	42	7
	168	50
Net Risk Management Asset	$ 192	$ 3,002

SUMMARY OF UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	2009			2008		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural Gas	$ 298	$ 88	$ 210	$ 2,941	$ 10	$ 2,931
Crude Oil	62	72	(10)	92	40	52
Power	–	8	(8)	19	–	19
Total Fair Value	$ 360	$ 168	$ 192	$ 3,052	$ 50	$ 3,002

NET FAIR VALUE METHODOLOGIES USED TO CALCULATE UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	2009	2008
Prices actively quoted	$ 285	$ 2,055
Prices sourced from observable data or market corroboration	(93)	947
Total Fair Value	$ 192	$ 3,002

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

NET FAIR VALUE OF COMMODITY PRICE POSITIONS AT DECEMBER 31, 2009

	Notional Volumes	Term	Average Price	Fair Value
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,852 MMcf/d	2010	6.05 US$/Mcf	$ 223
NYMEX Fixed Price	640 MMcf/d	2011	6.57 US$/Mcf	63
NYMEX Fixed Price	267 MMcf/d	2012	6.55 US$/Mcf	8
Basis Contracts *				
Canada		2010		(4)
United States		2010		(3)
Canada and United States		2011-2013		(78)
				209
Other Financial Positions **				1
Natural Gas Fair Value Position				$ 210
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	5,400 bbls/d	2010	76.99 US$/bbl	$ (10)
Crude Oil Fair Value Position				$ (10)
Power Purchase Contracts				
Power Fair Value Position				$ (8)

* EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

** Other financial positions are part of the ongoing operations of the Company's proprietary production management.

EARNINGS IMPACT OF REALIZED AND UNREALIZED GAINS (LOSSES) ON RISK MANAGEMENT POSITIONS

	Realized Gain (Loss)		
For the years ended December 31	**2009**	2008	2007
Revenues, Net of Royalties	$ 4,420	$ (309)	$ 1,601
Operating Expenses and Other	(44)	28	3
Gain (Loss) on Risk Management	$ 4,376	$ (281)	$ 1,604

	Unrealized Gain (Loss)		
For the years ended December 31	**2009**	2008	2007
Revenues, Net of Royalties	$ (2,640)	$ 2,717	$ (1,239)
Operating Expenses and Other	(40)	12	4
Gain (Loss) on Risk Management	$ (2,680)	$ 2,729	$ (1,235)

RECONCILIATION OF UNREALIZED RISK MANAGEMENT POSITIONS FROM JANUARY 1 TO DECEMBER 31, 2009

	2009		2008	2007
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ 2,892			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	1,696	$ 1,696	$ 2,448	$ 353
Fair Value of Contracts in Place at Transition that Expired During the Year	–	–	–	16
Foreign Exchange Translation Adjustment on Canadian Dollar Contracts	4	–	–	–
Fair Value of Contracts Transferred to Cenovus	(24)	–	–	–
Fair Value of Contracts Realized During the Year	(4,376)	(4,376)	281	(1,604)
Fair Value of Contracts Outstanding, End of Year	$ 192	$ (2,680)	$ 2,729	$ (1,235)

COMMODITY PRICE SENSITIVITIES

The following table summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting pre-tax net earnings as at December 31, 2009 as follows:

	10% Price Increase	10% Price Decrease
Natural gas price	$ (608)	$ 608
Crude oil price	(9)	9
Power price	5	(5)

C) RISKS ASSOCIATED WITH FINANCIAL ASSETS AND LIABILITIES

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The fair value or future cash flows of financial assets or liabilities may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

COMMODITY PRICE RISK

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors (the "Board"). The Company's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on crude oil with swaps which fix WTI NYMEX prices.

Power – The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

CREDIT RISK

Credit risk arises from the potential the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. At December 31, 2009, cash equivalents include high-grade, short-term securities, placed with Governments, crown corporations and financial institutions with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

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. As at December 31, 2009, over 93 percent (2008 – 95 percent) of EnCana's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2009, EnCana had two counterparties (2008 – two 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. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

LIQUIDITY RISK

Liquidity risk is the risk the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 18, EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times to steward the Company's overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at December 31, 2009, EnCana had available unused committed bank credit facilities in the amount of $4.9 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, in the amount of $5.4 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On November 30, 2009 following the completion of the Split Transaction (See Note 3), Standard & Poor's Ratings Services lowered the rating to "BBB+" from "A-" and changed the outlook to "Stable" from "CreditWatch" with negative implications. Moody's Investors Service affirmed the rating of "Baa2" with a "Stable" outlook. DBRS Limited maintained the rating of "A (low)" and changed the outlook to "Stable" from "Under Review with Developing Implications". These credit ratings remained unchanged at December 31, 2009.

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 – 3 Years	4 – 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 2,143	$ –	$ –	$ –	**$ 2,143**
Risk Management Liabilities	126	34	8	–	**168**
Long-Term Debt *	685	1,875	2,282	9,936	**14,778**

* Principal and interest, including current portion.

EnCana's total long-term debt obligations were $14,778 million at December 31, 2009. Further information on Long-Term Debt is contained in Note 15.

FOREIGN EXCHANGE RISK

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company's reported results. EnCana's functional currency is Canadian dollars; however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations is not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

EnCana's foreign exchange (gain) loss primarily includes foreign exchange gains and losses on U.S. dollar cash and short-term investments, unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada, foreign exchange gains and losses on the translation of the U.S. dollar partnership contribution receivable issued from Canada and unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated risk management assets and liabilities.

At December 31, 2009, EnCana had $5,600 million in U.S. dollar debt issued from Canada ($5,350 million at December 31, 2008). At December 31, 2009, as a result of the Split Transaction (See Note 3), EnCana had nil related to the U.S. dollar partnership contribution receivable ($3,147 million at December 31, 2008). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $20 million change in foreign exchange (gain) loss at December 31, 2009 (2008 – $18 million).

INTEREST RATE RISK

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. Typically, the Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2009, the Company had no floating rate debt. Therefore, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt was nil (2008 – $12 million).

21. SUPPLEMENTARY INFORMATION

A) NET CHANGE IN NON-CASH WORKING CAPITAL FROM CONTINUING OPERATIONS

For the years ended December 31	2009	2008	2007
Operating Activities			
Accounts receivable and accrued revenues	$ (487)	$ 452	$ 33
Inventories	(271)	211	46
Accounts payable and accrued liabilities	567	(354)	(78)
Income tax payable	1,237	(589)	(5)
Discontinued operations	(1,075)	(1,073)	(104)
	$ (29)	$ (1,353)	$ (108)
Investing Activities			
Accounts payable and accrued liabilities	$ (50)	$ 34	$ 51

B) SUPPLEMENTARY CASH FLOW INFORMATION – CONTINUING OPERATIONS

For the years ended December 31	2009	2008	2007
Interest Paid	$ 507	$ 574	$ 486
Income Taxes Paid	$ 766	$ 1,574	$ 1,262

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2009	2010	2011	2012	2013	2014	Thereafter	Total
Pipeline Transportation	$ 438	$ 485	$ 506	$ 501	$ 497	$ 1,911	$ 4,338
Purchases of Goods and Services	377	365	275	224	198	684	2,123
Operating Leases*	69	71	87	160	169	3,238	3,794
Capital Commitments	127	169	67	–	38	–	401
Other Long-Term Commitments	2	2	2	2	1	24	33
Total	$ 1,013	$ 1,092	$ 937	$ 887	$ 903	$ 5,857	$ 10,689
Cenovus's Share of Costs**	$ 90	$ 111	$ 68	$ 72	$ 76	$ 1,576	$ 1,993

* Primarily related to office space associated with The Bow.

** Tenant costs associated with The Bow as well as current office space lease arrangements remain with EnCana. Cenovus and EnCana have entered into an agreement to share in the costs.

EnCana has entered into various commitments primarily related to demand charges for firm transportation, leasing of office space, procurement arrangements for goods and services, as well as other minor spending commitments. EnCana and Cenovus have entered into an arrangement whereby the portion of the commitments related to the Cenovus operations have been transferred to Cenovus as a result of the Split Transaction and are excluded from the table above.

In addition to the above, the Company has made commitments related to its risk management program (See Note 20).

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

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. All but one of these lawsuits had been settled prior to 2009. Without admitting any liability whatsoever, the remaining lawsuit was settled on October 16, 2009.

ASSET RETIREMENT

EnCana 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 $787 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 EnCana 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.

23. 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	2009	2008	2007
Net Earnings – Canadian GAAP		$ 1,862	$ 5,944	$ 3,959
Less:				
Net Earnings From Discontinued Operations – Canadian GAAP		32	(555)	512
Net Earnings From Continuing Operations – Canadian GAAP		1,830	6,499	3,447
Increase (Decrease) in Net Earnings From Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	*A*	–	–	(15)
Operating	*D ii), H*	(16)	(46)	3
Depreciation, depletion and amortization	*B, D ii)*	(10,926)	(1,755)	86
Administrative	*D ii)*	22	(27)	1
Interest, net	*A*	–	(3)	(2)
Foreign exchange (gain) loss, net	*G*	128	–	–
Stock-Based compensation – options	*C*	–	2	(5)
Income tax expense	*E*	3,378	695	(204)
Net Earnings (Loss) From Continuing Operations – U.S. GAAP		(5,584)	5,365	3,311
Net Earnings (Loss) From Discontinued Operations – U.S. GAAP		32	(555)	512
Net Earnings (Loss) – U.S. GAAP		$ (5,552)	$ 4,810	$ 3,823
Net Earnings (Loss) From Continuing Operations per Common Share				
Basic		$ (7.44)	$ 7.15	$ 4.37
Diluted		$ (7.44)	$ 7.14	$ 4.33
Net Earnings (Loss) per Common Share				
Basic		$ (7.39)	$ 6.41	$ 5.05
Diluted		$ (7.39)	$ 6.40	$ 5.00

CONSOLIDATED STATEMENT OF EARNINGS – U.S. GAAP

For the years ended December 31	Note	2009	2008	2007
Revenues, Net of Royalties	A	$ 11,114	$ 21,053	$ 14,370
Expenses				
Production and mineral taxes		171	478	291
Transportation and selling		1,280	1,704	1,264
Operating	D ii), H	1,643	2,029	1,847
Purchased product		1,460	2,426	2,770
Depreciation, depletion and amortization	B, D ii)	14,630	5,790	3,571
Administrative	D ii)	455	474	355
Interest, net	A	405	405	236
Accretion of asset retirement obligation		71	77	63
Foreign exchange (gain) loss, net	G	(150)	423	(164)
Stock-Based compensation – options	C	–	(2)	5
(Gain) loss on divestitures		2	(141)	(65)
Net Earnings (Loss) Before Income Tax		(8,853)	7,390	4,197
Income tax expense (recovery)	E	(3,269)	2,025	886
Net Earnings (Loss) From Continuing Operations – U.S. GAAP		(5,584)	5,365	3,311
Net Earnings (Loss) From Discontinued Operations – U.S. GAAP		32	(555)	512
Net Earnings (Loss) – U.S. GAAP		$ (5,552)	$ 4,810	$ 3,823
Net Earnings (Loss) From Continuing Operations per Common Share – U.S. GAAP				
Basic		$ (7.44)	$ 7.15	$ 4.37
Diluted		$ (7.44)	$ 7.14	$ 4.33
Net Earnings (Loss) From Discontinued Operations per Common Share – U.S. GAAP				
Basic		$ 0.05	$ (0.74)	$ 0.68
Diluted		$ 0.05	$ (0.74)	$ 0.67
Net Earnings (Loss) per Common Share – U.S. GAAP				
Basic		$ (7.39)	$ 6.41	$ 5.05
Diluted		$ (7.39)	$ 6.40	$ 5.00

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2009	2008	2007
Net Earnings (Loss) – U.S. GAAP		$ (5,552)	$ 4,810	$ 3,823
Change in Fair Value of Financial Instruments	A	–	2	–
Foreign Currency Translation Adjustment	B, D ii), F, G	1,970	(2,217)	1,707
Compensation Plans	D i), F	13	(12)	1
Comprehensive Income (Loss)		$ (3,569)	$ 2,583	$ 5,531

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2009	2008	2007
Balance, Beginning of Year		$ 811	$ 3,038	$ 1,330
Change in Fair Value of Financial Instruments	A	–	2	–
Foreign Currency Translation Adjustment	B, D ii), F,G	1,970	(2,217)	1,707
Compensation Plans	D i), F	13	(12)	1
Net Distribution to Cenovus Energy		(2,096)	–	–
Balance, End of Year		$ 698	$ 811	$ 3,038

CONSOLIDATED STATEMENT OF RETAINED EARNINGS – U.S. GAAP

For the years ended December 31	2009	2008	2007
Retained Earnings, Beginning of Year	$ 16,344	$ 12,976	$ 11,374
Net Earnings (Loss)	(5,552)	4,810	3,823
Dividends on Common Shares	(1,051)	(1,199)	(603)
Charges for Normal Course Issuer Bid	–	(243)	(1,618)
Net Distribution to Cenovus Energy	(4,937)	–	–
Retained Earnings, End of Year	$ 4,804	$ 16,344	$ 12,976

CONDENSED CONSOLIDATED BALANCE SHEET – U.S. GAAP

As at December 31		2009		2008	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current Assets	D i), H	$ 5,795	$ 5,750	$ 5,602	$ 5,604
Property, Plant and Equipment	B, D ii)				
(includes unproved properties and major development projects of $3,128 and $4,797 as of December 31, 2009 and 2008, respectively)		45,503	45,393	55,524	55,483
Accumulated Depreciation, Depletion and Amortization		(19,330)	(31,738)	(23,614)	(25,135)
Property, Plant and Equipment, net		26,173	13,655	31,910	30,348
(Full Cost Method for Oil and Gas Activities)					
Investments and Other Assets	D i)	164	119	72	26
Partnership Contribution Receivable		–	–	2,834	2,834
Risk Management		32	32	234	234
Goodwill		1,663	1,663	2,426	2,426
Assets of Discontinued Operations		–	–	4,169	4,169
		$ 33,827	$ 21,219	$ 47,247	$ 45,641
Liabilities and Shareholders' Equity					
Current Liabilities	A, D i), ii)	$ 4,245	$ 4,530	$ 3,894	$ 4,201
Long-Term Debt		7,568	7,568	8,755	8,755
Other Liabilities	A, D i), ii)	1,185	1,220	576	613
Risk Management		42	42	7	7
Asset Retirement Obligation		787	787	1,230	1,230
Future Income Taxes	E	3,386	(829)	6,917	6,196
Liabilities of Discontinued Operations		–	–	2,894	2,894
		17,213	13,318	24,273	23,896
Share Capital	C				
Common shares, no par value		2,360	2,393	4,557	4,590
Outstanding: 2009 – 751.3 million shares					
2008 – 750.4 million shares					
Paid in Surplus		6	6	–	–
Retained Earnings		13,493	4,804	17,584	16,344
Accumulated Other Comprehensive Income	A, B, D i), ii), F, G	755	698	833	811
		16,614	7,901	22,974	21,745
		$ 33,827	$ 21,219	$ 47,247	$ 45,641

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS – U.S. GAAP

For the years ended December 31	2009	2008	2007
Operating Activities			
Net earnings (loss) from continuing operations	$ (5,584)	$ 5,365	$ 3,311
Depreciation, depletion and amortization	14,630	5,790	3,571
Future income taxes	(5,177)	1,028	(673)
Unrealized (gain) loss on risk management	2,680	(2,729)	1,251
Unrealized foreign exchange (gain) loss	(359)	417	41
Accretion of asset retirement obligation	71	77	63
(Gain) loss on divestitures	2	(141)	(65)
Other	320	(8)	97
Cash flow from discontinued operations	149	(441)	678
Net change in other assets and liabilities	23	(254)	(10)
Net change in non-cash working capital from continuing operations	18	(1,353)	71
Net change in non-cash working capital from discontinued operations	1,100	1,210	(73)
Cash From Operating Activities	$ 7,873	$ 8,961	$ 8,262
Cash (Used in) Investing Activities	$ (4,806)	$ (7,517)	$ (8,179)
Cash From (Used in) Financing Activities	$ 835	$ (1,439)	$ (119)

Notes:

A) 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 was recognized into earnings when realized. As at December 31, 2007, under Canadian GAAP, the remaining transition amount had been fully recognized into net earnings.

The Company adopted Financial Accounting Standards Board ("FASB") Accounting Standards for derivatives and hedging effective January 1, 2001. The standard 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. Any gain or loss on implementation of this U.S. GAAP standard was recorded in Other Comprehensive Income. These transitional amounts are recognized into net earnings as the positions are realized.

Unrealized gain (loss) on derivatives relates to:

For the years ended December 31	2009	2008	2007
Commodity Prices (Revenues, net of royalties)	$ (2,640)	$ 2,717	$ (1,249)
Operating Expenses and Other	(40)	12	–
Interest and Currency Swaps (Interest, net)	–	(3)	(2)
Total Unrealized Gain (Loss)	$ (2,680)	$ 2,726	$ (1,251)
Amounts Allocated to Continuing Operations	$ (2,680)	$ 2,726	$ (1,251)
Amounts Allocated to Discontinued Operations	–	–	–
	$ (2,680)	$ 2,726	$ (1,251)

In 2008, the remaining balance related to the transitional amounts in Accumulated Other Comprehensive Income was recognized in net earnings for U.S. GAAP.

B) FULL COST ACCOUNTING

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum, net of applicable income taxes, of the present value, discounted at 10 percent, of the estimated future net revenues calculated on the basis of estimated value of future production from proved reserves using an average price based upon the prior 12-month period, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs.

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 and future development and production costs to determine whether impairment exists. The impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are also calculated by reference to proved reserves estimated using estimated future prices and costs.

At December 31, 2009, the Company's capitalized costs of oil and gas properties exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write down of $11.1 billion charged to depreciation, depletion and amortization ($7.6 billion after-tax). This write down included $6.3 billion from properties in the United States ($4.0 billion after-tax) (2008 – $1.8 billion charged to depreciation, depletion and amortization; $1.1 billion after-tax) and $4.8 billion from properties in Canada ($3.6 billion after-tax) (2008 – nil). Additional depletion was also recorded in 2001, and certain prior years, as a result of the ceiling test difference between Canadian GAAP and U.S. GAAP. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

The U.S. GAAP adjustment for the difference in depletion calculations results in an impact to depreciation, depletion and amortization charges and foreign currency translation adjustment of $171.8 million decrease and $0.5 million decrease respectively (2008 – $13.3 million decrease and $0.8 million increase; 2007 – $85.4 million decrease and $2.9 million increase).

C) STOCK-BASED COMPENSATION – CPL REORGANIZATION

U.S. GAAP requires that 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 Limited ("CPL"), an equity restructuring occurred that resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 17. 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) COMPENSATION PLANS

i) Pensions and Other Post-Employment Benefits

For the year ended December 31, 2006, the Company adopted, for U.S. GAAP purposes, the standard for retirement benefits. The standard requires EnCana to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through Other Comprehensive Income. Canadian GAAP does not require the Company to recognize the funded status of these plans on its balance sheet.

ii) Liability-Based Stock Compensation Plans

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, the Company adopted the standard for stock compensation for the year ended December 31, 2006 using the modified-prospective approach. Under the standard, the intrinsic-value method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights, performance share appreciation rights and deferred share units, are required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. The current period adjustments have the following impact:

- Net capital assets decreased by $56.4 million (2008 – $37.7 million increase)
- Current liabilities decreased by $76.7 million (2008 – $111.4 million increase)
- Other liabilities increased by $3.2 million (2008 – $0.5 million decrease)
- Other comprehensive income decreased by $3.2 million (2008 – $5.9 million increase)
- Operating expenses decreased by $31.5 million (2008 – $46.1 million increase)
- Administrative expenses decreased by $21.8 million (2008 – $26.7 million increase)
- Depreciation, depletion and amortization expenses decreased by $0.8 million (2008 – $9.9 million increase)

E) INCOME TAXES

Under U.S. GAAP, enacted tax rates and legislative changes are used to calculate current and future income taxes, whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2007, a Canadian tax legislative change was substantively enacted for Canadian GAAP; however, this tax legislative change was not considered enacted for U.S. GAAP by December 31, 2007. This tax legislative change was still not considered enacted for U.S. GAAP by December 31, 2009. Accordingly, there was no difference in 2009 (2008 – nil; 2007– increase to income tax expense of $179 million) for U.S. GAAP.

The remaining differences resulted from 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 which 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	2009	2008	2007
Net Earnings (Loss) Before Income Tax – U.S. GAAP	$ (8,853)	$ 7,390	$ 4,197
Canadian Statutory Rate	29.2%	29.7%	32.3%
Expected Income Tax	(2,585)	2,191	1,356
Effect on Taxes Resulting from:			
Statutory and other rate differences	(389)	15	41
Effect of tax rate changes	–	–	(301)
International financing	(101)	(268)	(62)
Foreign exchange (gains) losses not included in net earnings	20	47	–
Non-taxable capital (gains) losses	(71)	84	(124)
Other	(143)	(44)	(24)
Income Tax – U.S. GAAP	$ (3,269)	$ 2,025	$ 886
Effective Tax Rate	36.9%	27.4%	21.1%

The net future income tax liability is comprised of:

As at December 31	2009	2008
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	$ –	$ 4,635
Timing of partnership items	78	924
Risk management	75	955
Future Tax Assets		
Tax values of property, plant and equipment in excess of carrying amounts	(802)	–
Non-capital and net operating losses carried forward	(174)	(46)
Other	(6)	(272)
Net Future Income Tax Liability	$ (829)	$ 6,196

F) OTHER COMPREHENSIVE INCOME

The U.S. GAAP standard for retirement benefits requires the funded status of defined benefit and post-employment plans to be presented on the balance sheet and changes in the funded status be recorded through comprehensive income. In 2009, a gain of $12.5 million, net of tax was recognized in Other Comprehensive Income (2008 – $12 million loss, net of tax) as noted in D i). On adoption of the standard, as required, the transitional amount of $48 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

The foreign currency translation adjustment includes the effect of the accumulated U.S. GAAP differences.

G) FOREIGN CURRENCY TRANSLATION

In 2009 in accordance with Canadian GAAP, the Company recognized a foreign exchange loss arising from the translation of an intercompany transaction that reduced the Company's net investment in a self-sustaining foreign operation. Under U.S. GAAP intra-entity foreign currency transactions that are of a long-term investment nature between entities that are consolidated in the Company's financial statements are not included in determining net income but reported as translation adjustments. Accordingly, net earnings under U.S. GAAP increased by $128 million with a corresponding decrease to foreign currency translation.

H) CURRENT ASSETS

In 2009, the Company reversed an impairment of inventory previously recorded in 2008 under Canadian GAAP. U.S. GAAP does not permit the reversal of inventory impairments. Accordingly, net earnings before income tax under U.S. GAAP decreased by $47 million with a corresponding decrease to the inventory balance.

I) CONSOLIDATED STATEMENT OF CASH FLOWS

Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP. Cash tax on sale of assets presented as investing activities under Canadian GAAP is presented as operating activities under U.S. GAAP.

J) DIVIDENDS DECLARED ON COMMON STOCK

For the years ended December 31	2009	2008	2007
Dividends per share	$ 1.40	$ 1.60	$ 0.80

K) RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2009, EnCana prospectively adopted, for U.S. GAAP purposes, ASC 805-10, *"Business Combinations"*. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard had no material impact on EnCana's U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.

As of January 1, 2009, EnCana adopted, for U.S. GAAP purposes, ASC 810-10 *"Consolidation"*. This standard requires a noncontrolling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP consolidated statement of earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the noncontrolling interest and to disclose these respective amounts. The adoption of this standard did not have an impact on EnCana's Consolidated Financial Statements for U.S. GAAP.

In June 2009, FASB issued the Accounting Standards Update ("ASU") 2009-01, *"The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles"* which establishes the FASB Accounting Standards Codification ("ASC") as the sole source of authoritative accounting principles recognized by FASB for nongovernmental entities. Rules and interpretive releases of the SEC also continue to be sources of authoritative U.S. GAAP for SEC registrants. The Codification was not intended to change existing U.S. GAAP and therefore it did not have an effect on EnCana's Consolidated Financial Statements under U.S. GAAP.

As of December 31, 2009, EnCana prospectively adopted the new reserves requirements and reporting that arise from the completion of the U.S. Securities Exchange Commission's project, *Modernization of Oil and Gas Reporting* and FASB's Accounting Standards Update 2010-03 *Oil and Gas Reserve Estimation and Disclosures*. The new SEC rules and FASB standard include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Additionally, oil and gas reserves are now reported using an average price based upon the prior 12-month period rather than year-end prices. In addition the FASB standard affected the amounts reported in the Supplementary Oil and Gas Information Topic 932 as discussed in that supplementary information.

SUPPLEMENTARY OIL AND GAS INFORMATION (unaudited)

For the year ended December 31, 2009 (Prepared in US$)

The tables in this Appendix set forth oil and gas information prepared by EnCana in accordance with FASB Standards.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, constant price and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs 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 to the extent provided by contractual arrangements such as price risk management activities, in existence at year-end and to account for 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 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 Market Optimization interests.

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)			Bitumen (3) (millions of barrels)
	Canada	United States	**Total**	Canada (4)	United States	**Total**	**Canada**
2007							
Beginning of year	7,028	5,390	**12,418**	279.8	54.0	**333.8**	**799.6**
Revisions and improved recovery	87	78	**165**	12.8	3.6	**16.4**	**62.7**
Extensions and discoveries	949	827	**1,776**	13.8	5.9	**19.7**	**142.0**
Purchase of reserves in place	63	211	**274**	0.2	–	**0.2**	**–**
Sale of reserves in place	(24)	(7)	**(31)**	(0.2)	–	**(0.2)**	**(398.0)** (4)
Production	(811)	(491)	**(1,302)**	(33.0)	(5.2)	**(38.2)**	**(10.8)**
End of year	7,292	6,008	**13,300**	273.4	58.3	**331.7**	**595.5**
Developed	4,868	3,368	**8,236**	217.8	37.0	**254.8**	**71.7**
Undeveloped	2,424	2,640	**5,064**	55.6	21.3	**76.9**	**523.8**
Total	7,292	6,008	**13,300**	273.4	58.3	**331.7**	**595.5**
2008							
Beginning of year	7,292	6,008	**13,300**	273.4	58.3	**331.7**	**595.5**
Revisions and improved recovery	148	(166)	**(18)**	27.9	(3.6)	**24.3**	**84.9**
Extensions and discoveries	1,311	655	**1,966**	17.0	3.8	**20.8**	**–**
Purchase of reserves in place	32	7	**39**	0.2	0.0	**0.2**	**–**
Sale of reserves in place	(129)	(75)	**(204)**	(0.9)	(2.0)	**(2.9)**	**–**
Production	(807)	(598)	**(1,405)**	(32.0)	(4.9)	**(36.9)**	**(12.0)**
End of year	7,847	5,831	**13,678**	285.6	51.6	**337.2**	**668.4**
Developed	4,945	3,720	**8,665**	208.5	33.9	**242.4**	**125.9**
Undeveloped	2,902	2,111	**5,013**	77.1	17.7	**94.8**	**542.5**
Total	7,847	5,831	**13,678**	285.6	51.6	**337.2**	**668.4**
2009 (5)							
Beginning of year	7,847	5,831	**13,678**	285.6	51.6	**337.2**	**668.4**
Revisions and improved recovery (6)	(755)	(845)	**(1,600)**	7.3	(12.6)	**(5.3)**	**(87.6)**
Extensions and discoveries	726	1,406	**2,132**	12.5	6.5	**19.0**	**159.4**
Purchase of reserves in place	28	–	**28**	0.5	–	**0.5**	**–**
Sale of reserves in place (7)	(1,772)	(89)	**(1,861)**	(243.2)	(0.2)	**(243.4)**	**(725.1)**
Production	(725)	(590)	**(1,315)**	(27.2)	(4.1)	**(31.3)**	**(15.1)**
End of year	5,349	5,713	**11,062**	35.5	41.2	**76.7**	**–**
Developed	2,927	3,571	**6,498**	25.1	25.8	**50.9**	**–**
Undeveloped	2,422	2,142	**4,564**	10.4	15.4	**25.8**	**–**
Total	5,349	5,713	**11,062**	35.5	41.2	**76.7**	**–**

Notes:

(1) Definitions:

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

b. "Proved" oil and gas reserves are those quantities of oil and gas which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. "Developed" oil and gas reserves are reserves of any category that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

d. "Undeveloped" oil and gas reserves are reserves of any category 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 natural gas and liquids reserves with any U.S. federal authority or agency other than the SEC.

(3) EnCana's disclosure of bitumen reserve volumes is in accordance with amended SEC rules regarding disclosure by final products. 2008 and 2007 crude oil and natural gas liquids totals have been revised to exclude bitumen volumes.

(4) Contribution of bitumen interests to the integrated oil business with ConocoPhillips.

(5) The estimates of reserves for the year-end 2009 differ from those that were determined in previous years, which were determined by employing year-end single day pricing. Single day prices as at December 31, 2009 were as follows: natural gas – Henry Hub $5.78/MMBtu and AECO C$5.63/MMBtu, which were approximately 49 percent higher than the 12-month average prices; crude oil – WTI $79.36/bbl and Edmonton Light C$82.69/bbl, which were approximately 30 percent and 26 percent higher than the 12-month average prices, respectively. The 2009 reserve estimates for natural gas and crude oil and natural gas liquids using the year-end single day pricing would have been higher by 11 percent and 7 percent respectively, than those reported pursuant to the amended SEC rules utilizing the 12-month average price.

(6) Revisions and improved recovery includes revisions due to price. Approximately 75 percent of the negative revisions to natural gas in 2009 were attributable to the significantly lower prices in effect for SEC reporting purposes.

(7) The transfer of EnCana's Canadian Plains and Integrated Oil Divisions upstream assets to Cenovus, effective November 30, 2009 by the Split Transaction, accounts for approximately 80 percent of the sale of reserves in place for natural gas and substantially all of the sale of reserves in place for crude oil and natural gas liquids and for bitumen.

Sensitivity of 2009 Reserves to Prices

The following table summarizes EnCana's estimates of its proved reserves as at December 31, 2009 based on the 2009 12-month average prices (SEC case) and on the prices set forth below.

	Natural Gas (billions of cubic feet)			Crude Oil and Natural Gas Liquids (millions of barrels)		
	Canada	United States	**Total**	Canada	United States	**Total**
Price Case						
SEC case	5,349	5,713	**11,062**	35.5	41.2	**76.7**
Business case	5,675	6,605	**12,280**	37.2	45.1	**82.3**
Difference versus SEC case	6.1%	15.6%	**11.0%**	4.9%	9.5%	**7.4%**

The business case assumes the following prices: natural gas – Henry Hub $5.50/MMBtu in 2010 and $6.50/MMBtu thereafter, and AECO C$5.49/MMBtu in 2010 and C$6.39/MMBtu in 2011 decreasing to C$6.04/MMBtu by 2014 and thereafter; crude oil – WTI $75.00/bbl and Edmonton Light C$76.84/bbl.

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

	Canada (1) (2)			United States (1)		
($ millions)	**2009**	2008	2007	**2009**	2008	2007
Future cash inflows	**19,321**	64,308	95,778	**18,573**	26,620	38,398
Less future:						
Production costs	**6,296**	23,017	25,089	**4,862**	6,079	5,869
Development costs	**4,065**	9,800	10,171	**4,429**	5,227	6,943
Asset retirement obligation payments	**1,508**	2,995	3,320	**640**	488	532
Income taxes	**659**	5,746	12,871	**707**	2,961	7,375
Future net cash flows	**6,793**	22,750	44,327	**7,935**	11,865	17,679
Less 10% annual discount for estimated timing of cash flows	**2,704**	10,036	21,663	**3,592**	5,218	8,196
Discounted future net cash flows	**4,089**	12,714	22,664	**4,343**	6,647	9,483

	Total (1)		
($ millions)	**2009**	2008	2007
Future cash inflows	**37,894**	90,928	134,176
Less future:			
Production costs	**11,158**	29,096	30,958
Development costs	**8,494**	15,027	17,114
Asset retirement obligation payments	**2,148**	3,483	3,852
Income taxes	**1,366**	8,707	20,246
Future net cash flows	**14,728**	34,615	62,006
Less 10% annual discount for estimated timing of cash flows	**6,296**	15,254	29,859
Discounted future net cash flows	**8,432**	19,361	32,147

(1) 2009 future net cash flows have been calculated using 12-month average prices of: natural gas – AECO C$3.77/MMBtu and Henry Hub $3.87/MMBtu; crude oil – WTI $61.18/bbl and Edmonton Light C$65.64/bbl. Future net cash flows would have been $18,453 million (Canada – $8,508 million; United States – $9,945 million) using the following single day December 31, 2009 prices: natural gas – AECO C$5.63/MMBtu and Henry Hub $5.78/MMBtu; crude oil – WTI $79.36/bbl and Edmonton Light C$82.69/bbl. In 2008 and 2007, future net cash flows were calculated using the December 31st period end price for the respective years.

(2) 2008 and 2007 future net cash flows included the cash flows from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These operations were transferred to Cenovus as part of the Split Transaction.

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

	Canada [1]			United States		
($ millions)	**2009**	2008	2007	**2009**	2008	2007
Balance, beginning of year	**12,714**	22,664	16,596	**6,647**	9,483	6,454
Changes resulting from:						
Sales of oil and gas produced during the period	**(5,609)**	(7,346)	(6,055)	**(3,442)**	(4,125)	(3,281)
Discoveries and extensions, net of related costs	**1,294**	2,031	3,632	**629**	904	1,591
Purchases of proved reserves in place	**16**	58	120	**–**	14	372
Sales and transfers of proved reserves in place	**(6,492)**	(321)	(1,283)	**(62)**	(197)	(15)
Net change in prices and production costs	**(1,825)**	(14,632)	9,671	**(1,446)**	(4,204)	4,818
Revisions to quantity estimates	**(1,242)**	1,736	603	**(1,567)**	667	830
Accretion of discount	**1,572**	2,905	2,087	**827**	1,346	924
Previously estimated development costs incurred net of change in future development costs	**737**	1,923	(259)	**1,474**	315	(907)
Other	**150**	321	(341)	**(26)**	88	(113)
Net change in income taxes	**2,774**	3,375	(2,107)	**1,309**	2,356	(1,190)
Balance, end of year	**4,089**	12,714	22,664	**4,343**	6,647	9,483

	Total		
($ millions)	**2009**	2008	2007
Balance, beginning of year	**19,361**	32,147	23,050
Changes resulting from:			
Sales of oil and gas produced during the period	**(9,051)**	(11,471)	(9,336)
Discoveries and extensions, net of related costs	**1,923**	2,935	5,223
Purchases of proved reserves in place	**16**	72	492
Sales and transfers of proved reserves in place	**(6,554)**	(518)	(1,298)
Net change in prices and production costs	**(3,271)**	(18,836)	14,489
Revisions to quantity estimates	**(2,809)**	2,403	1,433
Accretion of discount	**2,399**	4,251	3,011
Previously estimated development costs incurred net of change in future development costs	**2,211**	2,238	(1,166)
Other	**124**	409	(454)
Net change in income taxes	**4,083**	5,731	(3,297)
Balance, end of year	**8,432**	19,361	32,147

(1) Results prior to November 30, 2009 include reserves from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Results of Operations

($ millions)	Canada (1) 2009	2008	2007	United States 2009	2008	2007
Oil and gas revenues, net of royalties, transportation and selling costs	6,835	8,848	7,361	4,007	5,127	4,065
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,226	1,502	1,306	565	1,002	784
Depreciation, depletion and amortization	1,980	2,198	2,298	1,561	1,691	1,181
Operating income (loss)	3,629	5,148	3,757	1,881	2,434	2,100
Income taxes	1,059	1,502	1,114	698	937	809
Results of operations	2,570	3,646	2,643	1,183	1,497	1,291

($ millions)	Other 2009	2008	2007	Total 2009	2008	2007
Oil and gas revenues, net of royalties, transportation and selling costs	–	2	–	10,842	13,977	11,426
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	–	(2)	19	1,791	2,502	2,109
Depreciation, depletion and amortization	28	39	69	3,569	3,928	3,548
Operating income (loss)	(28)	(35)	(88)	5,482	7,547	5,769
Income taxes	–	–	–	1,757	2,439	1,923
Results of operations	(28)	(35)	(88)	3,725	5,108	3,846

(1) Results of Operations prior to November 30, 2009 include Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Capitalized Costs

($ millions)	Canada (1)			United States		
	2009	2008	2007	2009	2008	2007
Proved oil and gas properties	21,459	33,466	37,120	19,843	15,755	13,773
Unproved oil and gas properties	728	870	1,380	1,178	3,399	1,852
Total capital cost	22,187	34,336	38,500	21,021	19,154	15,625
Accumulated DD&A	11,586	17,348	19,286	7,092	5,511	3,783
Net capitalized costs	10,601	16,988	19,214	13,929	13,643	11,842

($ millions)	Other			Total		
	2009	2008	2007	2009	2008	2007
Proved oil and gas properties	–	–	–	41,302	49,221	50,893
Unproved oil and gas properties	157	122	305	2,063	4,391	3,537
Total capital cost	157	122	305	43,365	53,612	54,430
Accumulated DD&A	147	112	160	18,825	22,971	23,229
Net capitalized costs	10	10	145	24,540	30,641	31,201

(1) Results prior to November 30, 2009 include capitalized costs from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Costs Incurred

($ millions)	Canada (1)			United States		
	2009	2008	2007	2009	2008	2007
Acquisitions						
Unproved	46	32	28	46	1,006	1,048
Proved	178	119	61	–	17	1,565
Total acquisitions	224	151	89	46	1,023	2,613
Exploration costs	129	474	427	133	197	48
Development costs	2,588	3,485	3,214	1,688	2,485	1,887
Total costs incurred	2,941	4,110	3,730	1,867	3,705	4,548

($ millions)	Other			Total		
	2009	2008	2007	2009	2008	2007
Acquisitions						
Unproved	–	–	–	92	1,038	1,076
Proved	–	–	–	178	136	1,626
Total acquisitions	–	–	–	270	1,174	2,702
Exploration costs	2	14	60	264	685	535
Development costs	–	–	–	4,276	5,970	5,101
Total costs incurred	2	14	60	4,810	7,829	8,338

(1) Results prior to November 30, 2009 include costs incurred from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Supplemental Financial Information

The following Supplemental Information presents selected historical pro forma financial and operating information related to the ongoing operations of EnCana Corporation ("EnCana"). The information excludes the results of operations from assets distributed to Cenovus Energy Inc. as part of the Split Transaction.

For background on the pro forma information please refer to Note 1 – Basis of Presentation in the Notes to EnCana Pro Forma Consolidated Statements of Earnings and Cash from Operating Activities.

Pro Forma Consolidated Statement of Earnings (unaudited)

For the year ended December 31					2009	2008
($ millions, except per share amounts)	EnCana Consolidated	Deduct Cenovus Carve-out	Add/(Deduct) Pro Forma Adjustments	Note 2	**EnCana Pro Forma**	EnCana Pro Forma
Revenues, Net of Royalties	$ 11,114	$ 4,382	$		**$ 6,732**	$ 13,505
Expenses						
Production and mineral taxes	171	39			**132**	403
Transportation and selling	1,280	596			**684**	741
Operating	1,627	619			**1,008**	1,252
Purchased product	1,460	640			**820**	1,476
Depreciation, depletion and amortization	3,704	1,052	118	*A*	**2,770**	3,096
Administrative	477	108	41	*B*	**359**	329
			(51)	*C*		
Interest, net	405	34			**371**	368
Accretion of asset retirement obligation	71	34			**37**	40
Foreign exchange (gain) loss, net	(22)	290			**(312)**	673
(Gain) loss on divestitures	2	–			**2**	(143)
Net Earnings Before Income Tax	1,939	970	(108)		**861**	5,270
Income tax expense	109	393	396	*D i), ii),iii), iv)*	**112**	1,865
Net Earnings from Continuing Operations	1,830	577	(504)		**749**	3,405
Net Earnings from Discontinued Operations	32	32	–		**–**	–
Net Earnings	$ 1,862	$ 609	$ (504)		**$ 749**	$ 3,405
Net Earnings from Continuing Operations per Common Share				*E*		
Basic	$ 2.44				**$ 1.00**	$ 4.54
Diluted	$ 2.44				**$ 1.00**	$ 4.53
Net Earnings per Common Share				*E*		
Basic	$ 2.48				**$ 1.00**	$ 4.54
Diluted	$ 2.48				**$ 1.00**	$ 4.53

Pro Forma Consolidated Statement of Cash from Operating Activities (unaudited)

For the year ended December 31					2009	2008
($ millions)	EnCana Consolidated	Deduct Cenovus Carve-out	Add/(Deduct) Pro Forma Adjustments	*Note 2*	**EnCana Pro Forma**	EnCana Pro Forma
Operating Activities						
Net earnings from continuing operations	$ 1,830	$ 577	$ (504)		**$ 749**	$ 3,405
Depreciation, depletion and amortization	3,704	1,052	118	*A*	**2,770**	3,096
Future income taxes	(1,799)	(501)	860	*D i), ii), iii), iv)*	**(438)**	1,297
Cash tax on sale of assets	–	–			**–**	25
Unrealized (gain) loss on risk management	2,680	614			**2,066**	(1,995)
Unrealized foreign exchange (gain) loss	(231)	277			**(508)**	676
Accretion of asset retirement obligation	71	34			**37**	40
(Gain) loss on divestitures	2	–			**2**	(143)
Other	373	30			**343**	(47)
Cash flow from discontinued operations	149	149			**–**	–
Net change in other assets and liabilities	23	(15)			**38**	(173)
Net change in non-cash working capital from continuing operations	(29)	(11)			**(18)**	43
Net change in non-cash working capital from discontinued operations	1,100	1,100			**–**	–
Cash From Operating Activities	$ 7,873	$ 3,306	$ 474		**$ 5,041**	$ 6,224

Notes to Pro Forma Consolidated Statements of Earnings and Cash from Operating Activities (unaudited)

1. Basis of Presentation

On November 30, 2009, EnCana completed a corporate reorganization (the "Split Transaction") involving the division of EnCana into two independent publicly traded energy companies – EnCana and Cenovus Energy Inc. The unaudited Pro Forma Consolidated Statement of Earnings and Pro Forma Consolidated Statement of Cash from Operating Activities have been prepared for information purposes and assumes the Split Transaction occurred on January 1, 2008. Pro forma adjustments are detailed in Note 2.

The unaudited Pro Forma Consolidated Statement of Earnings and Pro Forma Consolidated Statement of Cash from Operating Activities are expressed in U.S. dollars and have been prepared for information purposes using information contained in the following:

a) EnCana's audited Consolidated Financial Statements for the years ended December 31, 2009 and 2008.

b) Cenovus Energy unaudited Carve-out Consolidated Financial Statements for the 11 months ended November 30, 2009 and the Cenovus Energy unaudited Carve-out Consolidated Financial Statements for the year ended December 31, 2008. The Cenovus unaudited Carve-out Consolidated Financial Statements were derived from the accounting records of EnCana on a carve-out basis.

c) EnCana's unaudited Pro Forma Consolidated Financial Statements for the year ended December 31, 2008.

In the opinion of Management of EnCana, the unaudited Pro Forma Consolidated Financial Statements include all the adjustments necessary for fair presentation in accordance with Canadian generally accepted accounting principles.

The unaudited Pro Forma Statement of Earnings and Pro Forma Consolidated Statement of Cash from Operating Activities are for illustrative purposes only and may not be indicative of the results that actually would have occurred if the Split Transaction had been in effect on the dates indicated or of the results that may be obtained in the future. In addition to the pro forma adjustments to the historical carve-out financial statements, various other factors will have an effect on the results of operations.

2. Pro Forma Assumptions and Adjustments

The following adjustments reflect expected changes to EnCana's historical results which would arise from the Split Transaction.

A. Reflects the expected difference in depreciation, depletion and amortization expense arising from a change in the depletion rate calculated for EnCana's Canadian cost centre.

B. Increases administrative expense for additional compensation costs arising from the separation of compensation plans and the estimated increase in the number of employees required to operate EnCana as a separate entity, after removing those costs associated with Cenovus's employees.

C. Reduces administrative expense to remove EnCana's share of the transaction costs incurred related to the Split Transaction.

D. Pro forma adjustments to income tax expense,

   i. adjustments for the tax effect of items A, B and C above;

   ii. adjustments for the effect of the loss of tax deferrals resulting from the wind up of EnCana's Canadian upstream oil and gas partnership;

   iii. acceleration of the intangible drilling costs deduction in the U.S. as a result of a change in the status of EnCana being considered an independent producer; and

   iv. remove tax benefits solely resulting from the Split Transaction.

E. The Pro Forma Net Earnings per Common Share is calculated using the same weighted average number of pre-Arrangement EnCana Corporation Common Shares outstanding as at December 31, 2009.

For the year ended December 31 (millions)	2009	2008
Weighted Average Common Shares Outstanding – Basic	751.0	750.1
Effects of Stock Options and Other Dilutive Securities	0.4	1.7
Weighted Average Common Shares Outstanding – Diluted	751.4	751.8

Supplemental Financial Information (unaudited)

Pro Forma Financial Statistics

($ millions, except per share amounts)	2009 Year	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Year	2008 Q4	2008 Q3	2008 Q2	2008 Q1
EnCana Pro Forma										
Cash Flow (1)	5,021	930	1,274	1,430	1,387	6,354	1,502	1,734	1,661	1,457
Per share – Diluted	6.68	1.24	1.70	1.90	1.85	8.45	2.00	2.31	2.21	1.93
Net Earnings	749	233	(53)	92	477	3,405	671	2,228	643	(137)
Per share – Diluted	1.00	0.31	(0.07)	0.12	0.63	4.53	0.89	2.97	0.86	(0.18)
Operating Earnings (2)	1,767	373	378	472	544	2,605	546	805	703	551
Per share – Diluted	2.35	0.50	0.50	0.63	0.72	3.47	0.73	1.07	0.94	0.73
Effective Tax Rates using										
Net Earnings	13.0%					35.4%				
Operating Earnings, excluding divestitures	28.7%					31.5%				
Canadian Statutory Rate	29.2%					29.7%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	0.876	0.947	0.911	0.857	0.803	0.938	0.825	0.961	0.990	0.996
Period end	0.956	0.956	0.933	0.860	0.794	0.817	0.817	0.944	0.982	0.973
Cash Flow Information										
Cash from Operating Activities	5,041	1,061	1,415	1,121	1,444	6,224	2,042	2,222	1,003	957
Deduct (Add back):										
Net change in other assets and liabilities	38	(5)	13	13	17	(173)	20	(10)	(124)	(59)
Net change in non-cash working capital from continuing operations	(18)	136	128	(322)	40	43	520	498	(534)	(441)
Cash Flow (1)	5,021	930	1,274	1,430	1,387	6,354	1,502	1,734	1,661	1,457

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital from continuing operations, both of which are defined on the Pro Forma Consolidated Statement of Cash from Operating Activities.

(2) 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 from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

	2009
Financial Metrics	
Debt to Capitalization (1)	32%
Debt to Adjusted EBITDA (1) (2)	2.1x
Return on Capital Employed (1) (2)	4%
Return on Common Equity (2)	5%

(1) Calculated using Debt defined as the current and long-term portions of Long-Term Debt.

(2) Calculated on a trailing 12-month basis.

Supplemental Financial Information (unaudited)

Pro Forma Net Capital Investment ($ millions)

	2009					2008				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Canadian Division	1,869	575	432	325	537	2,459	504	571	630	754
USA Division	1,821	515	358	374	574	2,682	854	645	669	514
	3,690	1,090	790	699	1,111	5,141	1,358	1,216	1,299	1,268
Market Optimization	–	–	–	1	(1)	1	–	–	1	–
Corporate & Other	65	37	4	13	11	113	30	28	33	22
Capital Investment	3,755	1,127	794	713	1,121	5,255	1,388	1,244	1,333	1,290
Acquisitions										
Property										
Canadian Division	190	108	8	1	73	151	31	28	20	72
USA Division	46	25	7	8	6	1,023	(71)	850	258	(14)
Corporate										
Canadian Division (1)	24	–	–	24	–	–	–	–	–	–
Divestitures										
Property										
Canadian Division	(1,000)	(43)	(913)	(11)	(33)	(400)	(182)	(148)	(9)	(61)
USA Division	(73)	(3)	(66)	(4)	–	(251)	(128)	(28)	(91)	(4)
Corporate & Other	(2)	–	–	(2)	–	(41)	–	(94)	29	24
Corporate										
Corporate & Other (2)	–	–	–	–	–	(165)	(1)	(164)	–	–
Net Acquisition and Divestiture Activity	(815)	87	(964)	16	46	317	(351)	444	207	17
Net Capital Investment	2,940	1,214	(170)	729	1,167	5,572	1,037	1,688	1,540	1,307

(1) Acquisition of Kerogen Resources Canada, ULC on May 5, 2009.

(2) In 2008, the sale of interests in Brazil was completed on September 18, 2008.

Pro Forma Production Volumes

	2009					2008				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*										
Canadian Division (1)	1,224	1,071	1,201	1,343	1,281	1,300	1,302	1,351	1,289	1,256
USA Division	1,616	1,616	1,524	1,581	1,746	1,633	1,677	1,674	1,629	1,552
Total Produced Gas	2,840	2,687	2,725	2,924	3,027	2,933	2,979	3,025	2,918	2,808
Liquids *(bbls/d)*										
Canadian Division (1)	15,880	12,477	15,909	17,624	17,567	19,980	19,702	19,947	20,155	20,123
USA Division	11,317	11,586	10,325	11,699	11,671	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	27,197	24,063	26,234	29,323	29,238	33,330	32,533	33,800	33,637	33,355
Total *(MMcfe/d)*	3,003	2,831	2,883	3,100	3,203	3,132	3,174	3,227	3,120	3,008

(1) Formerly known as the Canadian Foothills Division.

Supplemental Oil and Gas Operating Statistics (unaudited)

Operating Statistics – After Royalties

Pro Forma Per-unit Results (1)
(excluding impact of realized financial hedging)

	2009					2008				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas – Canadian Division *($/Mcf)*										
Price	3.71	4.21	2.92	3.19	4.58	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	0.03	–	0.02	0.04	0.03	0.06	0.03	0.09	0.09	0.03
Transportation and selling	0.33	0.40	0.35	0.30	0.30	0.42	0.37	0.43	0.43	0.47
Operating	1.13	1.43	1.09	1.02	1.04	1.15	0.98	0.87	1.39	1.41
Netback	2.22	2.38	1.46	1.83	3.21	6.49	4.49	7.64	8.03	5.70
Produced Gas – USA Division *($/Mcf)*										
Price	3.75	4.64	3.41	3.01	3.88	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	0.17	0.23	0.08	0.08	0.27	0.56	0.35	0.56	0.72	0.62
Transportation and selling	0.90	0.96	0.99	0.87	0.78	0.84	0.87	0.86	0.81	0.81
Operating	0.55	0.61	0.56	0.54	0.51	0.59	0.56	0.38	0.71	0.71
Netback	2.13	2.84	1.78	1.52	2.32	5.90	3.23	6.74	7.69	6.05
Produced Gas – Total *($/Mcf)*										
Price	3.73	4.47	3.19	3.09	4.18	7.99	5.39	8.76	9.93	7.93
Production and mineral taxes	0.11	0.14	0.06	0.06	0.17	0.34	0.21	0.35	0.44	0.36
Transportation and selling	0.66	0.74	0.71	0.61	0.58	0.66	0.65	0.67	0.64	0.66
Operating	0.80	0.93	0.79	0.76	0.74	0.84	0.74	0.60	1.01	1.02
Netback	2.16	2.66	1.63	1.66	2.69	6.15	3.79	7.14	7.84	5.89
Liquids – Canadian Division *($/bbl)*										
Price	47.86	60.37	52.48	45.86	36.51	85.12	44.37	102.60	106.65	86.37
Production and mineral taxes	0.45	0.34	0.48	0.47	0.47	0.63	0.48	0.68	0.85	0.51
Transportation and selling	1.06	0.49	1.41	0.62	1.61	1.64	1.42	1.58	2.13	1.43
Operating	3.62	3.25	3.04	4.09	3.94	5.41	5.00	4.13	6.39	6.11
Netback	42.73	56.29	47.55	40.68	30.49	77.44	37.47	96.21	97.28	78.32
Liquids – USA Division *($/bbl)*										
Price	48.56	64.39	55.60	47.27	27.43	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	4.39	5.84	5.12	4.18	2.48	7.25	3.79	8.19	9.75	7.13
Transportation and selling	–	–	–	–	–	–	–	–	–	–
Netback	44.17	58.55	50.48	43.09	24.95	75.93	41.60	89.44	95.98	75.09
Total Liquids *($/bbl)*										
Price	48.15	62.31	53.71	46.42	32.88	84.38	44.78	100.56	106.23	84.79
Production and mineral taxes	2.09	2.99	2.31	1.95	1.27	3.27	1.78	3.76	4.39	3.11
Transportation and selling	0.62	0.26	0.85	0.38	0.96	0.98	0.86	0.93	1.28	0.86
Operating	2.11	1.68	1.84	2.46	2.37	3.40	3.03	2.44	4.06	4.08
Netback	43.33	57.38	48.71	41.63	28.28	76.73	39.11	93.43	96.50	76.74

Supplemental Oil and Gas Operating Statistics (unaudited)

Operating Statistics – After Royalties (continued)

Pro Forma Per-unit Results [1]
(excluding impact of realized financial hedging)

	2009					2008				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Netback – Canadian Division *($/Mcfe)*										
Price	**4.02**	**4.59**	3.36	3.51	4.70	8.63	6.00	9.69	10.61	8.21
Production and mineral taxes	**0.03**	**0.01**	0.02	0.04	0.04	0.06	0.03	0.09	0.09	0.04
Transportation and selling	**0.32**	**0.38**	0.34	0.28	0.30	0.41	0.36	0.42	0.42	0.45
Operating	**1.09**	**1.37**	1.05	0.99	1.01	1.13	0.97	0.86	1.36	1.37
Netback	**2.58**	**2.83**	1.95	2.20	3.35	7.03	4.64	8.32	8.74	6.35
Total Netback – USA Division *($/Mcfe)*										
Price	**3.92**	**4.89**	3.64	3.21	3.91	8.17	5.12	8.91	10.29	8.46
Production and mineral taxes	**0.19**	**0.26**	0.11	0.10	0.28	0.59	0.36	0.60	0.76	0.65
Transportation and selling	**0.86**	**0.92**	0.95	0.83	0.75	0.80	0.83	0.82	0.78	0.77
Operating	**0.53**	**0.58**	0.54	0.52	0.49	0.56	0.53	0.37	0.68	0.68
Netback	**2.34**	**3.13**	2.04	1.76	2.39	6.22	3.40	7.12	8.07	6.36
Total Netback *($/Mcfe)*										
Price	**3.96**	**4.77**	3.51	3.35	4.25	8.38	5.51	9.26	10.44	8.35
Production and mineral taxes	**0.12**	**0.16**	0.07	0.08	0.17	0.35	0.21	0.37	0.46	0.37
Transportation and selling	**0.63**	**0.70**	0.68	0.58	0.56	0.62	0.62	0.64	0.62	0.62
Operating [2]	**0.78**	**0.90**	0.76	0.74	0.72	0.82	0.73	0.59	0.99	1.00
Netback	**2.43**	**3.01**	2.00	1.95	2.80	6.59	3.95	7.66	8.37	6.36

(1) EnCana consolidated per-unit results excluding Cenovus carve-out per-unit results.

(2) 2009 operating costs include costs related to long-term incentives of $0.03/Mcfe (2008 – recovery of costs of $0.01/Mcfe).

Pro Forma Impact of Realized Financial Hedging [1]

	2009					2008				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	**3.30**	**1.97**	4.25	3.93	3.04	0.07	1.94	(0.69)	(1.25)	0.25
Liquids *($/bbl)*	**(0.01)**	**–**	–	–	(0.03)	(3.65)	1.14	(5.43)	(6.70)	(3.45)
Total *($/Mcfe)*	**3.12**	**1.87**	4.02	3.70	2.87	0.03	1.84	(0.71)	(1.24)	0.20

(1) EnCana consolidated impact of realized hedging excluding Cenovus carve-out impact of realized financial hedging.

Supplemental Financial Information (unaudited)

Financial Statistics

($ millions, except per share amounts)		2009					2008				
		Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Pro Forma Reconciliation											
Cash Flow (1)											
EnCana Corporation, Consolidated		**6,779**	**603**	2,079	2,153	1,944	9,386	1,299	2,809	2,889	2,389
Less: Cenovus Carve-out (2)		**2,232**	**(15)**	841	811	595	3,088	(174)	1,123	1,228	911
Add/(Deduct) Pro Forma adjustments		**474**	**312**	36	88	38	56	29	48	–	(21)
EnCana Pro Forma		**5,021**	**930**	1,274	1,430	1,387	6,354	1,502	1,734	1,661	1,457
Per share amounts											
EnCana Corporation, Consolidated	– Basic	**9.03**	**0.80**	2.77	2.87	2.59	12.51	1.73	3.74	3.85	3.19
	– Diluted	**9.02**	**0.80**	2.77	2.87	2.59	12.48	1.73	3.74	3.85	3.17
EnCana Pro Forma	– Basic	**6.69**	**1.24**	1.70	1.90	1.85	8.47	2.00	2.31	2.21	1.94
	– Diluted	**6.68**	**1.24**	1.70	1.90	1.85	8.45	2.00	2.31	2.21	1.93
Net Earnings											
EnCana Corporation, Consolidated		**1,862**	**636**	25	239	962	5,944	1,077	3,553	1,221	93
Less: Cenovus Carve-out (2)		**609**	**(15)**	63	149	412	2,368	380	1,299	522	167
Add/(Deduct) Pro Forma adjustments		**(504)**	**(418)**	(15)	2	(73)	(171)	(26)	(26)	(56)	(63)
EnCana Pro Forma		**749**	**233**	(53)	92	477	3,405	671	2,228	643	(137)
Per share amounts											
EnCana Corporation, Consolidated	– Basic	**2.48**	**0.85**	0.03	0.32	1.28	7.92	1.44	4.74	1.63	0.12
	– Diluted	**2.48**	**0.85**	0.03	0.32	1.28	7.91	1.43	4.73	1.63	0.12
EnCana Pro Forma	– Basic	**1.00**	**0.31**	(0.07)	0.12	0.64	4.54	0.89	2.97	0.86	(0.18)
	– Diluted	**1.00**	**0.31**	(0.07)	0.12	0.63	4.53	0.89	2.97	0.86	(0.18)
Operating Earnings (3)											
EnCana Corporation, Consolidated		**3,495**	**855**	775	917	948	4,405	449	1,442	1,469	1,045
Less: Cenovus Carve-out (2)		**1,224**	**64**	382	447	331	1,629	(123)	611	710	431
Add/(Deduct) Pro Forma adjustments		**(504)**	**(418)**	(15)	2	(73)	(171)	(26)	(26)	(56)	(63)
EnCana Pro Forma		**1,767**	**373**	378	472	544	2,605	546	805	703	551
Per share amounts											
EnCana Corporation, Consolidated	– Diluted	**4.65**	**1.14**	1.03	1.22	1.26	5.86	0.60	1.92	1.96	1.39
EnCana Pro Forma	– Diluted	**2.35**	**0.50**	0.50	0.63	0.72	3.47	0.73	1.07	0.94	0.73

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, which are defined on the Consolidated Statement of Cash Flows.

(2) Cenovus Energy was spun-off on November 30, 2009. As a result, carve-out information for the fourth quarter is for the two months ended November 30, 2009 and the Year-to-date information is for the 11 months ended November 30, 2009.

(3) 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 from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Drilling Activity (unaudited)

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

Exploration Wells Drilled [(1) (2)]

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	**Gross**	**Net**
2009											
Canadian Division	**34**	**24**	**1**	**1**	**–**	**–**	**35**	**25**	**25**	**60**	**25**
USA Division	**8**	**4**	**–**	**–**	**1**	**–**	**9**	**4**	**–**	**9**	**4**
	42	**28**	**1**	**1**	**1**	**–**	**44**	**29**	**25**	**69**	**29**
Canada – Other (3)	**–**	**–**	**4**	**4**	**–**	**–**	**4**	**4**	**8**	**12**	**4**
Other	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Total	**42**	**28**	**5**	**5**	**1**	**–**	**48**	**33**	**33**	**81**	**33**
2008											
Canadian Division	70	54	8	5	–	–	78	59	69	147	59
USA Division	26	14	–	–	–	–	26	14	–	26	14
	96	68	8	5	–	–	104	73	69	173	73
Canada – Other (3)	5	3	1	1	2	1	8	5	34	42	5
Other	–	–	–	–	3	1	3	1	–	3	1
Total	101	71	9	6	5	2	115	79	103	218	79
2007											
Canadian Division	116	92	4	3	–	–	120	95	91	211	95
USA Division	2	2	–	–	–	–	2	2	–	2	2
	118	94	4	3	–	–	122	97	91	213	97
Canada – Other (3)	4	4	3	3	–	–	7	7	89	96	7
Other	–	–	–	–	4	3	4	3	–	4	3
Total	122	98	7	6	4	3	133	107	180	313	107

(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) Includes wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These assets were transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Development Wells Drilled (1) (2)

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	**Gross**	**Net**
2009 (3)											
Canadian Division	**731**	**672**	**3**	**2**	**–**	**–**	**734**	**674**	**143**	**877**	**674**
USA Division	**495**	**382**	**–**	**–**	**5**	**4**	**500**	**386**	**55**	**555**	**386**
	1,226	**1,054**	**3**	**2**	**5**	**4**	**1,234**	**1,060**	**198**	**1,432**	**1,060**
Canada – Other (4)	**560**	**507**	**144**	**120**	**8**	**8**	**712**	**635**	**255**	**967**	**635**
Total	**1,786**	**1,561**	**147**	**122**	**13**	**12**	**1,946**	**1,695**	**453**	**2,399**	**1,695**
2008											
Canadian Division	1,088	989	17	16	–	–	1,105	1,005	329	1,434	1,005
USA Division	904	736	–	–	–	–	904	736	378	1,282	736
	1,992	1,725	17	16	–	–	2,009	1,741	707	2,716	1,741
Canada – Other (4)	1,502	1,385	146	113	11	11	1,659	1,509	544	2,203	1,509
Total	3,494	3,110	163	129	11	11	3,668	3,250	1,251	4,919	3,250
2007											
Canadian Division	1,528	1,425	20	18	1	1	1,549	1,444	325	1,874	1,444
USA Division	809	641	–	–	1	1	810	642	36	846	642
	2,337	2,066	20	18	2	2	2,359	2,086	361	2,720	2,086
Canada – Other (4)	2,221	2,117	216	167	10	7	2,447	2,291	509	2,956	2,291
Total	4,558	4,183	236	185	12	9	4,806	4,377	870	5,676	4,377

(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, 2009, EnCana was in the process of drilling the following exploratory and development wells: approximately five gross wells (five net wells) in Canada and approximately 60 gross wells (48 net wells) in the U.S.

(4) Includes wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These assets were transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Land (unaudited)

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2009.

	Gas		Oil		**Total** (1) (2)	
(number of wells)	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta	10,814	9,759	398	225	**11,212**	**9,984**
British Columbia	2,133	1,980	15	11	**2,148**	**1,991**
Total Canada	12,947	11,739	413	236	**13,360**	**11,975**
Colorado	5,107	4,482	6	2	**5,113**	**4,484**
Texas	1,894	1,318	36	25	**1,930**	**1,343**
Wyoming	2,067	1,537	1	1	**2,068**	**1,538**
Utah	40	37	11	11	**51**	**48**
Louisiana	76	47	–	–	**76**	**47**
Kansas	1	1	–	–	**1**	**1**
Montana	1	1	–	–	**1**	**1**
Total United States	9,186	7,423	54	39	**9,240**	**7,462**
Total	22,133	19,162	467	275	**22,600**	**19,437**

(1) EnCana has varying royalty interests in approximately 8,216 natural gas wells and approximately 5,480 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: approximately 11,155 gross natural gas wells (1,744 net wells) and approximately 146 gross crude oil wells (92 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2009.

Landholdings (1) (2) (3) (4) (5) (6)		Developed		Undeveloped		Total	
(thousands of acres)		Gross	Net	Gross	Net	Gross	Net
Canada							
Alberta	– Fee	2,467	2,467	1,611	1,611	4,078	4,078
	– Crown	1,312	741	1,394	1,098	2,706	1,839
	– Freehold	222	127	74	55	296	182
		4,001	3,335	3,079	2,764	7,080	6,099
British Columbia	– Crown	1,024	910	2,807	2,201	3,831	3,111
	– Freehold	–	–	7	–	7	–
		1,024	910	2,814	2,201	3,838	3,111
Newfoundland and Labrador	– Crown	–	–	35	2	35	2
Nova Scotia	– Crown	–	–	41	30	41	30
Northwest Territories	– Crown	–	–	45	12	45	12
Total Canada		5,025	4,245	6,014	5,009	11,039	9,254
United States							
Colorado	– Federal/State Lands	197	183	615	561	812	744
	– Freehold	105	96	131	120	236	216
	– Fee	3	3	31	31	34	34
		305	282	777	712	1,082	994
Texas	– Federal/State Lands	7	4	67	65	74	69
	– Freehold	229	170	987	793	1,216	963
	– Fee	–	–	4	2	4	2
		236	174	1,058	860	1,294	1,034
Wyoming	– Federal/State Lands	142	83	473	343	615	426
	– Freehold	15	8	28	15	43	23
		157	91	501	358	658	449
Louisiana	– Federal/State Lands	–	–	4	4	4	4
	– Freehold	28	16	514	325	542	341
	– Fee	13	11	75	51	88	62
		41	27	593	380	634	407
Other	– Federal/State Lands	9	8	342	329	351	337
	– Freehold	1	1	257	238	258	239
	– Fee	–	–	–	–	–	–
		10	9	599	567	609	576
Total United States		749	583	3,528	2,877	4,277	3,460
International							
Greenland		–	–	1,700	808	1,700	808
Azerbaijan		–	–	346	17	346	17
Australia		–	–	104	40	104	40
Total International		–	–	2,150	865	2,150	865
Total		5,774	4,828	11,692	8,751	17,466	13,579

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

(2) This table excludes approximately 2.9 million gross acres of fee lands with one or more substances or products under lease or sublease, reserving to EnCana royalties or other interests.

(3) Crown/Federal/State lands are those owned by the federal, provincial or state government or the First Nations, in which EnCana has purchased a working interest lease.

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

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

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

ABBREVIATIONS

bbls	barrels
bbl/d	barrels per day
BOE	barrels of oil equivalent
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
CBM	coalbed methane
CNG	compressed natural gas
CO_2	carbon dioxide
EBITDA	earnings before interest, taxes, depreciation and amortization
CH_4	methane
LNG	liquefied natural gas
LPG	liquid petroleum gas
Mbbls	thousand barrels
Mbbls/d	thousand barrels per day
MMbbls	million barrels
MMbbls/d	million barrels per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MM	million
MMcf	million cubic feet
MMcfe	million cubic feet equivalent
MMcfe/d	million cubic feet equivalent per day
NGL	natural gas liquids
NOx	nitrogen oxides
SO_2	sulphur dioxide
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent
/d	per day

ENDNOTES

NATURAL GAS: THE FUEL FOR THE 21ST CENTURY / PAGES 24-26

1. Information Handling Services (IHS)
2. Encana estimate
3. United States Energy Information Administration (EIA); Statistics Canada; Encana estimate
4. Encana estimate
5. cngprices.com; gasbuddy.com
6. PGC 2009; Encana estimate
7. www.brittanica.com/EBchecked/topic/336021/Etienne-Lenoir
8. Randomhistory.com
9. International Association for Natural Gas Vehicles
10. International Association for Natural Gas Vehicles
11. Cartalk.com
12. EIA
13. EIA; Encana estimate
14. EIA
15. EIA; Encana estimate
16. EIA; Encana estimate
17. EIA; Encana estimate

WHY INVEST IN ENCANA NOW / PAGES 11-13

1. Cautionary statement: Estimates of contingent natural gas resources are by their nature uncertain. There is no certainty that it will be commercially viable to produce any portion of the resources.

NG 101 / NATURAL GAS END USE / INSERT

1. United States Energy Information Administration (EIA); Encana estimates
2. EIA
3. Sempra LNG; EIA
4. EIA
5. Encana estimate
6. IHS Insights; CERI
7. EIA; Statistics Canada; Encana estimates
8. EIA; Encana estimate
9. EIA; Encana estimate
10. EIA; Statistics Canada; Encana estimate
11. IHS; Encana estimate
12. IHS; Encana estimate
13. International Association for Natural Gas Vehicles
14. Clean Vehicle Education Foundation
15. Potential Gas Committee (PGC); Encana estimate
16. EIA; Encana estimate
17. EIA; Encana estimate
18. EIA; Encana estimate
19. EIA; Encana estimate
20. EIA; Encana estimate

DISCLOSURE RELATING TO FORWARD-LOOKING INFORMATION AND MATERIAL ASSUMPTIONS:

Forward-looking information with respect to anticipated production, reserves and company size growth, including over the next five years, is based upon numerous facts and assumptions which are discussed in further detail in this Annual Report, including Encana's current net drilling location inventory, long-term natural gas marginal supply costs, long-term natural gas price expectations, production expectations made in light of advancements in horizontal drilling, multi-stage hydraulic fracture stimulation and multi-well pad drilling, the current and expected productive characteristics of various existing and emerging resource plays, Encana's estimates of proved reserves, probable reserves, possible reserves and economic contingent resources, expectations for rates of return, which may be available at various prices for natural gas and current, expected cost trends and facts and trends which may increase demand for natural gas. In addition, assumptions relating to such forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

ANNUAL AND SPECIAL MEETING

Shareholders are invited to attend the Meeting being held on Wednesday, April 21, 2010 at 2 p.m. local time at:

Calgary TELUS Convention Centre, Macleod Hall, Lower Level, South Building, 120 9 Avenue S.E., Calgary, Alberta, Canada

Those unable to do so are asked to sign and return the form of proxy mailed to them.

CORPORATE INFORMATION

TRANSFER AGENTS & REGISTRAR

Common Shares
CIBC Mellon Trust Company
Calgary, Montreal & Toronto

BNY Mellon Shareowner Services
Jersey City, New Jersey

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding security holdings. CIBC can be reached via the Answerline at 416-643-5990 or toll-free throughout North America at 1-866-580-7145, or via facsimile at 416-643-5501.

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AUDITORS

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

DeGolyer and MacNaughton
Dallas, Texas

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGES

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

INVESTOR INFORMATION

ANNUAL INFORMATION FORM (AIF) (FORM 40-F)

Encana's 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

www.encana.com

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 Circulars
- News releases
- Investor presentations
- Dividend information
- Dividend reinvestment plan
- Shareholder support information
- Corporate Responsibility information

Additional information, including copies of the ENCANA CORPORATION 2009 Annual Report, may be obtained from:

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NATURAL GAS / THE CLEAR ENERGY CHOICE

ENCANA / DVD

Imagine a world fuelled by natural gas…a world with fewer CO_2 emissions, fewer smog-creating pollutants and cleaner, healthier air. Imagine reducing North America's carbon footprint by about 30 percent.

Can you imagine the future? Encana can. We've been working hard to ensure a reliable supply of clean-burning energy for decades to come. Natural gas is secure, affordable and abundant…and we can produce it in North America for North Americans. Imagine. Natural gas is the clear energy choice.

Encana / REGISTERED SHAREHOLDERS

Watch for your proxy package, which is mailed separately from this report. In it, you will find a form to complete and return to CIBC Mellon opting you out of a printed copy of our next annual report. Make sure you send it by April 30, 2010, and Encana will buy a one ton carbon emission offset on your behalf.


Greenhouse gas emissions are so last century.
We are converting 30 percent of our vehicles in the southern Rockies so that they can run on natural gas. We're doing this, quite frankly, because it's good for the environment and it's good for business. We are Encana.
encana
natural gas
Learn more about natural gas and Encana at www.encana.com


The clear energy choice.
Natural gas.
We believe in natural gas. We believe it's the fuel for the 21st century. For power generation. For vehicle fuel. As a domestic energy solution. Most important – to lower emissions. We figure that's something worth talking about. **We are Encana.**
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natural gas
Learn more about natural gas and Encana at **www.encana.com**