THE CENOVUS EQUATION

2010 ANNUAL REPORT

WE ARE A CANADIAN OIL COMPANY APPLYING FRESH, PROGRESSIVE THINKING:

To safely and responsibly unlock energy resources the world needs – that's our promise.
To increase total shareholder return – that's our goal.

Pictured here is Foster Creek, our largest steam-assisted gravity drainage (SAGD) project, situated on the Cold Lake Air Weapons Range in northern Alberta.


SEE HOW WE ADD UP

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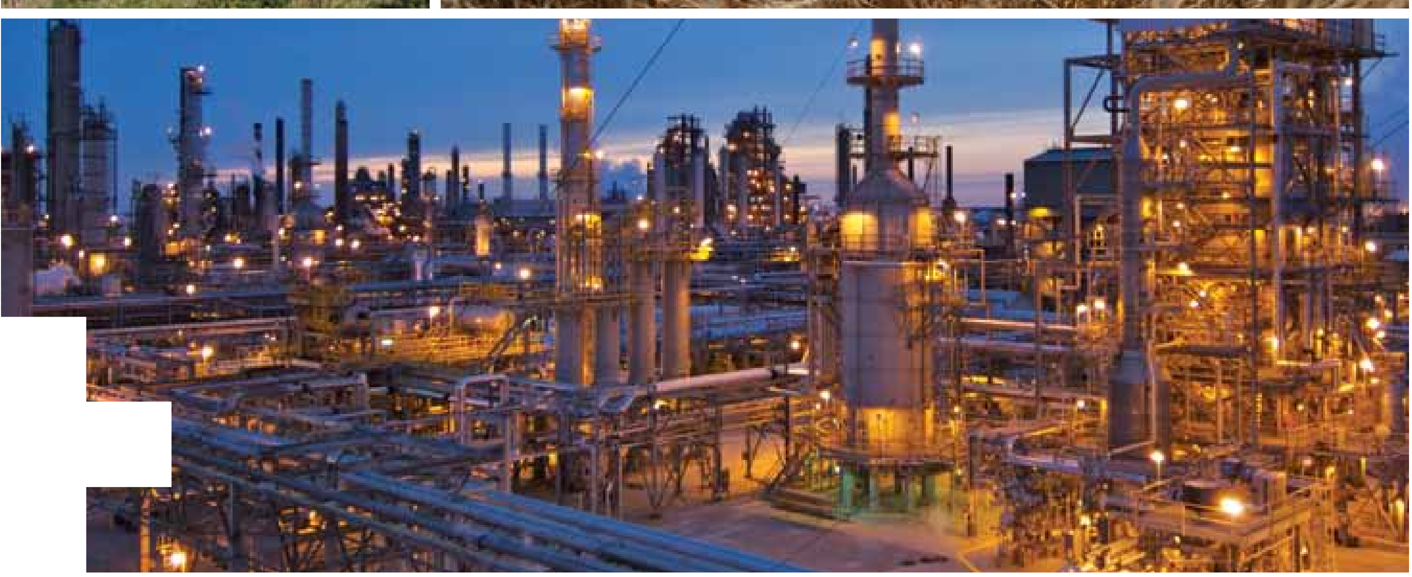
OUR ABILITY TO ACHIEVE OUR PROMISE AND OUR GOAL REQUIRES A GREAT ASSET BASE AND THE RIGHT PEOPLE DOING THE RIGHT THINGS. WE HAVE BOTH. THE CENOVUS EQUATION SHOWS HOW WE ADD UP.

THIS PAGE We grow our oil sands projects in phases. Construction is currently underway for phases C and D at Christina Lake. Phase C, a 40,000 barrel-per-day expansion is expected to be completed in 2011. FACING PAGE The majority of Cenovus's natural gas production comes from our shallow gas operations in southern Alberta. Pictured here is a drilling rig near Brooks.


TO RESULTS

OUR GREAT ASSETS PROVIDE THE FOUNDATION FOR YEARS OF ENERGY DEVELOPMENT.

We have an industry-leading portfolio of oil sands assets, two high-quality refining assets, a strong balance sheet, and low-cost conventional oil and natural gas operations that generate substantial operating cash flow.



THIS PAGE (CLOCKWISE) A pumpjack at our Weyburn facility in Saskatchewan / A natural gas wellhead near Brooks, Alberta / The Wood River Refinery in Roxanna, Illinois jointly owned with ConocoPhillips. FACING PAGE We're always looking for ways to improve how we get our resources out of the ground. Pictured here is equipment used for the solvent aided process (SAP) at Christina Lake. SAP is a technology we're piloting. It helps maximize the amount of oil recovered using SAGD while reducing the environmental impact.

QUALITY RESOURCES + FINANCIAL STRENGTH = **GREAT ASSETS**

WE TAKE OUR COMMITMENT TO SMART RESOURCE DEVELOPMENT SERIOUSLY. WE AIM TO MAXIMIZE VALUE FOR OUR SHAREHOLDERS WHILE SEEKING TO BALANCE ECONOMIC, SOCIAL AND ENVIRONMENTAL PERFORMANCE.

This commitment guides the way we conduct our operations and is the foundation of our 10-year business plan.

THIS PAGE (CLOCKWISE) Speaking with a landowner / A Cenovus employee taking water samples / Oil storage pipe racks coated with fire proofing leaving our module fabrication yard in Nisku for our Christina Lake facility. FACING PAGE Our environmental specialists inspect and analyze the land we'll be using for our drilling activities before any operations begin. They then develop a plan that will reclaim the land once a well is depleted. Pictured here is new growth in the forest near our Foster Creek project.


STRONG EXECUTION + RESPONSIBLE OPERATIONS = SMART RESOURCE DEVELOPMENT

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WE HAVE A CULTURE THAT FOSTERS NEW IDEAS AND NEW APPROACHES IN ALL ASPECTS OF OUR BUSINESS.

In our operations, technology plays a key role in extracting the resources – enhancing the amount recovered and improving the methods we use to get the oil and natural gas out of the ground. An ongoing objective is to advance innovative technologies that reduce the amount of land, water and energy we use.

THIS PAGE (CLOCKWISE) Foster Creek control room / Building a culture of knowledge sharing through staff information sessions / Solar panels in some of our operations provide power to remote instruments, allowing for data communication back to our main facility / Staff at our Weyburn facility. FACING PAGE The plants at our oil sands facilities are largely water plants that require a complex system of pipes to transport steam and fluids used in the SAGD process. Pictured here is our Christina Lake facility.

INNOVATION + CONTINUOUS IMPROVEMENT = **LEADING TECHNOLOGY**

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WE HAVE YEARS OF EXPERIENCE IMPROVING WHAT WE DO. A TRACK RECORD OF DELIVERING GREAT PERFORMANCE. A PASSION FOR RESULTS.

The people at Cenovus are dedicated and enthusiastic about improving every aspect of our business. Experienced in turning ideas into action, and committed to doing right by the environment and our communities. We are proud to have the right people doing the right things to provide the energy resources the world needs and relies on every day.

THIS PAGE (CLOCKWISE) Adjusting a bolt on a pumpjack in Langevin / Cenovus staff in a meeting / Operators at Christina Lake.
FACING PAGE At Cenovus it's important our equipment is operating at an optimal level. Our employees are always looking for ways to improve equipment reliability and performance. Pictured here is a mechanic at our Weyburn facility completing preventative maintenance on mechanical components.

KNOWLEDGE + DEDICATION = THE RIGHT PEOPLE

Our people bring energy, focus and dedication to their work.
Pictured here is an operator at Christina Lake.

GREAT ASSETS

✚ SMART RESOURCE DEVELOPMENT

✚ LEADING TECHNOLOGY

✚ THE RIGHT PEOPLE

= **CENOVUS**

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As a company we are: Rigorous. Respectful. Ready. We have the resource, the strategy and a track record of strong results. As a team, we have the passion for operational excellence, the commitment to finding better ways of doing things and respect for the environment and the communities where we live and work. That's how we add up to results.

Operating adjustments may be required to ensure our treated oil meets pipeline sales specifications before it's shipped to market. Pictured here is an operator conducting oil sampling at Foster Creek.

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FCCL/WRB Partnership Our business venture with ConocoPhillips provides integration of oil sands and refining operations. This venture provides Cenovus with a 50 percent interest in the Wood River (Illinois) and Borger (Texas) refineries; in return ConocoPhillips has a 50 percent interest in certain Cenovus oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake. For additional information, see our MD&A.

Forward-looking information Our Annual Report contains forward-looking information about our strategy, milestones, goals, targets and future expectations. This forward-looking information is based on certain factors and assumptions and is subject to risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. For details about these factors, assumptions, risks and uncertainties, please refer to the Advisory section in our MD&A. All estimated timelines are subject to regulatory and/or partner approval. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied. For an overview of our risk management, see the Risk Management section of our MD&A.

Non-GAAP measures Our Annual Report contains references to certain financial measures which do not have a standardized meaning as prescribed by GAAP. A description of each non-GAAP measure, including a definition and reconciliation with GAAP measures, is included in our MD&A.

Oil and Gas information Our Annual Report contains information about our reserves and our bitumen resources. For additional information about our reserves, contingent and prospective resources, see the Oil and Gas Reserves and Resources section of our MD&A and the Advisory section of our MD&A. For additional information about our total and discovered bitumen initially-in-place, see the Additional Advisory on page 132.

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Increasing total return to our shareholders is the cornerstone of our 10-year business plan. With our high-quality oil opportunities, our track record of strong execution and our financial strength, we plan to achieve increased shareholder return in two ways:

NAV is a comprehensive measure well suited to the long-term nature of oil sands development.

DOUBLE NAV* BY 2015

&

PAY A STRONG AND SUSTAINABLE DIVIDEND

INCREASE OIL SANDS PRODUCTION

FROM 60 THOUSAND BBLS/D† IN 2010

TO 300 THOUSAND BBLS/D† IN 2019

MAINTAIN STRONG PERFORMANCE FROM CONVENTIONAL OIL AND NATURAL GAS ASSETS

We plan to maintain financial flexibility and optimize cash flow to grow our business and provide an income stream to shareholders.

* NAV: Net asset value (total value of assets minus total value of liabilities)
† Net to Cenovus

We plan to double net asset value and pay a strong and sustainable dividend by leveraging these three strategic advantages:

OIL OPPORTUNITIES

BARRELS OF DISCOVERED BIIP*
56
BILLION
AMOUNT DEFINED THROUGH DRILLING

Vast majority of our total proved + probable reserves are bitumen, conventional oil and NGLs** – 88% of 2.4 billion barrels of oil equivalent.

GROWTH DRIVER: OIL

Increasing contribution to upstream operating cash flow from oil and NGLs.
2010: 63% **2019**F: 80%

Goal: increase oil sands production five-fold by the end of 2019 by:

- converting resources into reserves
- continuing development of our high-quality, low-cost, oil sands projects
- advancing regulatory approvals
- advancing emerging oil sands projects

PROJECT APPROVALS
400 TO **500**
THOUSAND BBLS/D†
BY 2015

TRACK RECORD OF PERFORMANCE

14 YEARS OIL SANDS OPERATING HISTORY

Track record of being a low-cost operator who delivers strong financial results. We have best-in-class capital efficiencies, low SORs*** and a manufacturing approach to our business.

TECHNOLOGY INNOVATION

SOR is the amount of steam needed to produce a barrel of oil, a key measure of efficiency for operations using SAGD technology. A low SOR means you're more energy efficient, have lower costs and have a smaller environmental impact.

We continue to be committed to improving our recovery rates and reducing our impact on the environment.

FINANCIAL STRENGTH

INTERNALLY FUNDED GROWTH THROUGH STRONG CASH FLOW AND BALANCE SHEET

Our investment grade credit ratings reflect our quality assets, solid capital structure, financial flexibility and significant liquidity.

Our established base of conventional oil and natural gas assets generates operating cash flow to fund our oil sands growth.

Our hedging program manages commodity price exposure and locks in cash flow.

*BIIP: bitumen initially-in-place; see Additional Advisory on page 132
**NGLs: natural gas liquids
***SOR: steam to oil ratio
† Net to Cenovus

Delivering on our business plan: We have set specific milestones to measure our achievements as we grow our business and build NAV.

2010

ACHIEVED MILESTONES

- Shaped our teams, systems and culture; developed our policies and practices; and set the strategic direction for our company
- Announced plan to increase oil sands production to 300,000 bbls/d net by end of 2019
- Assessed oil sands resources, disclosed bitumen initially-in-place and provided more details about how we will grow our oil sands projects
- Grew reserves and contingent resources
- Submitted regulatory application for Narrows Lake (one of our emerging oil sands projects)
- Received regulatory approval and initiated sanctioning process for Foster Creek phases F, G & H
- Received regulatory approval for Grand Rapids SAGD pilot project and began first steam
- Restructured our internal organization to better align with our business plan
- Delivered excellent operating and financial results
- Divested non-core assets
- Established long-term agreement with Conklin community

2011F

MILESTONES SET SO FAR

- Grow reserves and contingent resources
- Execute stratigraphic well program (drill 450 wells) and assess results
- Advance environment key performance indicators and long-term impact forecasting
- Sanction Foster Creek phases F, G & H
- Achieve first production at Christina Lake phase C
- Anticipate receipt of regulatory approval for Christina Lake phases E, F & G and commence sanctioning process for E
- Expand the polymer flood and drill additional infill wells at Pelican Lake, which is expected to result in higher production
- Submit Grand Rapids regulatory application for a commercial operation
- Start up coker as part of Wood River CORE project
- Implement the Cenovus Operations Management System (COMS)
- Implement at least one new commercial technology from Cenovus's R&D program
- Integrate the six commitment areas of our Corporate Responsibility Policy into the company's business strategy in order to create value for both our business and the communities where we live and work

2012F

MILESTONES SET SO FAR

- Grow reserves and contingent resources
- Initiate sanctioning process for Narrows Lake phases A, B & C
- Drill 400 to 500 stratigraphic wells and assess results
- Implement at least one new commercial technology from Cenovus's R&D program
- Start gas cap air injection for thermal oil recovery pilot at Clearwater
- Increase production from Pelican Lake Wabiskaw

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The Cenovus Executive Team members bring expertise and energy to their roles. Collectively, they inspire our teams and steer the success of our business.

BROAD KNOWLEDGE + COLLABORATIVE APPROACH = **STRONG LEADERSHIP**

(Pictured left to right)

IVOR M. RUSTE
Executive Vice-President & Chief Financial Officer

JUDY A. FAIRBURN
Executive Vice-President, Environment & Strategic Planning

KERRY D. DYTE
Executive Vice-President, General Counsel & Corporate Secretary

HARBIR S. CHHINA
Executive Vice-President, Oil Sands

JOHN K. BRANNAN
Executive Vice-President & Chief Operating Officer

BRIAN C. FERGUSON
President & Chief Executive Officer

HAYWARD J. WALLS
Executive Vice-President, Organization & Workplace Development

SHEILA M. MCINTOSH
Executive Vice-President, Communications & Stakeholder Relations

DON T. SWYSTUN
Executive Vice-President, Refining, Marketing, Transportation & Development

"Everything we do is about increasing the value of the company. Our goal is to double our net asset value by 2015."

BRIAN FERGUSON

"We're building a vibrant and healthy organization that differentiates Cenovus."

HAYWARD WALLS

"We have the financial strength and flexibility to enable our ambitious plans."

IVOR RUSTE

"Innovation unlocked the oil sands. That kind of ingenuity will tackle the environmental challenges."

JUDY FAIRBURN

"We strive to be industry leading in our operations – from our approach to our results."

JOHN BRANNAN

"Engaging with our various stakeholders and telling the Cenovus story is critical to our success. We have a great story to tell."

SHEILA MCINTOSH

"Our commitment to safety, new ideas and improved technologies is strong. The status quo is unacceptable at Cenovus."

HARBIR CHHINA

"Our approach to governance provides a strong framework for achieving our plans."

KERRY DYTE

"Our downstream integration gives us less volatility and balances our commodity exposure."

DON SWYSTUN

"You can count on Cenovus's commitment to develop our resources safely and responsibly, and to always strive to be better at how we do it."

CLEAR VISION + SMART EXECUTION = **AN EXCITING FUTURE**

BRIAN C. FERGUSON
PRESIDENT & CHIEF EXECUTIVE OFFICER

With our first full year as an independent oil company behind us, I am proud of what we have accomplished at Cenovus in such a short time. It gives me great pleasure to report our accomplishments to you in this, our first annual report to shareholders.

2010 was a year of strong operational results, exceptional reserves growth and solid financial performance. One where we shaped our teams, our systems and our culture. Most importantly, it was one where we positioned Cenovus for future success by setting the strategic direction for our company. We did this by assessing our vast resource to better understand our growth opportunities, developing a 10-year business plan, and focusing on increasing production from our high-quality oil sands assets.

As part of our 10-year plan, we have set clear milestones to measure our success, which are outlined on page 18. The nature of oil sands means we are in a long-term business – so it's important that you know our milestones and can track our progress.

I am pleased to report that we met or exceeded all the key milestones we set for 2010.

In everything we do, our aim is to increase value for you, our shareholders. We are targeting to double our net asset value by 2015, and boost our oil sands production five-fold to 300,000 barrels per day net to Cenovus by the end of 2019. We also expect to provide you with a strong and sustainable dividend.

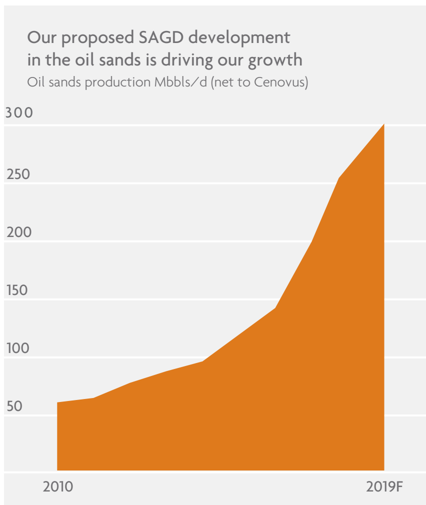
2010 – SETTING THE STAGE FOR FUTURE VALUE CREATION

Early in 2010, we undertook a third-party assessment to fully understand our oil sands resource. The evaluation, using some of the most rigorous standards in the industry, identified best estimate total bitumen initially-in-place on Cenovus lands of 137 billion barrels, of which 56 billion barrels are considered discovered.

We created our long-term plan to take advantage of these tremendous assets by focusing on bringing this high-quality resource into production.

By the end of 2010, our efforts throughout the year resulted in an independent evaluation determining that our proved bitumen reserves had increased by 33 percent over 2009 to nearly 1.2 billion barrels.

A particular highlight was that our Foster Creek and Christina Lake facilities increased production by 33 percent in 2010 compared with 2009, for a combined production of over 59,000 barrels per day net to Cenovus. At the same time, our operating costs at these facilities decreased 10 percent in 2010 compared to 2009, to an average



of $11.28 per barrel – all while we were operating with even more emphasis on working safely. To the credit of our entire operations team, their focus on safety resulted in fewer total incidents during the year.

We furthered our expansions at both Foster Creek and Christina Lake in 2010 and advanced development plans at two of our emerging projects, Narrows Lake and Grand Rapids. As well, our established oil and natural gas properties in Alberta and Saskatchewan continued to demonstrate strong cash-generating abilities, providing approximately $1.3 billion of operating cash flow in excess of their capital expenditures in 2010. The cash generated from our conventional oil and natural gas properties funds our continued oil sands growth, and the natural gas also fuels our oil sands and refining operations.

In our refining operations, we continued to concentrate on increasing capacity through a coker and refinery expansion (CORE) project at our Wood River Refinery in Illinois. Upon anticipated start up of the coker in the fourth quarter of 2011, we expect improved profitability from this part of our business.

Managing our business with a continued focus on value creation and cost control resulted in Cenovus having an even stronger financial position at the end of 2010 than at the start of the year. We have a healthy balance sheet, closing 2010 with a debt to capitalization ratio of 26 percent and debt to adjusted EBITDA ratio of 1.2 times. Total cash flow was strong at $3.21 per share for the year, while our capital investment in 2010 was $2.1 billion. At Cenovus, we take a responsible and careful approach to our financial strategy. We are committed to continuing to provide our shareholders with regular dividend payments as part of this disciplined approach.

You can read more about our accomplishments in the *2010 Year in review* section on pages 25 to 28 of this report.

Another significant action we undertook in 2010 was to organize ourselves internally to maximize efficiencies and better align our structure with our plan. We accomplished this by eliminating our operating divisions and creating a centralized operations team under the leadership of John Brannan, who assumed the new position of Executive Vice-President & Chief Operating Officer. John brings more than 30 years of oil and natural gas experience to this new role, and his leadership will drive continued achievements in our operations.

"2010 was a year of strong operational results, exceptional reserves growth and solid financial performance. One where we shaped our teams, our systems and our culture. Most importantly... we positioned Cenovus for future success by setting the strategic direction for our company."

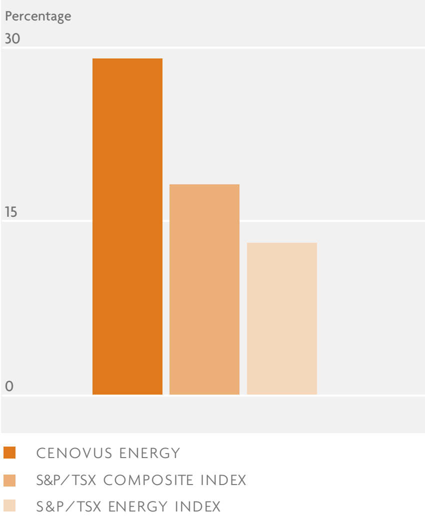
2011 – BUILDING ON OUR 2010 MOMENTUM

With the foundation of our company in place, 2011 will be focused on building on the momentum we achieved in 2010, by pursuing regulatory approvals, advancing construction of the expansion phases at Foster Creek and Christina Lake, and pursuing opportunities for production growth in the Greater Pelican Region.

The milestones we have set for 2011 align with our 10-year business plan and our goal of growing net asset value. They include executing our largest-ever stratigraphic well program to evaluate our undeveloped land, expand our contingent resource and advance projects into the regulatory queue.

As well, we are focused on delivering on our upstream operational targets and keeping our projects on schedule and on budget, so we can continue to crystallize the value our great assets provide for our company and our shareholders.

Cenovus shares outperformed the market in 2010
Total shareholder return (TSX)



THE VALUE OF A CENOVUS HOLDING WAS UP 29 PERCENT ON THE BASIS OF ALL DIVIDEND PAYMENTS BEING REINVESTED COMPARED WITH AN 18 PERCENT INCREASE IN THE S&P/TSX COMPOSITE INDEX AND 13 PERCENT FOR THE S&P/TSX ENERGY INDEX.

THE CENOVUS EQUATION – OUR KEY STRENGTHS

What sets Cenovus apart is the combination of our great financial and operating assets, our commitment to responsible operations, our ability to advance technology to improve our results, and the 3,500 dedicated people who make it all happen. People who bring decades of experience, knowledge and enthusiasm to their work. Thanks to them, we are able to develop new ideas, new technologies and better approaches.

I am proud of our achievements in bringing Cenovus to this point, and would like to acknowledge and thank our Board of Directors, our Executive Team, and our employees and contractors for demonstrating such dedication to Cenovus's success. We have an air of excitement, a can-do attitude and a driving passion to make Cenovus the best it can be. In a year of change, we maintained focus on building our company, we delivered on our targets, and we had excellent operating and financial results.

We are building a company that, at its core, believes in doing right by the environment and the communities where we live and work. We are focused on doing the right things to help provide the energy resources the world needs and relies on every day.

With demand for energy growing, you can count on Cenovus's commitment to develop our resources safely and responsibly, and to always strive to be better at how we do it. It's at the heart of the Cenovus equation. And it's our promise to you.

We have set ambitious goals for ourselves, but I believe we are in a strong position to realize our tremendous future. Our Executive Team and I look forward to the exciting possibilities that lie ahead.

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"As a unified operations team we will be better positioned to continue our focus on maintaining our operating momentum, delivering on our business plan and being a safe, responsible operator."

GREAT TRACK RECORD + FRESH THINKING = **OPERATIONAL EXCELLENCE**

JOHN K. BRANNAN
EXECUTIVE VICE-PRESIDENT
& CHIEF OPERATING OFFICER

Late in 2010 you were named Cenovus's Chief Operating Officer. How does this new role change Cenovus's approach to operations?

Let me start by saying I'm really pleased to be working closely with all the areas of our operations – our oil sands, conventional oil and natural gas teams, as well as our refining and marketing teams. Everyone has been doing great work. Having one operating team rather than separate operating divisions allows us to optimize the way we work and take advantage of knowledge sharing and technology improvements across our business. Additionally, the unified operating team is supported by a central organization for regulatory, drilling, procurement, continuous improvement, land functions, process improvement, and health and safety. Most importantly, as a unified operations team we will be better positioned to continue our focus on maintaining our operating momentum, delivering on our business plan and being a safe, responsible operator.

Cenovus believes it's important to be a low-cost operator. How do you achieve that?

We're recognized in the industry as being a low-cost operator with leading capital efficiencies and we're proud of our track record. Our low costs are the result of a number of factors. While it's true that our low steam to oil ratios and high-quality reservoirs allow us to keep costs down, it's also due to the manufacturing approach we take in the design, construction and operation of our facilities. Our teams build our projects in manageable phases using repeatable designs. We design the process flow diagrams, equipment, and operating processes to be similar at all our SAGD facilities. Our teams then apply their experience and learnings to each new phase and implement advancements in technology once they've become proven – all with the goal of improving efficiency and reducing costs, without sacrificing our commitment to high-quality facilities, safe operations and minimal environmental impact.

How do you manage cost inflation in your business?

We have a philosophy at Cenovus that holds everyone accountable for spending our money wisely regardless of the economic environment. So having that kind of overall attentiveness gives us an advantage when dealing with inflation. One way we manage inflation is through our approach to development. For example, by using in-house construction management teams, we take control of our costs and reduce potential for overruns by having Cenovus staff accountable for capital spending.

Another way we manage inflation is through our module fabrication yard in Nisku, Alberta, located just outside of Edmonton. Having an established module yard allows us to control costs and maintain schedules and greatly reduces the amount of rework needed in the field. As an example, out of the 145 modules required for the Christina Lake phase C expansion, only two modules required minor modifications during installation – obviously a significant cost and time savings and a substantial increase in the efficiency of our construction teams.

The location of our projects also helps us control inflation. We're fortunate to be located near Bonnyville, Cold Lake and Lac La Biche, which experienced lower inflation than areas such as Fort McMurray during the last upswing in oil sands activity.

Lastly, where we can, we train and hire locally and use businesses and services in the areas around our operations. It's important to us that we work with local communities and stakeholders to establish a win-win scenario for all.

Cenovus talks a lot about steam to oil ratio. What is it and why is it such an important measure?

Steam to oil ratio, or SOR, is the amount of steam required to produce one barrel of oil. It's a reflection of the quality of the reservoir and the approach used to develop the resource. It's also the single most important factor that influences the economics of a SAGD project, the lower the SOR, the better. Approximately 60 to 70 percent of a SAGD plant's function is dedicated to water handling for steam production. We currently have some of the lowest reported SORs in the industry. In 2010, our demonstrated SORs at Foster Creek and Christina Lake were about 2.2 combined. A low SOR means we need less steam to produce oil so, on a per barrel basis, it means better capital efficiency indicated by our lower capital costs.

Our most significant operating cost stems from burning natural gas to turn water into steam. Our low SOR keeps our operating costs at a minimum. It also leads to other benefits such as a smaller surface footprint, lower emissions and reduced water use, which help us meet our environmental objectives as well as our financial objectives.

I'm extremely proud of the work we've done to successfully lower our SOR.

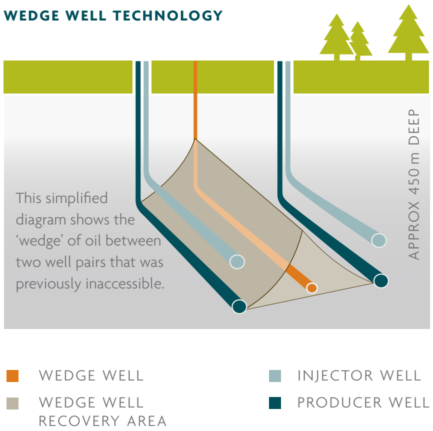
Cenovus has made a commitment to implement at least one new commercial technology per year. Why is research and development so critical to the company's success?

Research and development is a huge focus for Cenovus. Historically, we've been able to implement at least one new technology in our operations each year and believe we can continue that trend.

Take the development of SAGD for example. We believe that this technology, which has only been commercially applied for about a decade, still has opportunities for improvement with respect to developing and optimizing our recovery schemes. We plan to continue to lead the industry in implementing new approaches to how we're able to extract the oil out of the ground. Our recent use of wedge wells is a great example of that. It's a Cenovus technology that's already changing the way we develop our assets, and we haven't even begun to fully utilize it in our operations. At year end 2010, about 13 percent of Foster Creek's total production came from wedge wells, which cost only about half the amount required to drill a SAGD well pair. At the end of 2010 we had drilled 51 wedge wells at Foster Creek with 33 producing, and had one producing wedge well at Christina Lake. Building on this success, we're planning to drill 10 more wedge wells at Foster Creek in 2011.

We believe research and development is critical to the longevity of our business, which is why our ability to advance technology is an important part of who we are as a company. It's how we've increased efficiency, recovery and project returns. It's also reduced our costs and our overall environmental intensity. And it's how we're going to continue to improve our operations in the future.

WEDGE WELL TECHNOLOGY



WEDGE WELLS ARE SINGLE HORIZONTAL WELLS DRILLED BETWEEN TWO SAGD WELL PAIRS TO CAPTURE PREVIOUSLY INACCESSIBLE OIL IN THE RESERVOIR. THEY REQUIRE LITTLE OR NO STEAM TO EXTRACT THE REMAINING OIL, MAKING IT POSSIBLE TO INCREASE OIL RECOVERY WHILE REDUCING OPERATING COSTS, WATER USE AND ENERGY USE PER BARREL.

If oil sands are your growth driver, what role do your other resources play?

We have a great balance of growth and financial assets. We think of our conventional oil and natural gas properties as financial assets. They are low-cost, high-return assets that, with modest capital investment, will generate substantial operating cash flow and will experience a fairly shallow decline. Our natural gas business also acts as an economic hedge against price fluctuations, because natural gas fuels our oil sands and refining operations. Our oil operations include Weyburn and other properties in southern Alberta and Saskatchewan while our natural gas properties are in Alberta. On the growth front, in addition to the growth from our oil sands, we expect to double heavy oil production at Pelican Lake as a result of our multi-year infill drilling program.

When will the Coker and Refinery Expansion (CORE) project at Wood River be complete?

The CORE project is a large-scale expansion that started in September 2008 at our Wood River Refinery in Illinois, which is designed to process 306,000 barrels per day of crude oil. Construction is expected to be substantially complete in the third quarter of 2011, with start up of the coker expected in the fourth quarter. Once complete, Wood River will join our Borger Refinery in Texas as one of the more complex refineries in the United States. The increased complexity is a result of adding a new coker, associated processing units and other upgrades to the existing refinery. Together, they will provide the refinery with the flexibility to take advantage of lower cost feedstocks and improve overall refining capacity and yields. The refinery modifications will increase Wood River's crude capacity by 50,000 barrels per day and heavy crude oil capacity will more than double to 240,000 barrels per day. These downstream assets protect us against wide light/heavy differentials and enable us to extract value across the entire chain from bitumen all the way to transportation fuels.

Safety is a core value at Cenovus. How do you ensure that value translates into action and results in a good safety record?

The health and safety of our workforce is of paramount importance at Cenovus. But it's not just about saying it. It's about living it every day. We have eight safety commitments that guide how we conduct our business. All eight are critical to reinforcing the behaviour and attitude we want to see in our staff, but the first one best illustrates our commitment to safety. It states, 'Our work is never so urgent or important that we cannot take the time to do it safely.'

While these commitments are the foundation of our goal to have an injury-free workplace, they are put into practice through awareness, education and empowerment of our employees and contractors. Most gratifying of all is that our increased focus on safety has resulted in a significant reduction of on-the-job injuries over the past three years. And that's what's really important. Because working at Cenovus really does mean working safely.

In our first full year as an independent company, we achieved a number of milestones and delivered on our commitment to develop energy resources safely and responsibly. We met production targets while maintaining safe, disciplined operations. We accelerated expansions at our core oil sands operations, Foster Creek and Christina Lake. Cenovus is well positioned for future success.

KEY MILESTONES ACHIEVED + STRONG RESULTS = **A YEAR TO BE PROUD OF**

STRONG 2010 RESULTS

Enterprise value: $28.5 billion[1]

Shares outstanding: 752.7 million[1]

Oil & NGLs production: 129 Mbbls/d

Natural gas production: 737 MMcf/d

Proved & probable reserves: 2.4 billion BOE[1]

Total acreage: 7.2 million net acres[1]

Bitumen acreage: 1.4 million net acres[1][2]

Refining capacity: 226 Mbbls/d

All numbers shown are net to Cenovus on a before royalties basis.

(1) As at December 31, 2010.

(2) Includes exclusive rights to lease 0.6 million net acres on our behalf and/or our assignee's behalf.

DEVELOPED OUR 10-YEAR BUSINESS PLAN

Approved June 2010 by our Board of Directors. See the *Strategy snapshot* on page 16.

CHANGED OUR ORGANIZATIONAL STRUCTURE

We replaced our operating divisions with a centralized operations team. It took effect December 1, 2010.

CONFIRMED OUR VAST OIL SANDS POTENTIAL

An independent evaluation was completed in the spring of 2010 that confirmed 5.4 billion barrels of best estimate bitumen economic contingent resources on Cenovus's lands. A subsequent independent evaluation was completed at the end of 2010 that confirmed 6.1 billion barrels of best estimate bitumen economic contingent resources – an increase of 13 percent. The information from these independent evaluations is supported by a great deal of data, including thousands of kilometres of seismic data and a high number of well penetrations.

Our proved bitumen reserves, also based on independent evaluations, grew from 866 million barrels at year-end 2009 to 1,154 million barrels at year-end 2010, an increase of 33 percent.

TOTAL 2010 DIVIDEND:

80¢

PER COMMON SHARE

These numbers – both proved reserves and contingent resources – reflect the high quality of our assets and the great work being done by our teams. For the company as a whole, the increase in our reserves, combined with highly competitive proved finding and development costs* for 2010 of $3.65 per barrel of oil equivalent confirms the wealth of opportunity we have on our lands.

COMMITTED TO TECHNOLOGY DEVELOPMENT

As part of our business plan, we have committed to implement at least one new commercial innovation each year. We have more than 50 research and development projects underway at any given time – about three-quarters of which should result in environmental improvements.

PROGRESSED OUR ENVIRONMENTAL OPPORTUNITY FUND

We committed to invest in three new opportunities in 2010, bringing the number of current environmental investments to seven. The fund invests in companies and external research groups developing emerging or early-stage technologies that focus on water treatment and management, energy efficiency, alternative energy, emissions reduction, environmental remediation and land disturbance mitigation. Information about how to apply is on our website.

*Without changes in future development costs. See our Additional Advisory on page 132.

REACHED ROYALTY PAYOUT AT FOSTER CREEK

In February 2010, our Foster Creek project became Alberta's largest producing SAGD project to reach payout for royalty purposes, which means higher royalties are now paid to the government. This milestone reflects Foster Creek's strong financial and operational performance. Foster Creek started as a pilot project in 1996 and, in 2001, became the first commercial SAGD project in the industry.

ACCELERATED EXPANSIONS AT OUR MAJOR SAGD OIL SANDS PROJECTS

Foster Creek In September 2010, we received regulatory approval to build three new expansion phases (F, G & H) at Foster Creek. Current gross production capacity at Foster Creek is 120,000 barrels per day, and each one of the three phases is expected to add 30,000 gross barrels per day, bringing total production capacity up to 210,000 gross barrels per day. Work on phase F is underway.

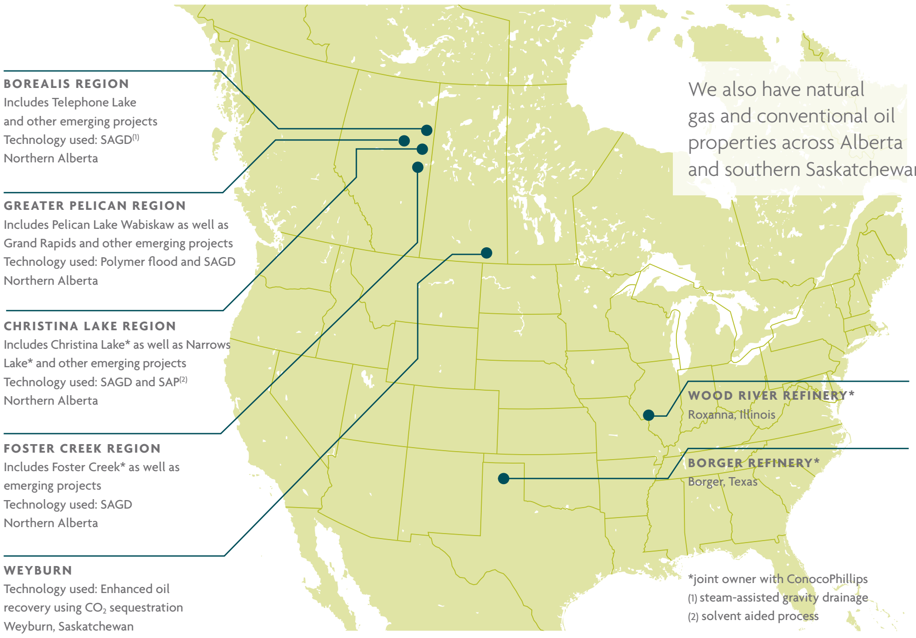
Christina Lake We're advancing expansion phases C and D at Christina Lake, which received regulatory approval in 2008. We continued construction of phase C in 2010 and began constructing phase D. Phase C will add about 40,000 barrels per day of gross production capacity with first production expected in Q3 of 2011. Phase D will also add about 40,000 gross barrels per day of production capacity with first production expected in 2013. We expect to bring these phases on stream at an industry-leading capital efficiency of about $22,000 per flowing barrel. These two expansions will bring the production capacity to 98,000 barrels per day on a gross basis from its current 18,000 barrels per day. We're currently awaiting regulatory approval for three more expansion phases (E, F & G), which would add an additional 120,000 barrels per day of gross production capacity.

BROUGHT TWO EMERGING OIL SANDS PROJECTS CLOSER TO DEVELOPMENT

Narrows Lake In June 2010, we applied for regulatory approval of a project at Narrows Lake, located northwest of our Christina Lake project. As part of that application, we have consulted with the communities located near the project to explain our plans. Narrows Lake will be developed in phases up to a gross production capacity of about 130,000 barrels per day. The application is the first commercial project to include the option to use SAP, a solvent aided process that increases oil recovery.

Grand Rapids We're taking steps to develop a future oil sands project in the Greater Pelican Region, about 300 kilometres north of Edmonton. In December 2010, we received regulatory approval for a SAGD pilot in the Grand Rapids formation. Drilling of the SAGD well pair is complete, and in late 2010 we began injecting steam into the formation. If the pilot is successful, we plan to file a regulatory application for a 180,000 barrels-per-day commercial operation.

OIL IS OUR GROWTH DRIVER



"We're excited about the way we're able to transfer knowledge from one area to another. We're applying horizontal drilling and completion techniques from our Saskatchewan, Lower Shaunavon and Bakken developments to our Drumheller, Brooks North and Langevin oil development programs."

KEVIN KELLY
TEAM LEAD, DRUMHELLER/BOYER

DEVELOPED MULTI-YEAR GROWTH PLAN FOR PELICAN LAKE WABISKAW

We have plans for significant growth of our existing Pelican Lake Wabiskaw production as we expand our polymer enhanced oil recovery project. Our multi-year growth plan involves more than doubling existing production to 40,000 to 50,000 barrels per day.

MAINTAINED A STRONG FINANCIAL POSITION

Both our debt to capitalization ratio of 26 percent and debt to adjusted EBITDA ratio of 1.2 times were at or below the low end of our target ranges. Our cash flow was strong in 2010 at $2.4 billion and aligned with our expectations. The majority of the cash required to fund our oil sands growth is generated by our conventional oil and gas properties. In 2010, these properties contributed about $1.3 billion of operating cash flow in excess of the capital spent on them.

EXPLORED SHAUNAVON AND BAKKEN FOR NEW OPPORTUNITIES

Our Lower Shaunavon and Bakken medium and light oil assets in Saskatchewan are early stage development opportunities for Cenovus. We had 25 wells producing at year-end 2010 with plans to drill an additional 36 horizontal wells in the area in 2011. We anticipate production at the end of 2011 could reach 5,700 barrels per day.

OPTIMIZED COAL BED METHANE (CBM) PRODUCTION FROM ESTABLISHED SHALLOW GAS OPERATIONS

In 2010, we undertook a 900 well recompletion program in our shallow gas operation to further assess CBM potential on our lands. Total CBM production from our Brooks and Langevin properties was approximately 30 MMcf/d from about 1,400 recompleted shallow gas wells. The long-range plan calls for over 6,500 CBM recompletions in existing shallow gas wellbores.

GREW OIL SANDS PRODUCTION BY
33%
OVER 2009

"We're a company that follows through on our commitments."

ADRIAN MITCHELL
RESERVOIR ANALYST

OPERATOR ADJUSTING VALVES AT THE WEYBURN FACILITY

CELEBRATED TENTH ANNIVERSARY OF OUR WEYBURN CO_2 PROJECT

In September 2010, we celebrated the tenth anniversary of our Weyburn carbon dioxide (CO_2) enhanced oil recovery project, which uses technology to improve both oil recovery and our environmental performance. Since CO_2 was first injected into the reservoir in 2000, more than 16 million tonnes of CO_2 have been stored at Weyburn, which otherwise would have been vented into the atmosphere. The Weyburn oil field is located in southern Saskatchewan.

TOLD OUR STORY

Presenting to investors and government officials, doing media interviews, meeting with community leaders, groups and landowners, working with Aboriginal communities, and communicating with our employees – we remain committed to telling our story to all our stakeholders to help them understand our company, the quality of our asset base, the strength and expertise of our teams, our solid financial position and our commitment to operating safely and responsibly.

DIVESTED NON-CORE ASSETS

In 2010, we sold some non-core assets in southeastern Alberta and southwestern Saskatchewan for net proceeds of $156 million. Our total divestitures for the year were $307 million. As part of maximizing shareholder value, we continually look to improve our asset base and sell non-core assets as long as market conditions are favourable. We believe it's good business practice to sell assets that aren't part of our core business and use those funds to invest in assets that are in our area of focus.

OUR COMMITMENTS:
RIGOROUS
RESPECTFUL
READY

"I'm really proud of the focus we have on developing technologies that will reduce the impact our operations have on the environment even further."

SUBODH GUPTA
TECHNOLOGY ENHANCEMENT ADVISOR

WEDGE WELLS AT FOSTER CREEK

AS PART OF TELLING OUR STORY, WE CREATED ADS IN THE FALL OF 2010, FOCUSED ON THE VALUE OIL AND NATURAL GAS BRING TO OUR LIVES. A SECOND SET OF ADS, WHICH LAUNCHED IN EARLY 2011, ILLUSTRATE WHAT A SAGD OPERATION LOOKS LIKE. THE ADS CAN BE VIEWED ON OUR WEBSITE.

CENOVUS VICE-PRESIDENTS JOIN THE CONKLIN RESOURCE DEVELOPMENT ADVISORY COMMITTEE TO SIGN A LONG-TERM AGREEMENT WITH THE COMMUNITY OF CONKLIN.

ESTABLISHED LONG-TERM AGREEMENT WITH CONKLIN COMMUNITY

We signed a long-term agreement with the Aboriginal community of Conklin, which is located less than 20 kilometres from our Christina Lake project in northern Alberta. The agreement will provide mutual benefits for as many as 40 years and outlines our commitment to working and engaging with the Conklin community on the following matters:

- providing benefits such as employment, community investment, business development, education and training
- determining how we'll engage with the community as our projects grow and how we'll work together to address any issues that arise
- protecting the environment and protecting Christina Lake
- providing financial and other resources that will help Conklin residents adapt to change in their area

ADVANCED CORPORATE RESPONSIBILITY AT CENOVUS: NEW POLICY, NEW MEASURES

At Cenovus, corporate responsibility (CR) is integrated into the way we do business. In 2010, we created a policy that reflects our company and our commitment to CR. It sets out our guiding principles relating to leadership, corporate governance and business practices, people, environmental performance, stakeholder and Aboriginal engagement, and community involvement and investment. Additionally, in July 2010, we released our first set of CR performance measures. These measures set a firm foundation for future public reporting on our company's non-financial performance. In developing these measures we used the Global Reporting Initiative guidelines as a framework for reporting and have begun to align our performance metrics with the standards set out by the Canadian Association of Petroleum Producers' *Responsible Canadian Energy* program.

MADE A DIFFERENCE IN THE COMMUNITIES WHERE WE LIVE AND WORK

Company giving In 2010 Cenovus worked with 427 organizations, providing both monetary and in-kind assistance in the communities where we live and work. We also became an Imagine Canada Caring company, which means we give one percent of our pre-tax profits to charitable or non-profit organizations. In 2010 that resulted in $13.5 million in donations.

Employee giving Our employees contributed more than $3.2 million (including the company match) through our annual giving campaign, matching gifts and volunteer programs. The money benefited nearly 700 charitable organizations across Canada. During the annual campaign, which runs every October, employees designate their donation amount to charities of choice, with Cenovus matching donations dollar for dollar.

AT CENOVUS WE BELIEVE IN BEING A PART OF THE COMMUNITIES WHERE WE LIVE AND WORK. IT'S ABOUT BEING INVOLVED AND MAKING A POSITIVE DIFFERENCE INCLUDING COMING TOGETHER IN THE SPIRIT OF GIVING TO DONATE GIFTS FOR CHILDREN AND TEENS DURING THE HOLIDAYS.

"It was great to have the Executive Team visit us in the field."

ART LAURIN
PRODUCTION COORDINATOR

THE EXECUTIVE TEAM VISITS OUR PELICAN LAKE SITE

CENOVUS NAMED TO DOW JONES SUSTAINABILITY INDEX (DJSI) AND CARBON DISCLOSURE LEADERSHIP INDEX

The DJSI North America Index recognizes companies from Canada and the United States for their sustainability performance. Companies are selected based on an annual assessment of economic, social, environmental and corporate governance performance. The Carbon Disclosure Leadership Index recognizes companies for their leadership in the reporting of greenhouse gas emissions.

TOTAL RECORDABLE INJURY FREQUENCY LOWERED BY

15%

The people of this company embody the spirit of Cenovus. **Rigorous** in their commitment to smart resource development. **Respectful** in their commitment to doing right by the environment and communities where Cenovus operates. **Ready** in their commitment to embracing fresh thinking and new ideas.

KNOWLEDGE + DEDICATION = **THE RIGHT PEOPLE**

"Cenovus is an excellent place to work. I get the opportunity to work with great people on innovative projects."

NATHAN HYLTON

"It's really great to work at a company that values innovation and embraces new ideas as part of our everyday approach to doing business."

NASSER AWADA

"I come to work every day knowing that people rely on us for the oil and natural gas we produce."

CHRIS OLIVER

"It's exciting to be part of a company with both an established history and track record and yet a totally new identity, new culture, new way of doing things."

TREVOR BORS

"It's been a rewarding experience introducing our local stakeholders to our company and our plans."

CAM KOPANSKY

"Helping to build a new company has been an exciting experience."

JASON SWITZER

"I don't know what the next year will bring but here's hoping that year two will be as positive and successful."

KIM YEE

"It's important to me to work for a company that takes safety so seriously."

COLE BROST

"There's such a strong spirit of camaraderie at Cenovus."

LIZ YOUNG

Trevor Aadland / Ali Abbassi / Jason Abbate / Yasmin Abdul / Phillip Abraham / Phil Abrey / Nicole Abs / Michalene Adair / Aaron Adam / Jennifer Adams / Stewart Adams / Jamie Agnew / Annie Agustin / Rhonda Aiello / Abayomi Akande / Jennifer Alaric / Sheila Albon / Gary Alden / Everett Alderdice / Neil Aldridge / Jim Aleman / Michael Alessio / Renee Alessio / Andell Alexander / Faisal Alimohd / Travis Alkier / Courtney Allan / Denise Allan / Michael Allan / Dale Allen / Roberto Allende-Garcia / Douglas Allin / Cindy Alpaugh / Brett Altwasser / Vernon Alvis / Jason Aman / Jon Amerl / Kim Amirault / Giuseppe Ammirati / Arthur Amyotte / Ligen An / Andrea Anderson / Brent Anderson / David Anderson / Gary Anderson / Judy Anderson / Michael Anderson / Richard Anderson / Timothy Anderson / Todd Anderson / Ken Andres / Edith Andrew / Mark Andrews / Tamer Antar / Gwenda Anweiler / Kimberly Appleby / John Arcovio / Lesley Arnett / Caroline Arnieri / Royce Arnott / Aaron Arsenault / Julian Arsenault / Joel Arthurs / Michael Arychuk / Abbas Arzpeyma-Nemati / Shane Ashby / Marijane Ashforth / Derrick Ashworth / Andrew Asplund / Karen Asselstine / Theodore Assie / Laverne Atkinson / Tony Atwood / Lawrence Auger / Lenny Auger / David Austin / Mark Austin / Nasser Awada / Brett Aylwin / Karmyn Ayn / Cole Babey / Wade Bachur / Erica Back / Tracy Bader / Mohammad Bagheri / Mohammad Bahadori / Robert Baillargeon / Brian Bain / Arnold Baker / David Baker / Evan Baker / Nadia Baker / Rawleen Baker / Robert Baker / William Baker / Colin Ball / Dale Ball / Susan Ballendine / Christopher Ballesteros / Wayne Bamber / Peter Bandola / Chad Barber / Brenda Bardell-Resch / Jason Bardick / Ryan Bardick / Paul Barker / Sandra Barker / Debra Barnett / Arnold Baron / Robert Baron / Courtney Barr / Marc Barrette / Dallas Barrie / Stuart Barrie / Shirley Barron / Bradley Barrow / Darcy Barry / Jamie Barsness / Connie Barteaux / Lori Barth / Michele Barth / Ronald Bartlett / Isabella Baslios / Barbara Bateman / Keith Bateman / Wayne Bateman / Darwin Bateyko / Kelly Bauman / Kelvin Bauman / Vincent Bax / Susan Bayly / Elizabeth Bayrak / Richard Beale / Leslie Beard / Dale Beaton / Aime Beaulac / Lori Beaulieu / Theran Beaulieu / Javier Becaria / Jessica Beck / Robert Beckett / Jeffrey Beckford / Jacqueline Beckie / Niel Beckie / Kenneth Beierbach / Jeremy Belair / Catherine Belanger / Dale Belbin / Lloyd Belcourt / Matthew Belitsky / Carrie Bell / Diane Bell / Kelly Bell / Scot Bell / Irene Belthazar / Marisol Ben / Corey Beniuk / Jason Beniuk / Jeffery Beniuk / David Benn / Greg Benzon / Corey Berg / Grant Bergos / Alan Berkiw / Maria Bermudez / Stephen Bernard / Mark Berrett / Tanya Berry / Leona Bertagnolli / Shawna Bertin / Julie Bertram / Mark Bertrand / Edward Bertschi / CherylLyn Best / Monica Betancourt / Tracy Bialowas / Ovidiu Bibic / Cody Biech / Alice Bienia / Dean Bierkos / Jo-Ann Biggs / Mark Bilozir / Mark Bilyk / Paul Binassi / Brandi Biollo / Chad Biollo / Lori Birdsell / Jillian Birnie / Bradley Bischoff / Amanda Bishop / Cassandra Bishop / Tyler Bishop / Tom Bissell / Darin Bitz / Christopher Blackwood / Ryan Blais / Trevor Blake / Deborah Bland / Connie Blatch / Adam Blazenko / Brenda Blazenko / Michael Bleackley / Blake Bloor / Brenda Bloski / Phil Blower / Glen Blythe / Leslie Boc / Scott Bodnar / Kerry Bohnet / Denis Boivin / Blaine Bolen / Kenneth Bolstad / Kevin Bolton / Glen Bonogofski / Kyle Boon / Rupam Bora / Bryan Boratynec / Albert Bordeleau / Gail Bordeniuk / Robert Borgen / Joseph Borras / Trevor Bors / Anna Bortolotto / Deborah Bosse / Moira Botham / Roger Boucher / Elisa Bourget / Crystal Bowen / James Bowman / Matthew Bowman / Michael Bown / Wayne Boylan / Rosana Bracho / Ian Braconnier / Darcy Bradley / Hugh Bradley / Leanne Bradley / Kim Brady / Sean Brady / John Brannan / Chad Branvold / Darlean Brasic / Gilles Brazeau / Jessica Brears / William Brears / Edmond Breland / Ryan Bremer / Michael Brennan / Lynda Briand / Carol Briceno / Stephen Brink / Claudine Brinston / Debora Brisson / Danielle Broadwell / Glenn Bromley / Pierre Brosseau / Cole Brost / Benjamin Brown / David Brown / Diane Brown / Gary Brown / Kevin Brown / Mary Brown / Terry Brown / Wade Brown / Jason Browne / Jamie Bruinsma / Jessica Bruneau / Edlyn Bruni / Donald Bryan / Nickole Bryan-Johnson / James Bryden / Daniel Bryson / Rodney Buchan / Christopher Buchanan / Brad Buckingham / Kent Buckingham / Dean Buckosky / Joseph Bueckert / Brent Bull / Stjepan Bulmer / Michael Bumstead / Candace Bundus / Tara Bunes / Jamie Bunka / Alfred Burk / Dean Burkart / Deborah Burke / Thanh Burns / Geoffrey Burrowes / Janet Burton / Cindy Busch / Randi Busenius / Heather Bush / Chad Buteau / Cayley Butt / David Butterwick / Brian Bylo / Jennifer Byrnes / Amanda Cabaj / Bernadette Cadden / Rex Cagas / Jerry Callaghan / Jenni Calvert / Cremilde Camara / Cambridge / Anna Cameron / Lauressa Cameron / Michael Cameron / Earl Campbell / James Campbell / Patrick Campbell / Ryan Campbell / Sandra Campbell / Christian Canas / Patricia Cancade / Carissa Caouette / Matt Cardall / Lance Cardinal / Donna Carey / Andrew Carleton / David Carley / Ercidio Carli / Linda Carr / John Carson / Nancy Carson / Paul Cary / Janne Cash / Teresa Cassetta / Miguel Castillo / Nory Cayago / Brian Celaire / Dan Cesario / Renee Chabeniuk / Daniel Chambers / Andy Chan / Betty Chan / Chong Chan / Edward Chan / Tammy Chan / Wai Chan / Steven Chang / Giselle Chao / Colin Chapman / Franklyn Charles / Dawn Chau-Lam / Brady Cheek / Qiaozhi Chen / Zhen Chen / Ryan Cherniwchan / Stacy Chessall / Daniel Cheung / Joseph Cheung / Winifred Chew-Semple / Michelle Cheyne / Harbir Chhina / Hicham Chibl / Katharine Chidley / Alberta Chikmoroff / Julie Chim / Leonie Chin / Tom Chin / Frank Chinski / Lisa Chinski / Beth Chisholm / Stephen Chiu / Robert Chorney / Lawrence Chou / Eva Chow / Roger Chow / Sherry Chow / Ruth Christensen / Brad Christian / Gordon Christian / Duane Christiansen / Bradley Christie / Sandy Chu / Kyle Chudyk / Linda Chueng / Darrell Church / Jeremy Church / Mark Churla / Manolito Cillo / Michael Clark / Kelley Clarke / Robert Clarkson / Mylene Clavette / Cameron Cline / Cindy Cloutier / Melissa Clow-Gordon / Brenda Coates / Adam Cocks / Donald Cocks / Michael Cody / Christopher Colantonio / Kevin Cole / MaryJane Cole / Eric Collins / Adam Colosimo / Taylor Comb / Peter Conacher / Brian Connolly / Cindy Connolly / Roger Connolly / Whitney Connolly / Joyce Conrad / Bradley Cook / Debbie Cook / Leighton Cook / Brandon Cooke / Kevin Cooke / Shane Cooke / Sherel Cooney / Cooper / David Cooper / Gordon Copp / John Coppock / Joshua Cornet / Daniel Corriveau / Gregory Cosma / Stephen Costello / Allain Cote / Leanne Courchesne / Darryl Courts / Alan Cox / Robert Cragg / Robert Cragg / Ann Craig / Laurie Craig / David Craigen / Mitchell Crane / Tyson Craney / Robert Craswell / Ann Crawford / Colbey Crawford / Warner Crawford / Kelly Creasy / Darcy Cretin / Roger Crocker / Daniel Cronin / Lloyd Crosby / Colleen Crowe / Doug Crowe / Susan Crowley / Lucas Crutchfield / Sharon Culley / Ian Cully / Mirjana Curcic / Darren Curran / Reginald Curren / Thomas Currie / Darrell Curtis / Will Cuthbert / Carl da Silva / Kyla DaCosta / Jana Dagsvik / Jeremy Daku / Lori Daley / Noemi Dani / Jacquelyn Daniels / Ryan Daniels / Darren D'Arcangelo / Christopher D'Arcy / Zachariah Darwiche / Amitava Datta / Victoria David / Adam Davidson / Derrick Davidson / Jefferey Davies / Laverne Davies / Monique Davies / Theodore Davies / Joan Davis / Marie Davis / Stephen Davis / De Blasio / Susie De Giusti / David Deacon / Christopher Deakin / Joseph DeBeaudrap / Ann DeBoer / Bradley Decker / Debra Dedora / Lindsey DeGusti / Leanne Deighton / Terry Dejikhangsar / Gerald Del Frari / James Delaney / Rhona DelFrari / Sheri Delf-Smithson / Justin Dell / Richard Dembicki / Greg Demchuk / Mark Demchuk / Myles Denis / Ian Denney / Kevin Depner / Dustin Derkach / Kelly Derlago / Michael Dery / Christine Deschamps / Darlene Desharnais / Jason Desilets / Melissa Desjarlais / Rachel DeSouza / Rachel Desroches / Henry Desy / Gene Dethlefsen / Tracy Devitt / Amandeep Dhillon / Annette Di Palma / Everett Diamond / Carolina Diaz-Goano / Cheryl Dick / Geoff Dickinson / Jennifer Dickinson / Garry Didow / Leland Dierkhising / Bradley Diesel / Duane Diesel / Ling Ding / Marsha Dixon-Robicheau / Derrick Dobrowski / Russell Dodd / Maria Dodsley / Wade Doering / Colleen Doering / Amanda Doggett / Patricia Doherty / Nicole Doig / Tamara Doige / Ross Dollin / Steve Donaldson / Gregory Donaldson / Heather Donauer / Dahai Dong / Debra Dorcas / Charlene Dorey / Brent Dorval / Rene Dorval / Chad Doucet / Lynne Douglas / Michael Douglas / Cibele Dourado / Patrycja Drainville / Brenda Draper / James Dribnenki / Kenneth Dryden / Lili Du / Marc Dubord / Marc Dubrule / Roger Ducharme / Marcel Duchesneau / Thomas Dueck / Katharina Duford / Olga Dumitrache / Dave Duncan / Dallas Dundas / Wesley Dundas / Marilyn Durant / Joseph Dusseault / Peter Duthie / Kelly Dutnall / Karanvir Dutt / Andrew Dutton / Kirk Duval / Clarence Dyck / Elaine Dyck / Erwin Dyck / Russell Dyck / Victor Dyck / Heather Dyer / Nicole Dykstra / Joyce Dyson / Kerry Dyte / Jeff Ealey / Leslie Eckert / Micah Eckert / Rodney Eckes / Bonnie Edmonds / Andrew Edmunds / Kathleen Edmunds / Robert Edwards / Lloyd Ehmann / Gabriele Ehnes-Lilly / Jennifer Eisenberg / Nolan Eisnor / James Ekelund / Mohamed Elashry / Tylor Ell / Christopher Elliott / Katherine Elliott / Michael Elliott / Norman Ellis / Timothy Ellis / Keith Ellwood / Shamel Elsayed / Lee Emms / Leslie Emms / Grace Eng / Michael Engler / Randy Engler / Ian Enright / Shawn Epp / Tamar Epstein / Toby Ergang / Devan Erickson / Blaine Erne / Rita Erven / Brent Espersen / Luigi Esposito / Phillip Esslinger / Timothy Etcheverry / Audrey Etherington / John Eubank / Donald Evans / Ryan Evanson / Stephen Ewart / Kelly Ewasiuk / Wade Ewen / Jason Ewing / Lawrence Fabbro / Steve Fader / Greg Fagnan / Wayne Fairbrother / Judy Fairburn / Bradley Falez / Ali Falsafi / James Fann / Ian Farrell / Jaclynn Farrow / Olugbenga Fasesan / Shadi Fattahi / Paul Faucher / William Faulkner / Stephanie Fawcett / Lynette Featherstone / Bonnie Fedoration / Thomas Fedoruk / James Fehr / Cindy Feldman / Shawn Fellner / Danielle Fendelet / Yongyi Feng / Ryan Ferdais / Colin Ference / Brian Ferguson / Kenneth Ferguson / Tanis Ferguson / Tracy Ferguson / Kevin Ferreira / Pierre Feser / Dario Ficaccio / Mark Fieger / Dorothy Filiatrault / Brett Filkohazy / Earl Finch / Scott Findlay / Kelly Finigan / Lorne Firkus / Colin Fischer / Gary Fiselier / Ernest Fisher / Ryan Fisher / Richard Fitzel / Cara Fitzgerald / Gail Flaherty / Grant Flaig / Kelly Flaig / Sherie Fleming / Beth Florio / Ellen Fong / Kelly Forbes / Kyle Forbes / Michael Forbes / Allan Ford / Devon Ford / Glenn Forde / Tyrell Foreman / Julien Fortier / Andre Fortin / Nancy Foster / Shane Fournier / Patricia Fowler / Daniel Fradette / Roberts Frampton / Jody Francis / Kathleen Franco / Jason Francoeur / Aaron Frank / Lloyd Franklin / Roberta Frankow / Jack Fraser / Jennifer Fraser / Shaun Fraser / Darren Frederick / Karen Freeborn / Natasha Freedman / David Freeman / Larry Freeman / Tammy Freeman / Kyle Freimuth / Kenneth Friesen / Teresa Friesen / Dexter Froehlich / Denise Froese / Eli Frolov / Adam Fry / David Fryett / Murray Fuerst / Shane Fuson / Jeff Gaberel / Ian Gabouda / Kyle Gaetz / Kelly Gagne / Clarke Gagnon / Kody Gagnon / Chad Galbraith / Paula Galbraith / Daniel Galipeau / Glenn Galipeau / Micheal Galipeau / Marie Gallant / Jeremy Gallop / Debbie Gammon / June Gan / Hong Gao / Robert Gardner / Chad Garland / David Gartshore / Nancy Gauthier / Sherlyn Gavronsky / Crystal Geiss / Eric Geppert / Glenroy Gerald / Janice Germain / Dustin Gervais / Kelly Gervais / Michael Gibbs / John Gibson / Kathy Gibson / Travis Gieck / Barry Gilchrist / Brayden Gilewicz / Baljinder Gill / Gurtej Gill / Randolph Gillard / Stanley Gillard / Kenda Gillespie / Keeling Gin / Joel Girard / Simon Gittins / Corina Gladney / Robert Glass / Kimberly Glennie / Charles Gobin / Travis Godfrey / Adam Goehner / David Goldie / Todd Gondek / Gaspar Gonzalez / Darrin Goodheart / Suzanne Goodwin / Cecil Gordon / Heather Gordon / John Gordon / Jennifer Gorman / Lance Gosselin / Jason Goudie / Cathryn Gough / Patricia Goulbourne / Bailey Gould / Sabrina Gould / Marc Goulet / Rene Goulet / Peter Goumans / Colin Gouthro / Andrew Graham / Conrad Grams / Christopher Grant / Michael Greaves / James Grecco / Dale Green / Naomi Green / William Green / Dale Greene / Robert Greenop / Alexander Greenshields / Brent Greenstein / Allan Greeves / Lisa Gregory / Paul Gregory / Kent Greig / Susan Grey / Brent Grieve / Mary Grieve / Jason Griffiths / Jason Grimard / Brian Griswold / Brett Guenther / Douglas Guild / Majahana Gumede / Gurdip Gundara / Subodh Gupta / Ritu Gurjar / Dwayne Gurski / Philip Gwozd / Cheryl Gwynn / Gary Hack / James Haddad / Chad Hadler / Kenneth Hadley / Sheldon Hagen / David Hager / Brian Hagerman / Thomas Haggart / Cindy Halford / Cindy Halim / Cory Hall / Tylor Halonen / Blair Halter / Nicole Haltman / Alison Halyk / Chris Hamel / Lucie Hamel / Donald Hamilton / Kristy Hammermeister / April Hammond / Jaw Han / Lyle Hanch / Tanya Hancock / Lee Hannaford / Liz Hannah / Lesley Hansen / Bradley Hanson / Ryan Hanson / Dhugal Hanton / Leslie Hanton / Valerie Hardman / Danielle Hardy / Lisa Hardy / Robert Harper / Janet Harren / Murray Harrington / Richard Harrington / Daryl Harris / Eugene Harrison / Jason Harrison / David Hart / Lucy Hart / Marianne Hart / Amanda Hartman / Robert Harty / Eugene Harwood / Christopher Haskell / Douglas Haskell / Dave Hassan / Heather Hastie / William Hastie / David Hastings / Hatch / Garrett Hatch / Russel Hatch / Robert Hauca / Murray Hauck / Leslie Hauser / Alicia Hawkings / Ryan Hawkings / Dean Hawkins / James Hawkins / Christopher Hayes / Julia Haynes / Matthew Haysom / Micheal Hayward / Ronald Hazelwood / Dennis Hazzard / Wyatt Heard / Roger Hebert / Joel Heese / Kevin Heffernan / Allan Heidinger / Roy Heise / Delvin Heller / Richard Hellmer / Gary Henault / Bradley Henderson / Kelly Henderson / Shelly Henke / Kurt Hennig / Dawn Henry / Michael Henschel / Trudy Hergert / Jordan Herle / Brent Herman / Kurt Hermann / Jose Hernandez / Orlhay Hernandez / Candice Heron / Dean Herriman / Wayne Hertz / Lucie Herzig / Colin Hibbert / Stephen Hicks / Laura Hider / Laurie Hilkewich / Shane Hillaby / Zepporah Hinton / Stacy Hittel / Ki-Tat Ho / Shawn Hobman / Jeffery Hodder / Tom Hodgins / Corinne Hoebers / Steven Hofer / Julie Hoff / Elise Hoffman / Matthew Hoffman / Darren Hofmann / Larry Hofstetter / Tammy Hogan / William Hogue / Robert Hohls / Yorka Holl / Stephen Hollingshead / Ryan Holmes / Nathan Holsapple / Patricia Holtan / Norman Holtz / Morris Holuk / Claire Hong / Hai Hong / Steven Hoof / Lorna Hopkins / Landon Hopp / Logan Hopp / Glenn Horiachka / Christopher Horkoff / Loreli Hornby / Candice Horne / Tracey Horne / Todd Horsman / Renita Hoskins / Ryan Hoskins / Karin Hossack / Jennifer Houssin / Bonnie Howard / Michael Howard / Christopher Howe / Robert Howe / Kathy Howell / Mark Howell / Randy Hoynick / Glen Hrycauk / Trevor Hrycay / Yumin Huang / Kenneth Huard / Christopher Huber / David Huber / Gregory Huber / Warren Huber / Beverly Hudjik / Jennifer Hudson / John Hudson / Michael Hudson / Joel Hughes / Tim Hughes / Blaine Hujber / Susan Hume / Carmelle Hunka / James Hunt / Ashlee Hunter / Hilary Hurst / Bradley Hurt / Brent Huynh / Nathan Hylton / Laina Hynes / Sheena Hynes / Chad Hyshka / Kevin Hyslop / Sheldon Ibach / Farhang Ighani / Tara Ignacio / Pedro Ilomin / Cheryl Inkster / Jennie Innendorfer / Gamze Ipek / Earl Irwin / Jill Isaak / Troy Ivanics / Dustin Jack / William Jack / Piers Jackman / Antonio Jackson / Kelly Jackson / Kyle Jackson / Sheldon Jackson / Tom Jackson / Rebecca Jacksteit / Sandra Jacob / Michelle Jacobsen / John Jacques / Lynda Jager / Charlene James / Darren James / Jason Jamieson / Lester Janke / Lyle Jans / Nishikant Jawne / Carrie Jeanes / Kenneth Jensen / Peter Jensen / Tammy Jensen / Jennifer Jessome / Jeffrey Jeworski / Dana Jia / Gino Jimenez / Michael Jin / Michael Jin / Norman Jodoin / Sibu John / Stephanie Johner / Brian Johnson / Chad Johnson / Leslie Johnson / Linda Johnson / Michael Johnson / Steve Johnson / Terry Johnson / Johnston / Brad Johnston / Derek Johnston / George Johnston / Michelle Johnston / Nathanial Johnston / Susan Johnston / Tony Johnston / Gary Joncas / Colleen Jones / Janet Jones / Tyler Jones / Nicolaas Jonk / Donald Jordan / Richard Jordan / Kurt Jordheim / Bryan Jory / Peter Joziasse / Julita Junio / Brent Kadler / Joleen Kadler / Lee Kadutski / Paul Kahler / Cody Kallis / Leonard Kampel / Patricia Kananda / Justin Kangarloo / Renae Kapala / Brad Karaja / Charissa Karaszkiewicz / Farahnaz Karimian / Farida Karimova / Milosz Karpinski / Bradley Karpuk / Almas Kassam / Rose Kassamali / Arron Kaura / Nilesh Kawa / Deanna Kealey / Michael Kealey / Bernard Kelly / Brandon Kelly / Darren Kelly / Kevin Kelly / Corrina Kennedy / Patrick Kenney / James Kenny / Shawn Kergen / Stephanie Kerluck / Kyle Keyowski / Geoffrey Keyser / Isaac Khallad / Kimberly Khoury / David Kielstra / Stuart Kilfoyle / Lori Kimoff / Anling King / Margaret Kinsella / Steven Kipta / Wayne Kirk / Benjamin Kis / Nora Kish / Stephen Kisman / Paul Klaassen / William Klassen / Tyler Klatt / Chad Klein / Timothy Klone / Jody Klotz / Sheila Klutz / Dean Kmech / Gordon Knaus / Paul Knight / Shelley Knight / Daniel Knipstrom / Lyle Knowlton / Ronald Knox / Richard Kobetitch / Barry Koch / Russell Koehler / eorge Kohn / Michael Kokorudz / Annette Kolisnyk / Andreas Koller / Garry Kolodychuk / Jeannette Koluk / Sheldon Komodowski / Cameron Kopansky / Brett Kopeck / Jerry Kopeck / Kenneth Kopeck / Carey Kopp / Andrea Korencik-Butler / Clarence Korpan / Timothy Koskowich / Richard Kotowicz / David Kowalchuk / Janelle Kowalchuk / Norman Kowalchuk / Timothy Kowbel / Kenneth Kozak / Camille Kozar-Crittenden / Jack Kraft / Wade Krauss / Alan Krawchuk / Bradley Krawchuk / Mark Kriaski / Ross Krill / Kerry Kryzanowski / Romuald Kuc / Patricia Kudelik / Patricia Kuhn / Keshava Kumar / David Kunetsky / Philip Kunka / Daniel Kunstmann / Janet Kunstmann / Darwin Kuttnick / Douglas Kuwahara / Barton Kwochka / Randy Kyle / Dinh La / Jocelyn Labonte / Julius Laboucan / Chad Lacina / Christopher Lackey / Makstr Lacoursiere / Krystal Laferriere / Donald Lafond / Philip Lafond / Patricia Lafreniere / Shawnda Lahey / Kathryn Lahoda / Danielle Lajoie / Gregory Lakey / Amreen Lakhani / Luc Lalonde / Robert Lambe / Michael Lambert / Erin Lamb-Fauquier / Michelle Landry / Peter Landry / Russell Landry / Frances Lang / Keith Lange / Emilie Langevin-Murray / Stewart Langner / Eric Laplante / Daniel Lapointe / Debra Lapointe / Elizabeth Lappin / Jeffrey Larsen / Lance Larsen / Kirk Larson / Rodney Larson / William Lathrop / Andrew Laturnus / Arthur Laurin / Kyle Lavallee / Shawnene Lavallee / Scott Lavalley / Chris Lawrence / Dean Lawson / Susan Lawson / Mark Laxdal / Brody Laybolt / Jason Lea / Diane Leach / Darryl Leason / Kirk Ledgerwood / Christi LeDrew / Robert LeDrew / Chrystan Lee Wah / Amanda Lee / Benjamin Lee / Betty Lee / Christine Lee / David Lee / Irene Lee / Keith Lee / Reginald Lee / Ronny Lee / Shirley Lee / Tiffany Lee / Brent Leeb / Jeremy Leggatt / Sean Legge / James Leibel / Christian Leith / Chantelle Leliuk / Andre Lemay / Jean-Francois Lemire / Colleen Leong / Irvin Lepp / Anne Lerner / Ashley Leroux / Kelly Lester / Michael Lesyk / Stella Leung / Derek Lewis / Leslie Lewis / Francis L'Henaff / Lionel Li / Gene Libke / Bernadette Ligocki / Melanie Lindholm / Warren Lindland / Carol Lines / Lonnie Lischka / Leslie Liska / Lori Little / Kun Liu / Xiaohuan Liu / Yamei Liu / Hanna Livak / Jack Livingstone / Tannis Liviniuk / Megan Lloyd / Elaine Loades / Terrance Lobe / Conrad Lockhart / Deanna Lodge / Jerry Loewen / Nanette Loewen / Peter Loewen / Susana Loewen / Matt Loggie / Jeffrey Lohnes / Tyrell Lohse / Kathy Lokinger / Milton Lokken / Jianying Long / Sonja Lonson / Michael Loo / Darin Lorenson / Darryl Lorentz / Shelley Louie / Andrea Louise-Martyn / Kenneth Lowe / Shirley Lowe / Christopher Lowes / Yvan Luciuk / Monica Ludwig / Samantha Lui / Keith Lukan / Jeremy Lumgair / Tammy Luong / Darlene Lynch / Holly Lynch / Jeffrey Lypka / Yvonne Ma / Ailsa MacDonald / Leanne MacDonald / Madeleine Macdonald / Robert MacDonald / Cara MacEachern / Jeremy Macht / Brae MacInnis / Craig Mack / Benjamin Mackay / Cheryl MacKenzie / Catherine MacKinnon / Donald MacLeod / Evan MacLeod / Jean Macnab / Cynthia MacQuarrie / Leilani MacQuarrie / Sherry MacRae / Brent MacSween / Lorrie Madore / Jen-Ryan Magbanua / Benjamin Magnus / Colin Magnusson / Michael Maguire / Scott Maguire / Timothy Mah / Roland Mahe / William Maher / Adlai Majer / Benjamin Makar / Shannon Makinson / Nenad Maksimovic / Tyler Maksymchuk / Zenin Malazdrewich / Erica Mallard / Kenneth Mallory / Jonn Malmqvist / Jules Malo / Mark Malouin / Kelvin Manastyrski / Sirish Mandapati / Fred Mandel / Carmen Manning / David Mansfield / Brady Mapstone / Lisa Marchand / Clifford Marcotte / Robert Markle / Ross Markowski / Betty-Jane Marks / David Marks / Rick Marsden / Wade Marsh / Clement Marshall / Megan Marshall / Darryl Martin / Ivan Martinovic / Robyn Marttila / Michael Martynuik / Alice Martynychev / Patricia Maruschak / Shahbaz Masih / Dawneen Massinon / Stephen Mathezer / Jordan Matthews / Ray Matthews / Rex Matthias / Darren Matvichuk / Doug Maurice / Wahidat Mawji / Christopher May / Gerry May / Kevin Mayer / Lawrence Mayo / Ojikeme Mbadiwe / Richard McAlary / David McArthur / Gordon McCaughey / Michael McClay / Scott McClelland / Allan McColm / Laurel McCormack / Rose McCormick / Greg McCuaig / Heddy McCurry / Katherine McCutcheon / John McDonald / Stephen McDonald / David McDougall / Jeremy McDougall / Bradley McFadden / Brad McFarlane / Kenneth McGillivray / Michael McGrath / Bruce McIlroy / Robert McInnis / Shelley McInnis / Jeffrey McIntosh / Sheila McIntosh / Thomas McKee / Rhonda McKinney / Kristi McKinnon / Reed McKinnon / Brian McLachlan / Denise McLaren / Barry McLaughlin / Ryan McLaughlin / Curtis McLean / Troy McLean / Steven McLellan / Donna McLeod / Lewis McLeod / Margaret McLeod / Stewart McLeod / Barbara McMeckan / Christopher McMillan / Heather McMillan / Leslie McMillan / Perry McMillan / Terri McMillan / Sandy McNabb / Malia McNamara / Janice McNeil / Shelley McNeil / Kevin McNutt / Jillian McPhee / Martin McPhee / Jessica McPherson / Neil McRury / Lana Meaney / Kathy Medina / Dustin Meek / Stephen Meerman / Ross Melchin / Daniel Melody / Michael Messer / Bradford Metcalf / Wendy Metcalf / Paul Metz / Glenda Meyer / Paul Meyers / Patrick Michetti / Leonard Mickalyk / Mihajlo Mihajlovic / Hubrecht Mik / John Miles / David Milia / Shylin Miljan / Corey Miller / Deanna Miller / Maureen Miller / Natalie Milligan-Bertin / Robert Mills / Patricia Milne-Davenport / David Minions / Audrey Mirlach / Adrian Mitchell / Brent Mitchell / David Mitchell / Jonathan Mitchell / Larry Mizzau / Delvin Moch / Vijya Modha / Stephen Moffat / Byron Moffatt / Emelyia Moghaddami / Dallas Mohagen / Kerrie Mohninger / David Moisan / Craig Molde / Carolina Molina / Gary Molnar / Lisa Molnar / Karen Montemurro / Ana Montes de Oca / Shari Montgomery / Christopher Moody / James Moon / Royden Moon / Judy Mooney / Pamela Moore / William Moore / John Moorhouse / Anthony Moroney / Patricia Morris / Byron Morrison / Linda Morrison / Mirna Moscoso / Darla Moser / Boyd Mostoway / Lisa Motuzas / Suzy Moutinho / David Mudie / Ryan Mueller / Frank Mueller / Jessica Mueller / Terry Mueller / Daniel MuirLaslo / Anamika Mukherjee / Erin Mullane / Kendra Muller / Richard Muller / David Mullin / Melissa Mullins / Jean Mulumba / Chandy Mung / Alexander Munro / Blake Munro / James Munro / Donald Munroe / Shane Munsch / Brendan Murphy / Calvin Murphy / Keith Murphy / Seamus Murphy / Sean Murphy / Tara Murphy / France Murray / Alisha Musa / Dean Nagy / Eva Nagy / Jeffrey Nail / Paul Nayyar / William Neary / Trevor Neault / Robert Needham / Janice Neil / Stephen Neilson / Bente Nelson / Catherine Nelson / Jayson Nelson / Richard Nelson / Liudmila Netsvetnaya / Peter Neu / Jeffrey Neufeldt / Jessica Neuls / Donna Newlands / Deirdre Newman / Karen Newman / James Newsome / Frances Ng / Henry Ng / Jessica Ng / Charles Ngai / Daniel Nguyen / Denise Nguyen / Joseph Nguyen / Mary Nhan / Jared Nichols / Eric Nicholson / Scott Nicholson / Kathleen Nickless / Edith Nielsen / Miranda Nielsen / Shelley Nielsen / Andrew Nimmo / Tanya Ninovska / Caroline Njage / Shane Noble / Holly Nofield / Raymond Noot / Stacey Norman / Glen Novak / Stacey Nowaczyk / Jodi Noye / Marcela Nunez / Calvin Nurmi / Timothy Nygaard / Ben Nzekwu / Amelia Oakley / Scott Obrigewitsch / Ann O'Byrne / Mario Ochoa / Brian Odell / Ivan Odland / Jason O'Driscoll / Timothy Ogryzlo / Jordan O'Hara / Craig Oke / Aaron Oland / Chris Oliver / Marletta Oliver / Kurtis Olney / Brent Olsen / Dennis Olsen / Dennis Olsen / Kevin Olsen / Tracey Olsen / Wade Olsen / Bradley Olson / Daryl Olstad / Trevor Oltmanns / Phaik Ooi / Rodney Opperman / Grace Or / Richard O'Rourke / Lekan Osanyintola / Sandi Osmachenko / Mansour Osman / Jacqueline Osmond / Eric Overland / Matthew Overton / Catherine Oviatt / Lauree Owchar / Lara Owodunni / Jason Pacholko / Kyle Pacholok / Darby Page / Dwight Pahl / Judith Paisley / Michael Palenchuk / Mark Palman / Brian Palmer / Eusebio Palmisano / Carl Palomaki / Carl Palomaki / George Pan / Sheila Pantuso / Jason Pao / Guy Parisian / Violet Parker / John Parkin / Dan Parliament / Terry Parnell / Coreen Parsons / Randall Pasay / Geoffrey Paskuski / Ravinder Passi / Bhavesh Patel / Chirag Patel / Rashmikant Patel / Susan Patey LeDrew / Christopher Patey / Trilokeshwar Patil / Christopher Patterson / David Patterson / Aaron Patzer / Ajaykumar Pau / Brian Paulson / Journey Paulus / Matthew Pawliw / Kathryn Payne / Darren Pearman / Shane Pearsall / Cassandra Pedersen / David Pedersen / Gary Pederson / Jason Pederson / Stephen Pella / Jennifer Pemberton / Keefe Pendleton / Jennifer Pendura / Xiaohua Peng / Kristina Penney / Randy Penny / Wayne Pennycook / Aaron Penton / Steve Penwarden / Clinton Peredery / Chris Perkons / Shawn Perrault / Brian Peterkin / Anthony Peters / Mitchell Peters / Terry Peters / Jeffrey Petersen / Stacey Petersen / Andrew Peterson / Ernest Peterson / Lowell Peterson / Robert Peterson / Troy Peterson / Veronica Petri / Leslie Petrie / Michael Petrock / Peter Petrucci / Matthew Pettipas / Dwayne Pfeifer / Fan Pfeifer / Martin Pflug / William Phee / Christie Phelan / Linda Phelan / Alana Phillips / Darren Phillips / Grant Phillips / James Phillips / Kevin Phillips / Linna Phu / Danny Picard / Leonardo Piedimonte / Ella Pierrot / Karen Pihl / Avery Pikowicz / Robert Pilon / Simon Pinto / Trevor Pipke / Kenneth Pischke / Rob Pitchford / Shawn Pitre / Hughie Pittman / Michael Pittman / William Pittman / Ronald Plante / Brent Plato / Michael Plettell / Jayce Plouffe / Lee Poirier / Brenda Poitras / Joseph Poitras / Connie Pokiak / Andre Politylo / Kevin Pollock / Robert Pollock / Ronald Polzen / Logan Popko / Glen Porter / Derek Potts / Veronica Potts / Thomas Power / Amit Prabhu / Riwan Prasatya / Claude Prefontaine / Michael Preston / Edward Preville / Carol Price / Elaine Price / Glenn Price / Tyler Price / Darren Prior / Gerald Prosper / Jacob Prosser / Jerome Proulx / Ryan Proulx / Murray Pryor / Sharon Pudwell / Kirsten Pugh / Thomas Pugh / Steven Pullano / Scott Pura / Ann Purdy / James Purnell / Trad Pushie / Michael Putnam / Lin Qi / Ping Qiang / Jennifer Quach / Anthony Quan / Samuel Quantz / Sonia Quattrucci / Judy Quinn / Kathryn Quintal / Samuel Quiring / Samuel Quiroga / Erin Radloff / Jason Raemer / Steve Raffa / Sharon Rainey / Gina Rajic / Lori Ramey / Ursula Ramsey / Gail Randell / Marc Ranger / James Rankin / Kevin Rappel / Kevin Rappel / Leah Rappel / Daryl Rasmussen / Kelly Rasmussen / Perry Rasmussen / Adrian Rau / Corrine Rault / Eileen Rawlyk / Gideon Razemba / Matthew Read / Guy Reader / Nicole Redekop / Alexander Reed / Michelle Reed / Lisa Regan / Floyd Regner / Alan Reid / Bryon Reid / Callie Reid / Collin Reid / Gwen Reid / Heather Reid / Vicki Reid / Paul Reimer / Douglas Rein / Andrew Reinke / Shaida Remtulla / Alain Renaud / Wayne Resch / Jonah Resnick / Craig Reszel / Justin Reti / Joanne Rex / Wayne Reynolds / Rodney Rhodes / Grant Ribey / Allan Richard / Christopher Richard / Scott Richardson / Dean Riddell / Dean Riddell / Jason Riddell / Brendan Rieder / Gerard Rieger / Helen Rignault / Robert Ringuette / Shaun Riome / Michael Ripley / Kevin Ripplinger / Christopher Rivest / Brian Rivoire / Dustin Rizzoli / Angelo Rizzuto / Greg Robbins / Reid Roberge / Joanne Roberts / Shirley Roberts / Suzanne Roberts / Jared Robertson / Neil Robertson / Marlin Robins / David Robinson / Heather Robinson / Matthew Robinson / Simon Robinson / Tony Robinson / Travis Robinson / William Robinson / Brian Roche / Pamela Rocuant / Craig Rodine / Alan Roessel / Doug Rogoschewsky / Melanie Rogoski / Bradley Rolfe / Stephanie Rolseth / Kathryn Roman / Peggy Ronald / Patricia Rose / Brian Rosin / Dave Rossiter / Leor Rotchild / Shaun Roth / Shaun Roth / Lisa Rothwell / David Rough / Robert Rovers / Jeffrey Rowbottom / Kathy Ruhe / Arron Rush / Jeremy Rushton / Bruce Russell / Lynette Russell / Ivor Ruste / Daniela Ruzdijic / Duane Ryan / Brandon St Jean / Jessica Sabourin / Noushin Sadeghpour / Andrew Sadler / Gregory Sadler / Ronnie Sadorra / Marvin Sagert / Aldrich Salazar / Raheleh Salehi Mojarad / Lindsay Salt / Sari Salt / Robert Salyn / Farida Samji / Sharon Sampson / Ryan Samuel / Geoffrey Sander / Maureen Sander / Wayne Sandmaier / Sigfrid Santiago / Brian Sartison / Chris Saunders / Patrick Sauve / Karen Savinkoff / Matthew Savoia / Marcel Savoie / Craig Sawchuk / Coral Sawkins / Brian Sayer / Andrea Scaffo-Migliaro / Luciano Scarpino / Brandee Scarrott / Susan Schaar / Kimberly Schacher / Harry Schaepsmeyer / Matthew Schamber / Ricky Scharf / Gary Scheifele / Evan Scheuerman / William Scheuerman / Dan Schiller / Randolph Schiller / Lana Schlosser / Erin Schmaltz / Rodney Schmidek / Brian Schmidt / Joel Schmitz / James Schmunk / Christopher Schneider / Lindsey Schneider / Mark Schneider / Robert Schneider / Wesley Schneider / William Schneider / Gerry Schnell / Brian Scholten / Darrell Schuetzle / Loris Schuetzle / Glen Schultz / Troy Schwab / Eleanor Scott / Erin Scott / Kaylee Scott / Stephen Scott / Shannon Secreti / James Sedger / Brent Seib / Henry Seifried / Brad Seipp / Carl Seitz / Steven Sellers / Nikki Sereres / Matthew Serfas / Donald Serink / James Setla / Rami Shabaneh / Travis Shackleton / Ali Sharif / Cary Shaw / Joni Shaw / Susan Shaw / Beverly Shea / Brenda Shepherd / Michael Shepherd / Amie Sherwin / Yi Shi / Corey Shideler / Karen Shillingford / Ernest Sholtz / Andrew Sick / Mario Sicolo / Navjeet Sidhu / Kyle Silbernagel / Jane Simington / Rodney Simmons / Angela Simpson / Cindy Simpson / Ken Simpson / Lorelie Simpson / Malcolm Simpson / Shelly Simpson / Connie Sin / Greg Sinclair / Mathew Sinclair / Melanie Sinclair / Travis Singer / Gurpreet Singh / Usha Singh / James Sinnaeve / Song Sit / Zyg Siwy / Vladimir Sizov / Justin Sjogren / Martin Skaalrud / Karen Skrocki / Terrance Skrypnek / Jared Slater / Joel Slobogian / Derek Smale / Brad Small / Steven Small / Scott Smart / Stuart Smiley / Ryan Smilski / Amanda Smith / Everett Smith / Jennifer Smith / Jeramie Smith / Karen Smith / Kerry Smith / Kristin Smith / Lindsay Smith / Maxwell Smith / Mervin Smith / Ronald Smith / Sarah Smith / Stephen Smith / Dennis Sneider / Cameron Snyder / Gregory Sobchyshyn / Kristi Soderman / Kristin Soffer / William Soini / Jamie Solland / Kerrie Somerville / Michael Somerville / Arun Sood / Bradley Sorenson / Elias Soto / Janet Soucy / Michael Sparkes / Dwayne Spelay / David Speltz / Jordan Spencer / Janie Spenst / Jacqueline Sperle / Stanley Spiers / Dan Spitzer / Laurel Spivak / Elizabeth Springer / Rudy Sprunger / Richard Squires / Jason St Amant / Paul St Amant / Kelly St. Germain / Darwin Stainbrook / William Stait / Travis Stambaugh / Gary Stangl / Shawn Stangness / Mark Stappler / Katherine Stavropoulos / Lisa Stebbins / Robert Steele / John Steeves / Kathleen Steiert / Lisa Stein / Craig Stenhouse / Wayne Stenhouse / Trevor Stensby / Kristjan Stephansson / Blake Stevens / Brian Stevens / Jeffery Stevens / Sandra Stevens / Nicole Stewart / Raegan Stewart / Sydnee-Leigh Stewart / James Stirling / Shawn Stobbart / Dean Stobo / Linda Stock / Darryll Stone / William Stoneman / Jeremy Stork / Kevin Stoski / Andrew Straile / Darcy Strate / Gregory Stratychuk / Brenda Streight / Lionel Stuber / Joshua Studer / Krystle Suchan / Jennifer Suen / Vitali Sukhetsky / Arjan Sulejmani / Jeffery Sullivan / Justin Sullivan / Sarah Sullivan / Colette Summers / Susan Sun / Rudy Sundermann / Judy Sutton / Benjamin Svoboda / Colyn Swanson / Darren Swaren / Tara Sweet / Joseph Swiech / Elizabeth Swift / Ken Switala / Jason Switzer / Donald Swystun / Ryan Sych / Mark Sykes / Jared Sylvestre / Pierre Sylvestre / Michael Taillon / Carla Tait / Neil Talbot / David Tam / Jennifer Tamura / Vernny Tang / Cody Taranko / Evan Tardif / Debra Tario / John Tarnasky / Landon Tarnasky / Ross Tarrant / Cameron Taylor / Scott Taylor / Sheila Taylor / Gary Tebb / Shane Tebb / Brittany Tebbenham / Paul Teha / Robert Templeton / Darwin Terlson / Mitchell Thew / Sharon Thiara / Bradley Thiessen / Tyler Thiessen / Wayne Thomas / Christopher Thompson / Cody Thompson / Joel Thompson / Linda Thompson / Marion Thompson / Ryan Thompson / Scott Thompson / Melanie Thomson / Evelyn Thorkelson / Brenda Thorne / Nishi Thusoo / Bryan Tiessen / Robbie Tinis / James Todd / Matthew Toews / Scott Toews / Scott Toews / Steven Tofan / Jillian Tofer / Dubravka Tomic / Shannon Tompkins / Henry Tong / Alfredo Torres / Gabriel Toth / Donnie Tradewell / Jennifer Tran / Kim Tran / Lisa Trang / Nathaniel Tredger / Leslie Tremblay / Russell Tremblay / Richard Trost / Sharon Trottier / Johanne Trudel / Colin True / Warren Trumpour / Hoa Tsukishima / Carla Tucker / Lana Tucker / Catherine Tully / Gurpartap Tumber / Jean Turcotte / Dean Turner / Julia Turner / Ryan Turtle / John Turuk / Chandip Twana / Alister Twarzynski / Kerri Twemlow / Barney Twidale / Keith Urlacher / Luis Urzua / Gordon Uswak / Tamara Utsch / Teresa Utsunomiya / Mora Uyesugi / Stephen Uzelman / Petrica Vaitus / Paul Valcourt / Jason Van Buskirk / Shane Van Buskirk / Mark Van de Veen / Brent Van Ham / Jeffrey Van Ham / Charlotte Van Pelt / Kerry Van Son / Angela Van Unen / Kimberly Van Unen / Cheryl VanBastelaar / Arthur Vander Hoek / Paul Vander Valk / Kelly Vandesype / Tony Vandeweyer / Justin VanMaarion / Tyson Vany / Theresa Varalta / Erika Vargas / Adam Varley / John Varsek / Greg Vatcher / Cody Vaughan / Haig Vejprava / Bernadette Velasco / Lazar Velev / Darren Venne / Natasha Verdon / Jerrod Verhaest / Michael Vermeersch / Mike Verrier / Wilhelmina Versloot / Brian Verville / Jillian Viccars / Sheldon Vigoren / Leonidas Villegas / Ryan Vinck / Shaireen Virani / Phonesavanh Viravong / Lori Virtue / John Visser / Raymond Von Niessen / Cindy Wachtler / Sean Wade / Lee Wagner / Steven Wagner / Heather Wagstaff / Vivian Wahby / Duane Walkeden / Twila Walkeden / Kirstin Walker / Rennick Walker / Taura Walker / Sheldon Wall / Steven Wall / Steve Wallace / Tarnia Wallace / Hayward Walls / Ryan Walper / Andrew Walsh / Andrew Walsh / Tieshan Wang / Corwin Wanuch / Darcey Ward / Michelle Ward / Kathleen Ware / Allison Warkentin / Anthony Warren / Darryl Warren / Scott Waschuk / Kitty Wasslen / Michael Wasylyk / Michele Waters / Jayson Watier / Jeff Watier / Catherine Watson / Robert Watson / Robert Watson / Rick Watters / Katherine Wattie / Arlette Watwood / Richard Wawrykowych / Evan Way / Loy Webb / David Webber / Pamela Weber / Paul Weber / Colin Webster / Dale Webster / Pamela Webster / Rodney Webster / Richard Wegerhoff / Heather Weighill / Betty Weightman / Ryan Weimer / Simon Weintz / Shawna Weir-Murphy / Lyle Weiss / Lyle Weiss / Neil Wenman / Michael Wenner / Sara Wentz / Gregory Wenzel / Trevor Weppler / Nigel Werenka / Margaret Werezak / Scott Werre / Barry Weseen / Dann Weselosky / Jeff West / Patricia Westman / Trevor Westman / Bradley Wheeler / Deanne Wheeler-Felstad / Colleen Whelehan / Charles Whitaker / Curtis White / Mergitte White / Vanessa White / William White / Lorna Whiteway / Albert Whitford / Jack Whittaker / Phoinyx Whittingham / Carol Whorms / Carol Whorms / Jeneane Whyte / Russell Wickes / Catherine Widdoes / Michael Wiebe / Trevor Wiebe / Linda Wiegand / Ralph Wieler / Brett Wiens / Lane Wieteska / Becky Wigemyr / Lori Wilhelm-Einsporn / Candise Wilkins / Frederick Wilkinson / Jessica Wilkinson / Karen Will / Adam Willcott / Cory Williams / Larry Williams / Tyler Williams / Darryl Williamson / John Williamson / Caroline Wilson Mussbacher / Carrie Wilson / Cedric Wilson / Frances Wilson / Jeffrey Wilson / Micheal Wilson / Robert Wilson / Russell Wilson / Shauna Wilson / Cory Winder / Henry Winnicki / Allan Winquist / Nathan Winter / Riley Winter / Gary Witiw / Dean Wolansky / Cindy Wolfe / Murray Wolfe / William Wolfe / John-Paul Wolff / Dale Woloshen / Benjamin Wong / Jim Wong / Lucia Wong / Deanna Woo / Kevin Woo / Blake Wood / Nicole Woodland / Mary Woods / Troy Woods / Garfield Woodward / Caroline Worobo / Rachelle Woroniuk / Leonard Wourms / Darin Wright / Stan Wright / John Wrobel / Xinjie Wu / Kerry Wycislik / Brent Wyness / James Yaholnitsky / Daniel Yake / Robert Yanke / Robert Yanke / Jessica Yarnell / Kim Yee / Larry Yee / Tony Yee / Sung Youn / Darla Young / Elizabeth Young / Ian Young / Janet Young / John Young / Rodney Young / William Young / Alice Yu / Carolyn Yu / David Yu / Tze Yu / Luningning Yue / Nicole Yuen / Arthur Yukim / Trenton Zacharias / James Zakariasen / Maliha Zaman / Roger Zavagnin / Mohamud Zaver / Sandra Zdunich / Khalil Zeidani / Remo Zelantini / Jason Zelinski / Amy Zhang / Weimin Zhang / Yi Zhang / Ian Ziebart / Russ Ziegler / Drew Zieglgansberger / Oral Zihove / Melissa Zimmerman / James Zinger / Ronald Zittel / Lynette Zyznomirski

AS AT DECEMBER 31, 2010

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The members of the Cenovus Board of Directors have years of experience. Their breadth of skills guides our decisions and actions.

DIVERSE EXPERTISE + QUALITY DISCUSSION = **INSIGHTFUL GUIDANCE**

(Pictured left to right)

CHARLES M. RAMPACEK
PATRICK D. DANIEL
MICHAEL A. GRANDIN (Board Chair)

RALPH S. CUNNINGHAM
IAN W. DELANEY
VALERIE A.A. NIELSEN

BRIAN C. FERGUSON
WAYNE G. THOMSON
COLIN TAYLOR

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"Your Executive Team and your Board are off to a strong start in realizing the great potential that is Cenovus."

GOOD GOVERNANCE + STRATEGIC DECISIONS = **A COMPANY TO BELIEVE IN**

MICHAEL A. GRANDIN
BOARD CHAIR

"After reading this annual report, I think you will agree that Cenovus's first year performance couldn't have been much better."

WHAT A GREAT START FOR CENOVUS!

Cenovus began with an excellent portfolio of assets. It has vast and largely undeveloped oil sands resources to provide for growth well into the future. It has established oil and natural gas assets to fund this growth. It has the technical know-how to effectively recover its resources and the project management expertise to do so efficiently. Perhaps most importantly, it has a highly engaged and enthusiastic workforce, motivated by attractive opportunities, whose members are eager to convert potential value into present value.

After reading this annual report, I think you will agree that Cenovus's first year performance couldn't have been much better.

From a governance perspective, we believe that the Board got off to a great start as well. The management proxy circular describes, in some detail, your Directors' qualifications and your Board's actions with respect to regulatory compliance, self-regulation, executive compensation and other important Board and Committee matters. However, I thought a few comments here might give you a better understanding of how your Board is operating.

We have a nine-member Board with a good mix of skills. The smaller size is intended to encourage open and inclusive discussion. The mix of skills captures experience in both upstream and downstream oil and gas operations and transportation, as well as in accounting, finance and general business and board operations. This combination leads to good quality debate and questioning based on knowledge of the business, all with a view to helping the Executive Team make high-quality decisions.

During the year, we focused much of our attention on strategy and risk management. We worked with the Executive Team to ensure that Cenovus's initial strategy built on the rationale for the company's creation and took full advantage of its physical asset base, the technical expertise of its people and its financial capacity. At the same time, and also with the Executive Team, we made sure all the risks that we could foresee were included in Cenovus's well-developed risk monitoring and mitigation system.

For reasons such as these we believe your company, your Executive Team and your Board are off to a strong start in realizing the great potential that is Cenovus.

Respectfully submitted on behalf of the Board.

OPERATING HIGHLIGHTS

BEFORE ROYALTIES	2010	2009	% change
Production			
Crude Oil and Natural Gas Liquids (bbls/d)			
Oil Sands – Heavy Oil			
Foster Creek	**51,147**	37,725	36
Christina Lake	**7,898**	6,698	18
Total	**59,045**	44,423	33
Pelican Lake	**22,966**	24,870	(8)
Senlac	**–**	3,057	–
	82,011	72,350	13
Conventional Liquids			
Heavy Oil	**16,659**	17,888	(7)
Light and Medium Oil	**29,346**	30,394	(3)
Natural Gas Liquids	**1,171**	1,206	(3)
Total Crude Oil and Natural Gas Liquids (bbls/d)	**129,187**	121,838	6
Natural Gas (MMcf/d)	**737**	837	(12)
Refinery Operations(1)			
Crude Oil Capacity (Mbbls/d)	**452**	452	–
Crude Oil Runs (Mbbls/d)	**386**	394	(2)
Crude Utilization (%)	**86**	87	(1)
Proved Reserves(2)(3)			
Total Reserves (MMBOE)	**1,666**	1,398	19
Year-end Bitumen Reserves (MMbbls)	**1,154**	866	33
Total Production Replacement (%)	**398**	205	94
Recycle Ratio(4)	**7.8**	5.1	53
Proved Finding & Development Costs ($/BOE)(5)	**3.65**	5.39	(32)
Reserve Life Index (years)	**18**	15	20

(1) Represents 100% of the Wood River and Borger refinery operations.

(2) Natural gas is converted using a 6:1 oil equivalent. See the Advisory section of the MD&A.

(3) 2009 estimates prepared in accordance with U.S. disclosure requirements using constant prices and costs. 2010 estimates prepared in accordance with Canadian disclosure requirements using forecast prices and costs. See the Oil and Gas Reserves and Resources section of the MD&A for more information.

(4) For additional information regarding our Recycle Ratio, see our 2011 Management Proxy Circular, available at www.cenovus.com.

(5) Finding and Development Costs presented do not include changes in future development costs. For a description of the calculations used, refer to our Additional Advisory on page 132. Finding and Development Costs calculated with changes in future development costs, for proved reserves and for proved plus probable reserves, are disclosed in the Additional Advisory on page 132.

FINANCIAL HIGHLIGHTS

$ MILLIONS, EXCEPT PER SHARE AND OTHER AMOUNTS AS NOTED	2010	2009	% change
Gross Revenues	**13,422**	11,790	14
Net Revenues	**12,973**	11,517	13
Cash Flow(1)	**2,415**	2,845	(15)
Per Share – Diluted	**3.21**	3.79	
Net Earnings	**993**	818	21
Per Share – Diluted	**1.32**	1.09	
Operating Earnings(1)	**794**	1,522	(48)
Per Share – Diluted	**1.06**	2.03	
Capital Investment	**2,122**	2,162	(2)
Net Acquisition and Divestiture Activity	**(221)**	(219)	
Net Capital Investment	**1,901**	1,943	(2)
Dividends Per Common Share ($/share)(2)	**C$0.80**	US$0.20	
Dividend Yield (%)(3)	**2.40**	3.17	
Debt to Capitalization (%)(1)	**26**	28	
Debt to Adjusted EBITDA (times)(1)	**1.2**	1.1	

(1) Non-GAAP measures as referenced in the Advisory section of the MD&A.

(2) Fourth quarter dividend paid in December 2009 reflects an amount determined in connection with the Arrangement (defined on page 36) based on carve-out earnings and cash flows.

(3) 2010 based on TSX closing share price at year end. 2009 based on NYSE closing share price at year end and using annualized dividend.

For the Year Ended December 31, 2010

(Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated February 18, 2011, should be read with our audited Consolidated Financial Statements for the year ended December 31, 2010 ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this document, see the Advisory at the end of this MD&A.

Management is responsible for preparing the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviews the MD&A and recommends its approval by the Board.

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency is indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and reserve volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

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Introduction and Overview of Cenovus Energy

Cenovus is a Canadian oil company headquartered in Calgary, Alberta, with a market capitalization of approximately $25 billion on December 31, 2010. In 2010, we had total crude oil, natural gas and NGL production in excess of 250,000 barrels of oil equivalent per day.

Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca region is our Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S.A., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel to reduce volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase production, predominantly from Foster Creek and Christina Lake as well as Pelican Lake and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach and our conventional crude oil and natural gas production base is expected to generate reliable production and cash flows which will enable further development of our oil sands assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to continuous innovation. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to minimize surface land disturbance.

Our future lies in developing the land position that we hold in the Athabasca region in northeast Alberta. In addition to our Foster Creek and Christina Lake oil sands projects, we currently have three emerging projects in this area:

	Ownership Interest
Narrows Lake [(1)]	50 percent
Grand Rapids	100 percent
Telephone Lake	100 percent

(1) Approximate ownership interest

At our Narrows Lake property, located within the Christina Lake Region, we have submitted a joint application and environmental impact assessment ("EIA"). This project is expected to begin producing in 2016, and is expected to have a gross production capacity of 130,000 bbls/d. At our Grand Rapids property, which is located within the Greater Pelican Region, a pilot project is underway. If this pilot is determined to be successful, we expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 bbls/d. Our Telephone Lake property is located within the Borealis Region. We have submitted a regulatory application for the development of this property, including the construction of a facility with gross production capacity of 35,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands, most of which is undeveloped. Our 10 year business plan is to grow our net oil sands production from approximately 60,000 bbls/d in 2010 to 300,000 bbls/d by the end of 2019. Growth is expected to be primarily internally funded through cash flow generated from our established crude oil and natural gas production base where we also have opportunities to add production through new technologies. Our natural gas production provides an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned 2011 coker startup of the Coker and Refinery Expansion ("CORE") project at the Wood River refinery. We also employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful dividends to deliver strong total shareholder return over the long term.

OUR BUSINESS STRUCTURE

Our operating and reportable segments are as follows:

- **Upstream,** which includes Cenovus's development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
  - **Oil Sands,** which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips and operated by Cenovus.
  - **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.
- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations,** which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above were changed from those presented in prior periods to better align with our long range business plan. All prior periods have been restated to reflect this presentation.

2009 FINANCIAL INFORMATION

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana and the other an oil company, Cenovus.

The results for the year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent the Company's operations, cash flow, and financial position as a stand-alone entity. The results for the periods prior to the Arrangement, being January 1 to November 30, 2009 and January 1 to December 31, 2008 have been prepared on a "carve-out" accounting basis whereby results have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. Further information on the carve-out assumptions can be found in the notes to the Consolidated Financial Statements.

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Overview of 2010

2010 marked our first full year operating as an independent company, and we delivered very strong performance overall.

Excellent operating performance reflected strong oil sands production growth, with very good operating and capital cost controls to maintain our position as a low cost producer. Despite diminished realized natural gas prices, which resulted from the large oversupply of natural gas markets and crude oil pipeline disruptions, both of which impacted our operating cash flows, we achieved our 2010 cash flow guidance and generated net earnings of $993 million which exceeded 2009 by 21 percent. In addition, managing our business with a continual focus on value creation, cost control and updated credit facilities resulted in Cenovus having an even stronger financial position at the end of 2010 than at the start of the year.

Specific highlights for 2010 include:

- Substantial growth in our bitumen proved reserves (year-over-year increase of 288 MMbbls), resulting in very low finding and development costs;
- Production from our Foster Creek and Christina Lake oil sands projects increasing by 33 percent;
- Receiving regulatory approval for Foster Creek expansion phases F, G and H;
- Capital spending on the Foster Creek and Christina Lake expansions increasing significantly, consistent with our strategy to move these projects forward; and
- Our Conventional crude oil and natural gas business generating more than $1.2 billion in operating cash flow in excess of the related capital spent to fund the development of our oil sands projects.

Additional operating and financial highlights for 2010 compared to 2009 include:

- Total capital spending being relatively unchanged year over year, however, spending on our oil sands projects increased 38 percent to $867 million while spending on our refineries decreased 37 percent to $655 million. In our Conventional upstream business, our spending focus on oil increased to 68 percent of spending ($358 million) in 2010 compared to 48 percent ($223 million) in 2009;
- Proceeds from the divestiture of property, plant and equipment totaled $307 million (2009 - $222 million);
- Net revenues increasing 13 percent mainly due to improved crude oil and refined product prices despite pipeline transportation disruptions of crude oil from Alberta to mid-west U.S. refineries in the second half of 2010 and higher royalties as a result of Foster Creek achieving payout status for royalty purposes;
- As expected, based on realized natural gas prices declining 34 percent and natural gas volumes declining 12 percent (including the impact of divestitures) we had a decrease in our Upstream operating cash flow of $921 million. The lower natural gas prices and lower operating cash flow from Refining and Marketing resulted in decreases to our cash flow of $430 million and operating earnings of $728 million. The natural gas decreases were partially offset by higher crude oil volumes and realized prices;
- Operating cash flow from Refining and Marketing decreasing by $293 million mainly due to planned turnarounds at both refineries, higher average crude costs and refinery optimization activities due primarily to weaker diesel and gasoline prices primarily in the first half of 2010. Partially offsetting these decreases were lower operating expenses and a strengthening of the Canadian dollar;
- Net earnings increasing $175 million mainly due to unrealized foreign exchange gains, unrealized mark-to-market hedging gains and lower income taxes, partially offset by lower operating cash flows;
- Our debt metrics improving with debt to capitalization decreasing to 26 percent and debt to adjusted EBITDA being 1.2x; and
- Declaring and paying dividends of $601 million ($0.20 per share per quarter) in 2010 compared to US$150 million in 2009 paid in connection with the Arrangement.

Reserves and Resources

The receipt of Alberta Energy Resources Conservation Board ("ERCB") regulatory approval for expansion phases F, G and H at Foster Creek, including expansion of the development area, combined with an overall increased recovery factor in the area, has resulted in a significant increase to our proved bitumen reserves in 2010. In 2010, we also issued two news releases highlighting detailed information related to our bitumen initially-in-place, contingent resources and prospective resources, which enable investors to more fully understand our inventory of oil sands assets.

We also provided further information about our resources and development plans at our Investor Day presentations in June 2010 and at the end of 2010 the estimates of bitumen contingent and prospective resources were updated. Our best estimate bitumen contingent resources at December 31, 2010 were approximately 6.1 billion barrels and our best estimate bitumen prospective resources were approximately 12.3 billion barrels.

Foster Creek

Our Foster Creek property achieved project payout for royalty purposes in February 2010. Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. As a result, Foster Creek's royalties increased from $19 million and an effective royalty rate of 2.7 percent in 2009 to $165 million and an effective royalty rate of 16.2 percent in 2010, which includes pre-payout royalties for one month.

As noted above, we received regulatory approval from the ERCB for the next three expansion phases at Foster Creek, F, G and H. When all three phases are complete, Foster Creek's gross production capacity is expected to increase from the current 120,000 bbls/d to 210,000 bbls/d. The next step for these expansions is to receive final partner approval, which is expected in 2011. Engineering and preliminary ground work on phase F is already underway. First production for phase F is expected to be accelerated by 12 months to 2014 compared to our original plan. Production from the other two phases is expected in 2016-2017.

Christina Lake

The construction of the Christina Lake expansion is progressing with phases C and D each expected to add an additional 40,000 bbls/d of gross production capacity. Start up of phase C is expected to begin with steam injection in the second quarter of 2011 and production commencing in the second half of 2011. Production from phase D has been advanced from its original planned start by approximately six months and is now targeted to begin in 2013. These expansion phases are expected to bring Christina Lake's gross production capacity to 98,000 bbls/d in 2013.

New Resource Plays

We have announced our intention to move ahead with the development of Narrows Lake, which may use a combination of SAGD and Solvent Aided Process ("SAP") to recover the bitumen. SAP is a technological improvement applied to our SAGD operations that helps maximize the amount of bitumen recovered and requires less steam and water usage. SAP takes the benefit of injecting steam in the SAGD process and combines it with solvents, such as butane, to help bring the bitumen to the surface. In the first quarter of 2010, we initiated the regulatory approval process by filing proposed terms of reference for an EIA and began public consultation for the project. In the second quarter of 2010, final terms of reference were issued by Alberta Environment and a joint application and EIA was filed.

In 2010, we received approval from the ERCB and Alberta Environment to begin a pilot project at our Grand Rapids project. The drilling of a SAGD well pair and construction of associated facilities is complete and steam injection commenced in December 2010.

As part of our efforts to progress these emerging projects, in 2010, we significantly increased our spending to $124 million in new resource play areas including the drilling of over 150 gross stratigraphic wells and commencing our Grand Rapids pilot project. In addition, we continued our research and development efforts that we expect will continue to reduce our land footprint, water use and air emissions intensity.

Refining CORE Project

At the end of 2010, the CORE project progressed to approximately 91 percent complete from 71 percent at the beginning of the year. Commissioning of several of the process units has been completed with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

Net Capital Investment

Unusual weather patterns across our operating areas throughout the year, including a very wet summer, restricted access to our properties and with continued low commodity prices we chose to reduce spending, which has resulted in our upstream capital investment program being lower than originally planned in some of our operating areas. Although upstream capital spending is lower than expected, production levels have remained at expected levels. Our refining capital spending was also lower than expected as unusually high water levels on the Mississippi River delayed deliveries of various CORE modules, deferring some 2010 spending to 2011. As part of our ongoing portfolio management strategy, we divested of certain non-core oil and gas assets for proceeds of $221 million, which reduced our 2010 crude oil and NGLs production by approximately 975 bbls/d (one percent) and natural gas production by approximately 33 MMcf/d (four percent). In total, our 2010 property, plant and equipment divestitures resulted in proceeds of $307 million.

Net Revenues

During the second half of 2010, pipeline disruptions and apportionment challenges restricted the access of Alberta crude oil to U.S. markets. As a result, there were higher inventory levels of WCS and a widening of the WTI-WCS price differential in the second half of 2010. The widened WTI-WCS differential had a negative impact on our upstream revenue; however our refining operations benefitted somewhat due to a lower cost for purchased product. While the effects of pipeline apportionment did not significantly affect our production, it did result in lower sales volumes in the second half of 2010 as we added volumes to storage at the end of 2010.

With respect to commodity prices, our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows and therefore commodity price hedging activity continues to be an important element of our business model. This activity reflects our objective of locking in prices on a portion of our natural gas and crude oil production such that we protect a significant portion of the subsequent years' cash flows. Realized after-tax hedging gains of $199 million during 2010 (2009–gains of $804 million) reflect the benefits of locking in commodity prices in excess of the current period benchmark prices. These realized hedging gains are significantly less than those of 2009 since they effectively reflect the significant over supply and deterioration of natural gas markets and prices over the last two years. Our hedging strategy continues to be sound and allowed us to put in place natural gas hedges for 2010 at approximately $6.00 per Mcf as compared to hedges for 2009 put in place at approximately $9.00 per Mcf when future prices were higher in 2008. For more information on our realized hedging prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

OUR BUSINESS ENVIRONMENT

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding our financial results.

SELECTED BENCHMARK PRICES[1]

	2010	**Q4**	**Q3**	**Q2**	**Q1**	2009	Q4	Q3	Q2	Q1	2008
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate											
Average	**79.61**	**85.24**	**76.21**	**78.05**	**78.88**	62.09	76.13	68.24	59.79	43.31	99.75
End of period spot price	**91.38**	**91.38**	**79.97**	**75.63**	**83.45**	79.36	79.36	70.46	69.82	49.64	44.60
Western Canada Select											
Average	**65.38**	**67.12**	**60.56**	**63.96**	**69.84**	52.43	64.01	58.06	52.37	34.38	79.70
End of period spot price	**72.87**	**72.87**	**64.97**	**61.38**	**70.25**	71.84	71.84	59.76	59.12	42.69	35.40
Average Price – Differential WTI-WCS	**14.23**	**18.12**	**15.65**	**14.09**	**9.04**	9.66	12.12	10.18	7.42	8.93	20.05
Condensate (C5 @ Edmonton)	**81.91**	**85.24**	**74.53**	**82.87**	**84.98**	61.35	74.42	65.76	58.07	46.26	106.22
Average Price – Differential WTI-Condensate (premium)/discount	**(2.30)**	**–**	**1.68**	**(4.82)**	**(6.10)**	0.74	1.71	2.48	1.72	(2.95)	(6.47)
Refining Margin 3-2-1 Crack Spread[2] *(US$/bbl)*											
Chicago	**9.33**	**9.25**	**10.34**	**11.60**	**6.11**	8.54	5.00	8.48	10.95	9.75	11.22
Midwest Combined (Group 3)	**9.48**	**9.12**	**10.60**	**11.38**	**6.82**	8.09	5.52	8.06	9.16	9.62	11.03
Natural Gas Prices											
AECO *($/GJ)*	**3.91**	**3.39**	**3.52**	**3.66**	**5.08**	3.92	4.01	2.87	3.47	5.34	7.71
NYMEX *(US$/MMBtu)*	**4.39**	**3.80**	**4.38**	**4.09**	**5.30**	3.99	4.17	3.39	3.50	4.89	9.04
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.40**	**0.28**	**0.78**	**0.32**	**0.19**	0.40	0.19	0.67	0.39	0.35	1.23
Foreign Exchange											
Average US/Canadian dollar exchange rate	**0.971**	**0.987**	**0.962**	**0.973**	**0.961**	0.876	0.947	0.911	0.857	0.803	0.938

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. For our realized sales prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

The global economic recovery that began in the second half of 2009 continued throughout 2010 resulting in increased crude oil demand, mainly from China, other Asian countries and the United States, and was reflected in higher WTI benchmark prices. The closing price of WTI at the end of 2010 increased 15 percent from the 2009 closing price and was more than double the 2008 closing price. While crude oil demand increased compared to 2009 and global production levels from both OPEC and non-OPEC countries has increased, significant spare OPEC production capacity still remained at the end of 2010. Further increases in OPEC production could result in a lowering of crude oil prices. WTI is an important benchmark as it is also used as the basis for determining royalties for a number of our crude oil properties.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. The widening of the WTI-WCS differential in 2010 was partially the result of pipeline transportation disruptions of crude oil from Alberta to mid-west U.S. refineries as well as refinery downtime in certain regions of the U.S. in the second half of 2010. While overall the price of WCS increased in 2010 compared to 2009, pipeline disruptions resulted in increased WCS inventory which negatively impacted its market price. At the same time, the price of WTI increased substantially in 2010 resulting in the differential widening to as much as US$31.00 per bbl during the year. The end of 2010 saw the differential narrowing to approximately US$18.51 per bbl.

Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The WTI-condensate differential is the benchmark price of condensate relative to the price of WTI. As purchased condensate is sold as part of the crude oil blend, the cost of condensate purchases impacts both our revenues and transportation and blending costs. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem.

Benchmark refining margin crack spreads for 2010 improved from 2009 due, in part, to an increase in consumer demand for refined products partly due to the improved economy in the U.S., resulting in increased gasoline and distillate consumption. However, most of the improvement can be attributed to weaker WTI prices relative to other global crude and product prices as a result of pipeline congestion in inland U.S. markets.

In 2010, benchmark NYMEX natural gas prices showed marginal improvement primarily due to increased consumption for electric power generation due to record summer heat as well as natural gas prices becoming more economical than certain coal as a fuel source for power generation. 2010 also saw natural gas demand increase for use in the industrial sector of the U.S. While NYMEX natural gas prices were higher in 2010 compared to 2009, throughout 2010 the NYMEX price has been generally on a downward trend. The main cause of the declining natural gas prices in 2010 was natural gas supply. Industry wide natural gas drilling activity, primarily from shale gas, remained strong in 2010 which resulted in higher levels of North American natural gas production as well as volumes in storage increasing to record high levels despite declining market prices.

During 2010, the Canadian dollar strengthened relative to the U.S. dollar, primarily since the economic recovery in Canada moved at a greater pace than in the U.S. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sale prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a strengthened Canadian dollar reduces this segment's reported results.

Our risk mitigation strategy has helped reduce our exposure to commodity price volatility. Realized hedging gains, after-tax, in 2010 were $199 million (2009–gains of $804 million; 2008–losses of $196 million). Further information regarding our hedging program can be found in the notes to the Consolidated Financial Statements.

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Financial Information

In our financial reporting to shareholders for the year ended December 31, 2009, we used U.S. dollars as our reporting currency and reported production on an after royalties basis. Effective January 1, 2010, we changed our reporting currency to Canadian dollars and our reporting of production to a before royalties basis. This change in reporting currency and protocol was made to better reflect our business, and allows for increased comparability to our peers. With the change in reporting currency and protocol, all comparative information has been restated from U.S. dollars to Canadian dollars and production from after royalties to before royalties.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Net Revenues	**12,973**	**13%**	11,517	-34%	17,570
Operating Cash Flow [(1)]	**2,975**	**-29%**	4,189	7%	3,933
Cash Flow [(1)]	**2,415**	**-15%**	2,845	-9%	3,115
- per share – diluted [(2)]	**3.21**		3.79		4.14
Operating Earnings [(1)]	**794**	**-48%**	1,522	-6%	1,620
- per share – diluted [(2)]	**1.06**		2.03		2.15
Net Earnings	**993**	**21%**	818	-68%	2,526
- per share – basic [(2)]	**1.32**		1.09		3.37
- per share – diluted [(2)]	**1.32**		1.09		3.36
Total Assets	**22,095**	**2%**	21,755	-4%	22,614
Total Long-Term Debt	**3,432**	**-6%**	3,656	-2%	3,719
Other Long-Term Obligations	**6,156**	**-5%**	6,507	-11%	7,308
Capital Investment	**2,122**	**-2%**	2,162	-2%	2,204
Free Cash Flow [(1)]	**293**	**-57%**	683	-25%	911
Cash Dividends [(3)]	**601**		159		n/a
- per share [(3)]	**0.80**		US$0.20		n/a

(1) Non-GAAP measure defined within this MD&A.

(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.

(3) The 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

NET REVENUES VARIANCE

($ millions)

Net Revenues for the Year Ended December 31, 2009			$ 11,517
Increase (decrease) due to:			
Upstream	Prices	$ 238	
	Realized hedging	(882)	
	Volume	(43)	
	Royalties	(176)	
	Condensate and Other [1]	299	
			(564)
Refining and Marketing			1,306
Corporate and Eliminations	Unrealized hedging	$ 728	
	Other	(14)	
			714
Net Revenues for the Year Ended December 31, 2010			**$ 12,973**

[1] Revenue dollars reported include the value of condensate sold as bitumen or heavy oil blend. Condensate costs are recorded in transportation and blending expense.

The increase in net revenues for 2010 is comprised of two main items.

Our Upstream net revenues decreased in 2010 primarily due to the decrease in our realized natural gas prices and natural gas production, as well as higher crude oil royalties. Partially offsetting these decreases were increases in the realized price and production of crude oil as well as increased prices and volumes of condensate blended with heavy oil consistent with increases in our production.

Our Refining and Marketing net revenues for 2010 increased primarily because of higher refined product prices and higher prices and volumes related to operational third party sales undertaken by the marketing group, partially offset by reduced refined products volumes from planned turnarounds, a power outage and refinery optimization activities. Also increasing net revenues in 2010, were unrealized hedging gains on natural gas.

Further information and explanations regarding our net revenues can be found in the Operating Segments and Corporate and Eliminations sections of this MD&A.

OPERATING CASH FLOW

($ millions)	**2010**	2009	2008
Crude Oil and NGLs			
Oil Sands	**$ 1,052**	$ 1,002	$ 1,019
Conventional Crude Oil and NGLs	**751**	753	1,033
Natural Gas	**1,081**	2,061	2,227
Other Upstream Operations	**16**	5	13
	2,900	3,821	4,292
Refining and Marketing	**75**	368	(359)
Operating Cash Flow	**$ 2,975**	$ 4,189	$ 3,933

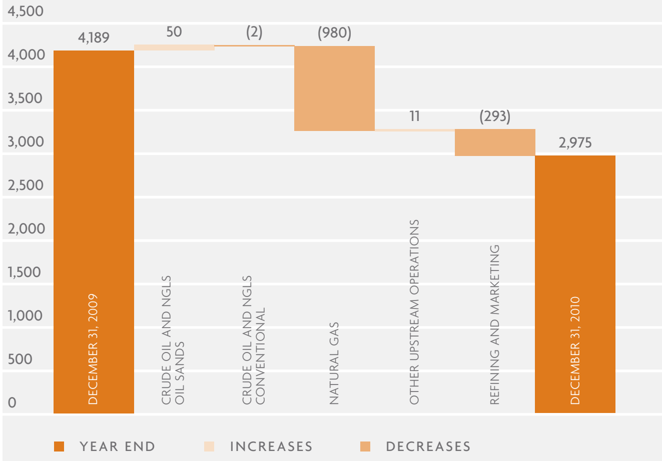
Operating cash flow is a non-GAAP measure defined as net revenues less production and mineral taxes, transportation and blending, operating and purchased product expenses. It is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow includes realized hedging gains and losses but excludes unrealized hedging gains and losses which are included in the Corporate and Eliminations segment.

Operating cash flow decreased by $1,214 million in 2010 primarily because of a $980 million reduction related to natural gas as a result of a 34 percent decrease in realized prices along with lower production volumes. Crude Oil and NGLs operating cash flow increased $48 million in 2010 as higher production and realized prices were partially offset by higher operating expenses consistent with increased production and higher royalties, mainly due to Foster Creek achieving payout status for royalty purposes in 2010.

Operating cash flow for Refining and Marketing decreased $293 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds, a power outage and refinery optimization activities related to weaker diesel and gasoline prices primarily in the first half of 2010.

Details of the components that explain the decrease in operating cash flow can be found in the Operating Segments section of this MD&A.

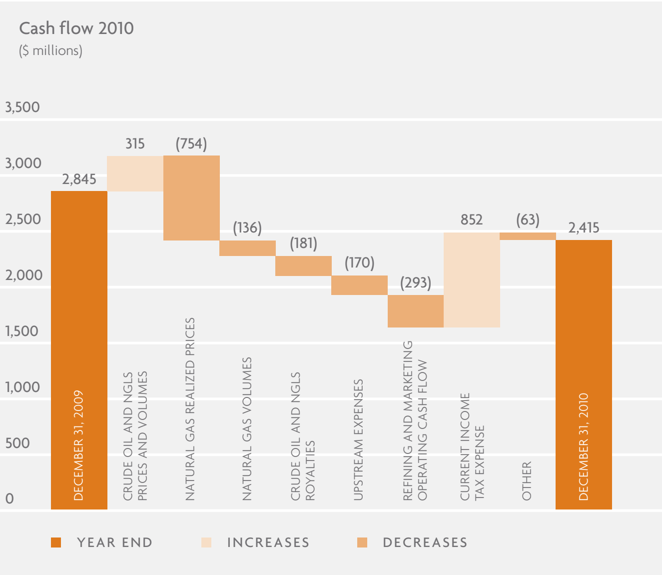
Operating cash flow 2010
($ millions)



CASH FLOW

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. Cash flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

($ millions)	**2010**	2009	2008
Cash From Operating Activities	**$ 2,594**	$ 3,039	$ 3,225
(Add back) deduct:			
Net change in other assets and liabilities	**(55)**	(26)	(92)
Net change in non-cash working capital	**234**	220	202
Cash Flow	**$ 2,415**	$ 2,845	$ 3,115



In 2010 our cash flow decreased $430 million from 2009 primarily due to:

- A 34 percent decrease in the average realized natural gas price to $5.16 per Mcf compared to $7.78 per Mcf;
- A decrease in operating cash flow from Refining and Marketing of $293 million mainly due to planned turnarounds at both refineries, higher crude costs and refinery optimization activities due primarily to weak diesel and gasoline prices in the first half of 2010. Partially offsetting these decreases to operating cash flow was a strengthening of the Canadian dollar;
- An increase in crude oil and NGLs royalties of $181 million primarily as a result of Foster Creek achieving project payout status for royalty purposes as well as higher WTI prices partially offset by a strengthened average Canadian dollar used for calculating royalties;
- Natural gas production in total declining 12 percent as a result of the divestiture of certain non-core properties, which made up four percent of the total annual decrease, as well as reduced capital expenditures;
- An increase in general and administrative and net interest expense of $75 million;
- Higher crude oil and NGLs operating expenses consistent with the increase in production; and
- Realized foreign exchange losses of $18 million in 2010 compared to gains of $23 million in 2009.

The decreases in our 2010 cash flow were partially offset by:

- A $852 million decrease in current income tax expense as a result of 2009 including acceleration of current income tax along with 2010 including the utilization of claims from tax pools that we received as a result of the Arrangement, as well as lower realized hedging gains in 2010;
- A seven percent increase in our average realized liquids price to $62.60 per bbl compared to $58.24 per bbl; and
- A six percent increase in our crude oil and NGLs production volumes.

In 2009, our cash flow decreased $270 million compared to 2008 as a result of:

- Current income tax expense increased $565 million primarily due to accelerated income tax as a result of the dissolution of a partnership as part of the Arrangement;
- A decrease in the realized average liquids selling price, including the impact of hedges, of $14.25 per bbl to $58.24 per bbl;
- Natural gas production declined 12 percent; and
- A decrease in the realized average natural gas price, including the impact of hedges, to $7.78 per Mcf compared to $7.93 per Mcf.

The 2009 cash flow decreases above were partially offset by:

- An improvement in our operating cash flow from Refining and Marketing of $727 million;
- A decrease in royalties of $260 million resulting from decreased commodity sales prices;
- An eight percent increase in our crude oil and NGLs production volumes; and
- Realized foreign exchange gains of $23 million in 2009 compared to losses of $9 million in 2008.

OPERATING EARNINGS

($ millions)		**2010**		2009		2008
Net Earnings	**$**	**993**	$	818	$	2,526
(Add back) deduct:						
Unrealized mark-to-market accounting gains (losses), after-tax (1)		**34**		(494)		636
Non-operating foreign exchange gains (losses), after-tax (2)		**153**		(210)		270
Gain on bargain purchase, after-tax		**12**		–		–
Operating Earnings	**$**	**794**	$	1,522	$	1,620

(1) The unrealized mark-to-market accounting gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.

(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax 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.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange and the effect of changes in statutory income tax rates.

We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods. The items identified above that affected our cash flow and identified below that affected our net earnings also impacted our operating earnings.

The decline in operating earnings for 2010 is consistent with the decreases to our operating cash flow and cash flow, details of which can be found above, partially offset by a decrease in depreciation, depletion and amortization ("DD&A") expense.

NET EARNINGS VARIANCE

($ millions)

Net Earnings for the Year Ended December 31, 2009		$ 818
Increase (decrease) due to:		
Operating Segments		
Upstream net revenues	$ (564)	
Upstream expenses [1]	(357)	
Upstream operating cash flow		(921)
Refining and Marketing operating cash flow		(293)
Corporate and Eliminations		
Unrealized hedging gains (losses), net of tax		528
Unrealized foreign exchange gains (losses)		396
Expenses [2]		(142)
Depreciation, depletion and amortization		217
Income taxes, excluding income taxes on unrealized hedging gains (losses)		390
Net Earnings for the Year Ended December 31, 2010		**$ 993**

[1] Includes production and mineral tax, transportation and blending and operating expenses.

[2] Includes general and administrative, net interest, accretion of asset retirement obligations, realized foreign exchange (gains) losses, gain (loss) on divestiture of assets, other (income) loss, net and Corporate operating and purchased product expenses excluding unrealized hedging.

In 2010, net earnings increased by $175 million. The items identified above that reduced our cash flow in 2010 also reduced our net earnings. Other significant factors that impacted 2010 net earnings include:

- Unrealized mark-to-market hedging gains, after-tax, of $34 million, compared to losses of $494 million, after-tax, in 2009;
- Unrealized foreign exchange gains of $69 million in 2010 compared to losses of $327 million in 2009;
- A decrease of $217 million in DD&A; and
- Future income tax expense, excluding the impact of the unrealized financial hedging gains, in 2010 of $76 million, compared to a recovery of $386 million in 2009.

In 2009, net earnings decreased $1,708 million compared to 2008. The items previously discussed that reduced our cash flow in 2009 also reduced our net earnings. Other significant factors that impacted our 2009 net earnings include:

- Unrealized mark-to-market hedging losses, after-tax, of $494 million compared to gains, after-tax of $636 million in 2008;
- DD&A expense increasing by $130 million;
- Unrealized foreign exchange losses of $327 million for 2009 compared to gains of $317 million in 2008; and
- Future income tax recovery, excluding the impact of the unrealized financial hedging gains and losses, of $386 million, compared to future income tax expense of $142 million in 2008.

HEDGING IMPACT ON NET EARNINGS

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Changes in mark-to-market gains or losses on these agreements affect our net earnings and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

($ millions)		2010		2009		2008
Unrealized Mark-to-Market Hedging Gains (Losses), after-tax [1]	$	**34**	$	(494)	$	636
Realized Hedging Gains (Losses), after-tax [2]		**199**		804		(196)
Hedging Impacts in Net Earnings	$	**233**	$	310	$	440

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

[2] Included in the Operating Segment financial results and included in operating cash flow and cash flow.

NET CAPITAL INVESTMENT

($ millions)		2010		2009		2008
Upstream						
Oil Sands	$	**867**	$	629	$	758
Conventional		**523**		466		848
		1,390		1,095		1,606
Refining and Marketing		**656**		1,033		539
Corporate		**76**		34		59
Capital Investment		**2,122**		2,162		2,204
Acquisitions		**86**		3		–
Divestitures		**(307)**		(222)		(48)
Net Capital Investment	$	**1,901**	$	1,943	$	2,156

Upstream capital investment in 2010 was primarily focused on continued development of our oil sands projects and conventional oil properties, including the drilling of stratigraphic wells to support the next phases of our expansion activities. Refining and Marketing capital investment was primarily focused on the CORE project at the Wood River refinery. Capital investment was funded by cash flow. Further information regarding our capital investment can be found in the Operating Segments section of this MD&A.

ACQUISITIONS AND DIVESTITURES

Our planned program to divest of non-core oil and gas assets in 2010 resulted in proceeds of $307 million. These divestitures included certain non-core conventional crude oil and natural gas producing properties as well as the sale of certain lands at the Narrows Lake property to the FCCL Partnership.

Our 2010 acquisitions included the purchase of an interest in three sections of undeveloped land at Narrows Lake as well as certain producing conventional oil properties. In the fourth quarter of 2010 under the terms of an agreement with an unrelated Canadian company, we acquired certain marine terminal facilities in Kitimat, British Columbia for $38 million.

FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of free cash flow, which is defined as cash flow in excess of capital investment, which excludes acquisitions and divestitures. Cash flow is a non-GAAP measure and is defined under the cash flow section of this MD&A.

($ millions)		2010		2009		2008
Cash Flow	$	**2,415**	$	2,845	$	3,115
Capital Investment		**2,122**		2,162		2,204
Free Cash Flow	$	**293**	$	683	$	911

Results of Operations

CRUDE OIL AND NGLS PRODUCTION VOLUMES

(bbls/d)	2010	2010 vs 2009	2009	2009 vs 2008	2008
Oil Sands – Heavy Oil					
Foster Creek	**51,147**	**36%**	37,725	44%	26,220
Christina Lake	**7,898**	**18%**	6,698	57%	4,279
Pelican Lake	**22,966**	**-8%**	24,870	-9%	27,324
Senlac	**–**	**–**	3,057	-5%	3,223
Conventional Liquids					
Heavy Oil	**16,659**	**-7%**	17,888	-6%	19,062
Light and Medium Oil	**29,346**	**-3%**	30,394	-3%	31,492
NGLs [1]	**1,171**	**-3%**	1,206	–%	1,203
	129,187	**6%**	121,838	8%	112,803

[1] NGLs include condensate volumes.

Overall, our crude oil and NGLs production increased six percent in 2010. Increases in production volumes at Foster Creek and Christina Lake were partially offset by expected natural declines at our other properties. We also sold certain non-core Conventional properties in 2010 which decreased our total annual crude oil production by 975 bbls/d or one percent. In 2009, we also sold our Senlac property. Further detail on the changes in our production can be found in the Operating Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf/d)	2010	2010 vs 2009	2009	2009 vs 2008	2008
Conventional	**694**	**-11%**	784	-9%	866
Oil Sands	**43**	**-19%**	53	-40%	88
	737	**-12%**	837	-12%	954

During 2009 and 2010, we chose to restrict capital spending on natural gas drilling, completion and tie-in activity in favour of increasing investment in crude oil projects. In 2010, we divested of certain non-core natural gas properties which decreased annual production by approximately 33 MMcf/d, or four percent. Weather related delays experienced throughout 2010 also negatively impacted our natural gas production.

On a barrel of oil equivalent basis, excluding the divestitures, production remained consistent in 2010 compared to 2009. Further details on the changes in our production can be found in the Operating Segments section of this MD&A.

OPERATING NETBACKS

	2010		2009		2008	
	Liquids ($/bbl)	**Natural Gas ($/Mcf)**	Liquids ($/bbl)	Natural Gas ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price [1]	**$ 62.96**	**$ 4.09**	$ 57.14	$ 4.15	$ 77.84	$ 8.17
Royalties	**9.33**	**0.07**	5.62	0.08	9.32	0.42
Production and mineral taxes	**0.62**	**0.02**	0.65	0.05	1.01	0.11
Transportation and blending [1]	**1.88**	**0.17**	1.60	0.15	1.62	0.24
Operating expenses	**11.78**	**0.96**	10.67	0.86	10.90	0.84
Netback excluding Realized Financial Hedging	**39.35**	**2.87**	38.60	3.01	54.99	6.56
Realized Financial Hedging Gains (Losses)	**(0.36)**	**1.07**	1.10	3.63	(5.35)	(0.24)
Netback including Realized Financial Hedging	**$ 38.99**	**$ 3.94**	$ 39.70	$ 6.64	$ 49.64	$ 6.32

[1] Operating netbacks for liquids exclude the value of condensate sold as bitumen blend and condensate costs recorded in transportation and blending expense.

In 2010, our average netback for liquids, excluding realized financial hedging, increased by $0.75 per bbl primarily due to an increase in prices partially offset by higher royalties and operating expenses. Our average netback for natural gas, excluding realized financial hedges, decreased by $0.14 per Mcf primarily as a result of lower sales prices and increased operating expenses per Mcf as natural gas production decreased while operating expenses were relatively consistent. Further discussions of operating results are contained in the Operating Segments section of this MD&A.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our price risk through a commodity price hedging program. Our strategy is to protect a significant portion of the subsequent years' cash flows through the use of various financial instruments. Further information regarding this program can be found in the notes to the Consolidated Financial Statements.

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Operating Segments

Our Upstream Segment has two reportable operations: Oil Sands and Conventional. Oil Sands consists of our producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, the new resource play assets such as our Narrows Lake, Grand Rapids and Telephone Lake properties as well as the Athabasca natural gas assets. Conventional includes the development and production of crude oil, natural gas and NGLs in western Canada. The Refining and Marketing segment includes our ownership interest in the Wood River and Borger Refineries and the marketing of our crude oil and natural gas, as well as third-party purchases and sales of product.

UPSTREAM

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our Pelican Lake operations. Prior to its divestiture in the fourth quarter of 2009, we also owned 100 percent of the Senlac property. We also have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Oil Sands highlights in 2010 include:

- Foster Creek achieving project payout status for royalty purposes in 2010;
- Receiving regulatory approval for the next three phases of expansion (F, G and H) at Foster Creek;
- Significant increases in production at Foster Creek and Christina Lake;
- Filing a joint application and EIA for our Narrows Lake project;
- Receiving approval for and commencing a pilot project at our Grand Rapids property; and
- Completing a large stratigraphic well program in 2010 and commencing a winter stratigraphic well program targeting to drill approximately 450 wells in 2011.

OIL SANDS – CRUDE OIL

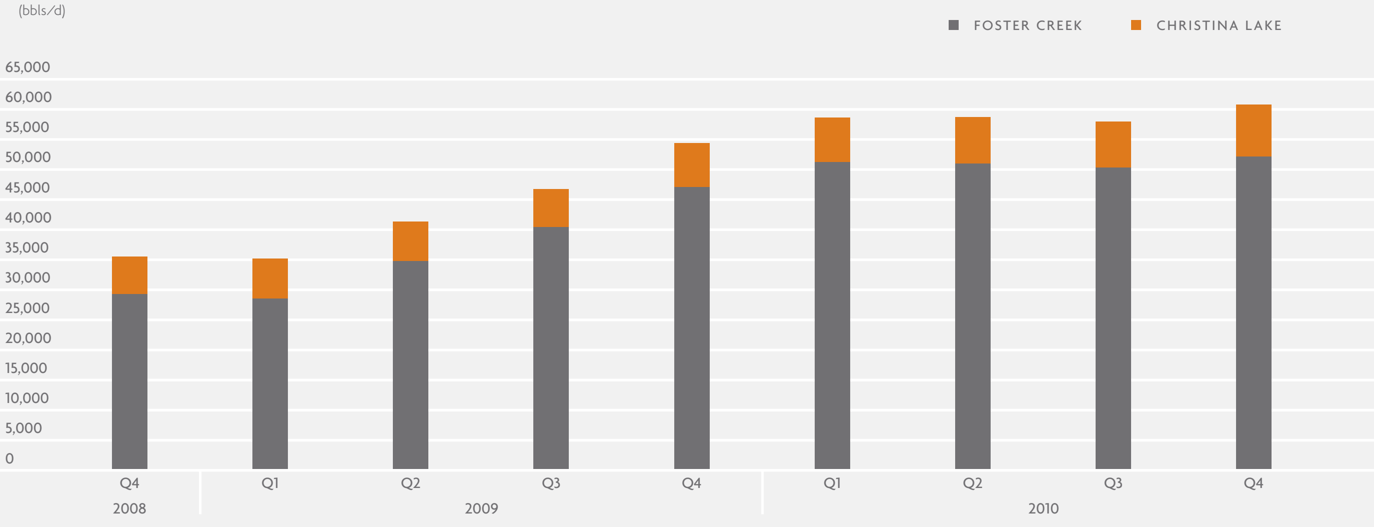
Financial Results

($ millions)		**2010**		2009		2008
Revenues	**$**	**2,611**	$	2,008	$	2,337
Deduct (add)						
Realized financial hedging (gains) losses		**8**		(48)		75
Royalties		**276**		129		178
Net revenues		**2,327**		1,927		2,084
Expenses						
Production and mineral taxes		**–**		1		2
Transportation and blending		**934**		626		784
Operating		**341**		298		279
Operating Cash Flow		**1,052**		1,002		1,019
Capital Investment		**867**		629		758
Operating Cash Flow in Excess of Related Capital	**$**	**185**	$	373	$	261

Production Volumes

Crude oil (bbls/d)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Foster Creek	**51,147**	**36%**	37,725	44%	26,220
Christina Lake	**7,898**	**18%**	6,698	57%	4,279
Total	**59,045**	**33%**	44,423	46%	30,499
Pelican Lake	**22,966**	**-8%**	24,870	-9%	27,324
Senlac	**–**	**–**	3,057	-5%	3,223
	82,011	**13%**	72,350	19%	61,046

Foster Creek and Christina Lake Production Volumes by Quarter
(bbls/d)



Net Revenues Variance

($ millions)	2009 Net Revenues	Net Revenues Variances in: Price [1]	Volume	Royalties	Condensate[2]	**2010 Net Revenues**
Crude Oil	$ 1,927	80	178	(147)	289	**$ 2,327**

[1] Includes the impact of realized financial hedging.

[2] Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In 2010 our average crude oil sales price, excluding realized financial hedges, increased eight percent to $59.76 per bbl compared to 2009 consistent with the WCS benchmark increasing year over year. Financial hedging activities for 2010 resulted in realized losses of $8 million ($0.26 per bbl) compared to gains of $48 million ($1.87 per bbl) in 2009 (2008–losses of $75 million; $3.37 per bbl).

Foster Creek production increased 36 percent primarily as a result of the phase D and E expansions, which commenced production late in the first quarter of 2009, as well as increased production from wedge wells. The 18 percent increase in production at Christina Lake was a result of increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake. At Pelican Lake, the decrease in production was the result of expected natural production declines. In the fourth quarter of 2009, we sold our Senlac heavy oil assets which had annual production of 3,057 bbls/d in 2009. Pipeline apportionments in the second half of 2010 did not significantly affect our production but did result in lower sales volumes and higher volumes in storage at the end of 2010.

Royalties increased by $147 million in 2010 compared to 2009 due to Foster Creek achieving project payout status for royalty purposes in the first quarter of 2010, along with an increased WTI price partially offset by a strengthened Canadian dollar used for calculating royalties, resulting in higher royalty rates. For 2010, the effective royalty rate for Foster Creek was 16.2 percent (2009–2.7 percent; 2008–1.1 percent) and for Christina Lake was 3.9 percent (2009–2.3 percent; 2008–1.0 percent). Pelican Lake royalties remained consistent as the increase in royalty rates due to higher prices was offset by lower volumes, which resulted in an effective royalty rate of 21.1 percent (2009–20.1 percent; 2008–20.2 percent).

Transportation and condensate blending costs increased by $308 million in 2010. The increase in condensate blending costs of $289 million was primarily related to the volume of condensate required increasing due to higher production at Foster Creek and Christina Lake as well as an increase in the average cost of condensate, while blending costs at Pelican Lake were consistent with 2009. Transportation costs increased $19 million primarily due to the higher production volumes.

Operating costs increased by $43 million due to higher repairs and maintenance, increased field personnel in relation to phased expansions, higher chemical costs and purchased fuel volumes in relation to production increases. The increase in operating costs at Foster Creek and Christina Lake is due to a 33 percent increase in production volumes. At Pelican Lake, the increase in operating costs is attributable to polymer chemical costs and increased maintenance and workover expenses.

OIL SANDS – NATURAL GAS

Oil Sands also includes our 100 percent owned natural gas operations in Athabasca. Primarily as a result of natural declines, our natural gas production decreased to 43 MMcf/d (2009–53 MMcf/d; 2008–88 MMcf/d). As a result of lower production as well as lower natural gas prices, operating cash flow declined $104 million in 2010 to $77 million (2009–$181 million; 2008–$160 million).

OIL SANDS – CAPITAL INVESTMENT

($ millions)	**2010**	2009	2008
Foster Creek	**$ 278**	$ 262	$ 356
Christina Lake	**346**	224	235
Total	**624**	486	591
Pelican Lake	**104**	72	62
New Resource Plays	**124**	17	53
Other [1]	**15**	54	52
	$ 867	$ 629	$ 758

[1] Includes Athabasca and Senlac.

Our Oil Sands capital investment in 2010 was primarily focused on the continued development of the next expansion phases of the Foster Creek and Christina Lake projects, as well as activities related to our Pelican Lake polymer flood. Our current plan is to increase gross production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the expected completion of Christina Lake phase C in 2011 and phase D in 2013.

Foster Creek capital investment in 2010 was higher as we received regulatory approval for the next phases of expansion (F, G and H). The majority of Foster Creek spending was related to drilling stratigraphic test wells, debottlenecking portions of the plant and preparation for the next phases of expansion including engineering and design, site preparation and camp construction. We are planning to accelerate the completion of Foster Creek phase F by up to 12 months which would result in production beginning in 2014.

At Christina Lake, capital investment was higher in 2010 due to construction and well pad drilling related to the phase C expansion, detailed design, procurement and construction for the phase D expansion and the drilling of stratigraphic test wells. We have chosen to accelerate completion of Christina Lake phase D by approximately six months and expect production to begin in 2013. Our current plan is to increase gross production capacity to approximately 98,000 bbls/d of bitumen with the expected completion of phase C in 2011 and phase D in 2013.

Capital investment for Pelican Lake was primarily related to capital maintenance, facility additions for polymer flooding and infill drilling opportunities.

Capital investment in new resource plays in 2010 was mainly related to the drilling of stratigraphic test wells, as shown in the following table, regulatory advancement and the Grand Rapids pilot project including the drilling of a SAGD well pair and facility construction.

Gross Stratigraphic Wells

The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion while the stratigraphic test wells drilled at Narrows Lake, Grand Rapids, Telephone Lake and other emerging projects have been drilled to assess the quality of our projects and to support regulatory applications for project approval.

	2010	2009	2008
Foster Creek	**82**	65	144
Christina Lake	**24**	28	113
Total	**106**	93	257
Narrows Lake	**39**	–	–
Grand Rapids	**71**	17	8
Telephone Lake	**26**	–	5
Other	**17**	–	5
	259	110	275

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. These conventional crude oil and natural gas assets generate reliable production and cash flows.

Conventional highlights in 2010 include:

- Generating operating cash flow in excess of capital investment of more than $1.2 billion;
- Recompleted 1,194 Alberta natural gas wells adding low cost production;
- Weyburn production increasing as a result of our well optimization program, which partially offset natural declines;
- The continued development of the Bakken and Shaunavon plays where we more than doubled average production to about 2,000 bbls/d from less than 1,000 bbls/d in 2009; and
- Divesting of certain non-core properties for proceeds of $221 million, which reduced our annual crude oil and NGLs production volume two percent and our annual natural gas production volume four percent.

CRUDE OIL AND NGLS

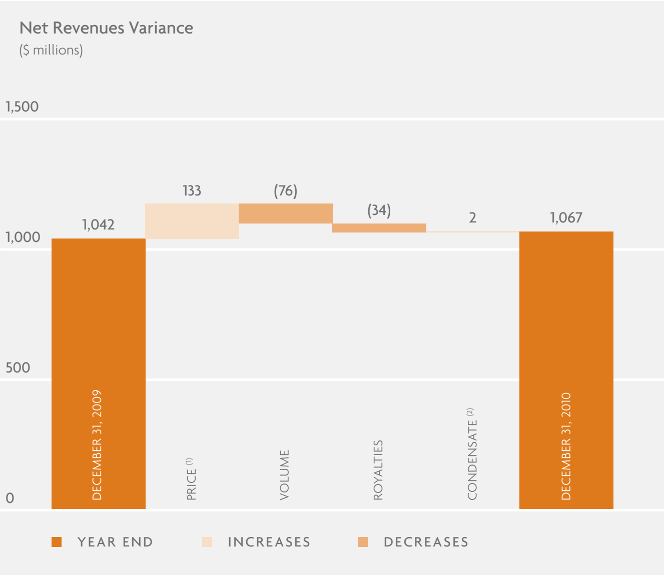
Financial Results

($ millions)	2010	2009	2008
Revenues	**$ 1,229**	$ 1,161	$ 1,752
Deduct (add)			
Realized financial hedging (gains) losses	**9**	–	146
Royalties	**153**	119	208
Net revenues	**1,067**	1,042	1,398
Expenses			
Production and mineral taxes	**28**	28	40
Transportation and blending	**86**	87	154
Operating	**202**	174	171
Operating Cash Flow	**751**	753	1,033
Capital Investment	**358**	223	359
Operating Cash Flow in Excess of Related Capital	**$ 393**	$ 530	$ 674

Production Volumes

(bbls/d)	2010	2010 vs 2009	2009	2009 vs 2008	2008
Heavy Oil					
Alberta	**16,659**	**-7%**	17,888	-6%	19,062
Light and Medium Oil					
Alberta	**10,854**	**-9%**	11,959	-14%	13,941
Saskatchewan	**18,492**	**–%**	18,435	5%	17,551
NGLs	**1,171**	**-3%**	1,206	–%	1,203
	47,176	**-5%**	49,488	-4%	51,757

Net Revenues Variance



(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

For 2010 the average crude oil and NGLs sales price, excluding realized hedging, increased 14 percent to $68.45 per bbl, consistent with the increases in benchmark prices. During 2010, realized financial hedging losses were $9 million ($0.54 per bbl) compared to gains of less than $1 million ($0.02 per bbl) in 2009 (2008–losses of $146 million; $7.67 per bbl).

Production in 2010 was lower than 2009 due to expected natural declines, the divestiture of non-core producing properties in the first half of 2010 (which had an annual average production of approximately 1,000 bbls/d), production downtime due to weather and operational challenges in Alberta and Saskatchewan. Pipeline apportionments in the second half of 2010 did not significantly affect our production but did result in lower heavy oil sales prices as well as lower sales volumes and higher volumes in storage at the end of 2010. Partially offsetting these reductions was increased production from well optimizations at Weyburn and new wells in Alberta and Saskatchewan, including increased production at Bakken and Shaunavon.

Royalties for 2010 were $34 million higher as a result of higher commodity prices, as well as higher royalty rates arising from the higher commodity prices, which resulted in an effective royalty rate of 13.3 percent for 2010 (2009–11.4 percent; 2008–13.0 percent). The higher royalty rate was partially offset by lower volumes.

Production and mineral taxes were consistent in 2010 as higher commodity prices were offset by a prior period adjustment that had increased expenses in 2009.

Transportation and blending costs were consistent in 2010 as increases in the average cost of condensate were offset by decreased volumes of condensate required for blending with heavy oil.

Operating costs increased $28 million in 2010 primarily from increased workover activity mainly at Weyburn, higher repair and maintenance activity in all areas, higher trucking costs related to new production in Saskatchewan and higher indirect costs.

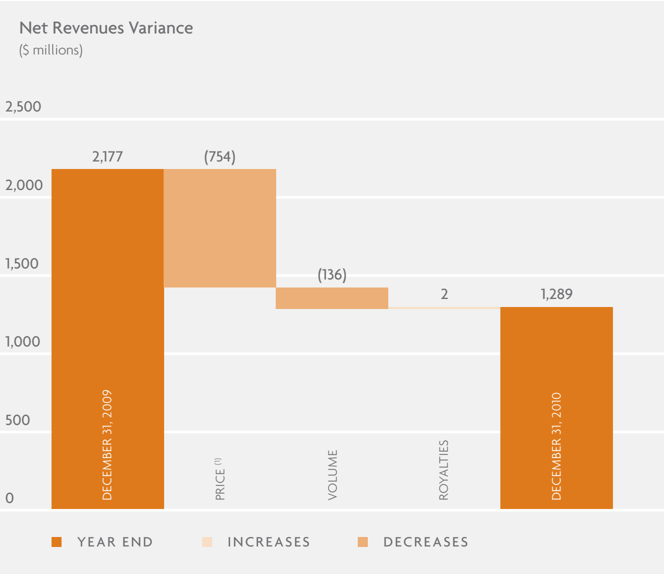
Our Conventional crude oil and NGLs operations generated $393 million of operating cash flow in excess of capital investment, a decrease of $137 million from 2009 mainly due to increased capital investment in 2010.

NATURAL GAS

Financial Results

($ millions)	**2010**	2009	2008
Revenues	**$ 1,042**	$ 1,189	$ 2,588
Deduct (add)			
Realized financial hedging (gains) losses	**(264)**	(1,007)	76
Royalties	**17**	19	79
Net revenues	**1,289**	2,177	2,433
Expenses			
Production and mineral taxes	**6**	15	38
Transportation and blending	**44**	45	76
Operating	**235**	237	252
Operating Cash Flow	**1,004**	1,880	2,067
Capital Investment	**165**	243	489
Operating Cash Flow in Excess of Related Capital	**$ 839**	$ 1,637	$ 1,578

Net Revenues Variance



(1) Includes the impact of realized financial hedging.

Our natural gas revenue and operating cash flow is down significantly due to lower realized prices. While our average natural gas price, excluding realized financial hedges, decreased slightly compared to 2009 and was consistent with the change in benchmark AECO price, the most significant decline in our revenue is a $743 million decline related to our realized financial hedging gains in 2010, which were $264 million ($1.04 per Mcf), compared to gains of $1,007 million ($3.52 per Mcf) in 2009 (2008–losses of $76 million; $0.24 per Mcf) as a result of our settled fixed price contracts being approximately $3.00 per Mcf lower than the same period in 2009 due to the oversupply of natural gas and weaker market prices. For details of the specific pricing on our hedging program, see the notes to our Consolidated Financial Statements.

The cumulative impact of restricted natural gas capital spending in 2009 and 2010 as well as divestitures of non-core properties and natural production declines reduced our natural gas production volumes by 11 percent to 694 MMcf/d in 2010 (2009–784 MMcf/d; 2008–866 MMcf/d). The divestitures reduced our 2010 annual natural gas production by approximately 33 MMcf/d.

Royalties were slightly lower in 2010 as a result of adjustments related to prior years' production partially offset by lower volumes. The average royalty rate for 2010 was 1.7 percent (2009–1.6 percent; 2008–3.1 percent).

Production and mineral taxes in 2010 were $9 million lower than 2009 mainly due to lower prices and volumes in 2010.

Costs related to transportation decreased slightly in 2010 due to lower volumes.

Operating expenses for 2010 decreased slightly as a result of reduced operations due to divestitures and lower production volumes. These declines were specifically related to lower property tax, repairs and maintenance, lower field staff and salaries as well as lower chemical costs, were offset with increased electricity prices and higher indirect costs.

Our Conventional natural gas operations generated $839 million of operating cash flow in excess of capital investment, a decrease of $798 million from 2009 mainly due to lower realized prices in 2010.

CONVENTIONAL – CAPITAL INVESTMENT

($ millions)	2010	2009	2008
Alberta	$ 303	$ 340	$ 598
Saskatchewan	220	126	250
	$ 523	$ 466	$ 848

For 2010, approximately 68 percent or $358 million of our capital investment was on our crude oil properties (2009–48 percent or $223 million; 2008–42 percent or $359 million). Capital investment in Alberta was focused on our oil program, our shallow gas projects and our liquids rich deep gas projects. Our capital investment in Saskatchewan continued to focus on drilling and facility work at Weyburn as well as appraisal projects at Lower Shaunavon and Bakken. In 2010, we drilled 36 wells in the Shaunavon and Bakken areas, 22 of which were on production at the end of 2010.

The following table details our Conventional drilling activity. Fewer natural gas wells were drilled in 2010 as our drilling program shifted towards oil wells from shallow gas wells. Well recompletions are mostly related to CBM development.

(net wells)	2010	2009	2008
Crude oil	180	105	93
Natural gas	495	502	1,375
Recompletions	1,194	855	1,017
Stratigraphic test wells	9	5	13

REFINING AND MARKETING

This operating segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. This segment's results also include the marketing group's third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Refining and Marketing highlights in 2010 include:

- The progression of the CORE project to approximately 91 percent complete from 71 percent at the beginning of the year; and
- Operating cash flow increasing in the fourth quarter by $112 million due to higher market crack spreads and increased utilization compared to the fourth quarter of 2009.

Financial Results

($ millions)	2010	2009	2008
Revenues	**$ 8,228**	$ 6,922	$ 10,684
Purchased product	**7,664**	6,020	10,500
Gross margin	**564**	902	184
Operating expenses	**489**	534	543
Operating Cash Flow	**75**	368	(359)
Capital Investment	**656**	1,033	539
Capital Investment in Excess of Operating Cash Flow	**$ (581)**	$ (665)	$ (898)

Refining and Marketing revenues in 2010 increased 19 percent primarily due to higher prices for refined products and crude oil, as well as higher marketing volumes related to operational third-party sales.

Purchased product costs, which are determined on a first-in, first-out inventory valuation basis, increased 27 percent in 2010 due mainly to higher crude costs and operational third-party marketing volumes.

Our refining operations benefitted in the fourth quarter of 2010 from the wider light-heavy crude oil price differentials that occurred in the third quarter of 2010 as a result of pipeline disruptions. In addition, the initial start up phase of the Keystone pipeline in 2010 resulted in lengthy transportation times between the purchases of a portion of our Canadian heavy oil and the processing at the refinery and resulted in the product purchased in the third quarter of 2010 to be processed in the fourth quarter of 2010.

Operating costs, consisting mainly of labour, utilities and supplies, decreased eight percent in 2010 due to lower maintenance and decreased prices for utilities consumed at the refineries and a strengthened Canadian dollar.

2010 operating cash flow decreased by $293 million mainly due to planned turnarounds at both refineries, higher average crude costs as well as refinery optimization activities due primarily to weaker diesel and gasoline prices in the first half of 2010. Partially offsetting these decreases to operating cash flow was a strengthening of the Canadian dollar.

REFINERY OPERATIONS [1]

	2010	2009	2008
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**386**	394	423
Crude utilization *(%)*	**86**	87	93
Refined products *(Mbbls/d)*	**405**	417	448

[1] Represents 100% of the Wood River and Borger refinery operations.

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 bbls/d of crude oil and 45,000 bbls/d of NGLs, including processing capability to refine up to 145,000 bbls/d of blended heavy crude oil. Upon completion of the Wood River CORE project we expect to be able to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) primarily into motor fuels.

Our crude utilization was slightly lower in 2010 primarily due to a planned turnaround at the Wood River refinery, an extended turnaround at the Borger refinery, a power outage at Wood River, unplanned maintenance and refinery optimization activities.

CAPITAL INVESTMENT

($ millions)	2010	2009	2008
Wood River Refinery	**$ 568**	$ 944	$ 477
Borger Refinery	**87**	88	45
Marketing	**1**	1	17
	$ 656	$ 1,033	$ 539

Our refining capital investment in 2010 continued to focus on the CORE project at the Wood River refinery. For 2010, of the $568 million capital expenditures at the Wood River refinery, $473 million were related to the CORE project. At December 31, 2010, the CORE project is approximately 91 percent complete. Unanticipated high water levels on the Mississippi River caused delays in the delivery schedule of various modules, which resulted in a shift to the timeline for this project. Commissioning of several of the process units has been completed with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

The balance of the Wood River and Borger refineries 2010 capital investment was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

Corporate and Eliminations

Financial Results

($ millions)		2010		2009		2008
Revenues	**$**	**(64)**	$	(778)	$	731
Expenses (add) deduct						
Operating		**3**		30		(13)
Purchased product		**(115)**		(110)		(159)
	$	**48**	$	(698)	$	903

The Corporate and Eliminations segment includes revenues that represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices. The segment also includes inter-segment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. Operating expenses primarily relate to unrealized mark-to-market gains and losses on long-term power purchase contracts.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

($ millions)		2010		2009		2008
General and administrative	**$**	**251**	$	211	$	171
Interest, net		**279**		244		233
Accretion of asset retirement obligation		**75**		45		40
Foreign exchange (gain) loss, net		**(51)**		304		(308)
(Gain) loss on divestiture of assets and other		**(4)**		(2)		3
	$	**550**	$	802	$	139

General and administrative expenses were $40 million higher in 2010 primarily due to higher salaries and benefits as we move to implement our 10 year strategic plan and complete the transition to a new independent company as well as higher long-term incentive expense due to an increase in our share price.

Net interest in 2010 was $35 million higher than 2009 primarily as a result of a full year of standby fees incurred on our committed credit facility in 2010 as well as a full year of amortization on financing costs related to the setup of debt financing programs. Additionally, interest on long-term debt was slightly higher in 2010 as a result of a higher average interest rate and higher outstanding debt in 2010 compared to the proportionate share of Encana's debt allocated to Cenovus for the majority of 2009. The weighted average interest rate on outstanding debt for the year ended December 31, 2010 was 5.8 percent (2009–5.5 percent; 2008–5.5 percent).

In 2010 we reported foreign exchange gains of $51 million (2009–losses of $304 million; 2008–gains of $308 million), the majority of which were unrealized. The strengthening of the Canadian dollar during 2010 led to unrealized gains on our U.S. dollar debt, which was partially offset by unrealized losses on our U.S. dollar partnership contribution receivable.

The 2010 gain on divestiture of assets and other includes a gain of $12 million related to the acquisition of certain marine terminal facilities in Kitimat, British Columbia in the fourth quarter of 2010.

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

The volatility of commodity prices has a significant impact on our net earnings, and as a means of managing this volatility, we enter into various financial instrument agreements. Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. 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 gains or losses reflected in corporate revenues are the result of volatility between periods in the forward commodity prices and changes in the balance of unsettled contracts. The table below provides a summary of the unrealized mark-to-market gains and losses recognized for each period. Additional information regarding financial instruments can be found in the notes to the Consolidated Financial Statements.

($ millions)		2010		2009		2008
Revenues						
Crude Oil	**$**	**(92)**	$	(102)	$	260
Natural Gas		**152**		(566)		630
		60		(668)		890
Expenses		**14**		30		(9)
		46		(698)		899
Income Tax Expense (Recovery)		**12**		(204)		263
Unrealized Mark-to-Market Gains (Losses), after-tax	**$**	**34**	$	(494)	$	636

DEPRECIATION, DEPLETION AND AMORTIZATION

($ millions)		2010		2009		2008
Upstream	**$**	**1,039**	$	1,250	$	1,179
Refining and Marketing		**239**		232		205
Corporate and Eliminations		**32**		45		13
	$	**1,310**	$	1,527	$	1,397

We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream DD&A decreased in 2010 primarily as a result of a reduced DD&A rate with the addition of proved reserves at Christina Lake phase D at the end of 2009. Refining and Marketing DD&A in 2010 includes an impairment loss of $37 million related to a processing unit determined to be a redundant asset and which would not be used in future operations at the Borger refinery. Offsetting this was lower DD&A on the refineries primarily related to a strengthening of the average U.S./Canadian dollar exchange rate in 2010. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX

($ millions)		2010		2009		2008
Current income tax expense	**$**	**82**	$	934	$	369
Future income tax expense (recovery)		**88**		(590)		405
Total Income taxes	**$**	**170**	$	344	$	774

When comparing 2010 to 2009, our current tax expense declined and our future tax expense increased. Our current income tax expense in 2009 included the acceleration of income tax incurred as a result of certain corporate restructuring transactions which were required to give effect to the Arrangement and was offset by a recovery of future income tax in 2009. Our future income tax expense in 2010 includes a tax benefit of $107 million from the recognition of net capital losses expected to be realized against future taxable capital gains. These capital losses are attributable to an internal restructuring undertaken in 2010.

Our effective tax rate for 2010 was 14.6 percent compared to 29.6 percent in 2009 (2008–23.5 percent). The decrease in 2010 is primarily due to the recognition of the future tax benefits arising from net capital losses and from operating losses in our U.S. entities in 2010 compared to earnings in 2009.

It should be noted that our 2009 income tax expense was calculated as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction, and that the calculation was based on a number of assumptions, allocations and estimates consistent with the historical carve-out consolidated financial statements.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:

- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation; and
- Taxable foreign exchange gains 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. We believe that our provision for taxes is adequate.

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Quarterly Financial Data

($ millions, except per share amounts)	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008
Net Revenues	**3,172**	**3,115**	**3,195**	**3,491**	3,005	3,001	2,818	2,693	3,946
Operating Cash Flow (1)	**812**	**660**	**665**	**838**	954	1,134	1,173	928	121
Cash Flow (1)	**648**	**509**	**537**	**721**	235	924	945	741	(209)
- per share – diluted (2)	**0.86**	**0.68**	**0.71**	**0.96**	0.31	1.23	1.26	0.99	(0.28)
Operating Earnings (1)	**140**	**159**	**142**	**353**	169	427	512	414	(159)
- per share – diluted (2)	**0.19**	**0.21**	**0.19**	**0.47**	0.23	0.57	0.68	0.55	(0.21)
Net Earnings	**73**	**223**	**172**	**525**	42	101	160	515	490
- per share – basic (2)	**0.10**	**0.30**	**0.23**	**0.70**	0.06	0.13	0.21	0.69	0.65
- per share – diluted (2)	**0.10**	**0.30**	**0.23**	**0.70**	0.06	0.13	0.21	0.69	0.65
Capital Investment	**706**	**480**	**443**	**493**	507	515	488	652	760
Free Cash Flow (1)	**(58)**	**29**	**94**	**228**	(272)	409	457	89	(969)
Cash Dividends (3)	**151**	**150**	**150**	**150**	159	n/a	n/a	n/a	n/a
- per share (3)	**0.20**	**0.20**	**0.20**	**0.20**	US$0.20	n/a	n/a	n/a	n/a

(1) Non-GAAP measure defined within this MD&A.

(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.

(3) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

In the fourth quarter of 2010 cash flow increased $413 million compared to the fourth quarter of 2009 primarily due to:

- A $526 million decrease in current income tax expense as a result of 2009 including acceleration of current income tax along with 2010 including the utilization of claims from tax pools that we received as a result of the Arrangement, as well as lower realized hedging gains in 2010; and
- A $112 million increase in operating cash flow from Refining and Marketing primarily due to higher market crack spreads and increased utilization compared to the fourth quarter of 2009.

The increases in our fourth quarter 2010 cash flow were partially offset by:

- A 22 percent decrease in the average realized natural gas price to $5.05 per Mcf from $6.44 per Mcf;
- A 14 percent decrease in natural gas production primarily due to the disposition of certain non-core properties and reduced natural gas capital expenditures;
- A five percent decrease in our average realized liquids price to $61.46 per bbl compared to $64.74 per bbl;
- A decrease in crude oil and NGLs volumes sold due to pipeline apportionments in the fourth quarter of 2010;
- Higher crude oil and NGLs operating costs consistent with the increase in production;
- An increase in general and administrative and net interest expense of $13 million; and
- An increase in royalties of $10 million primarily as a result of Foster Creek achieving royalty payout as well as higher WTI prices partially offset by a strengthened average Canadian dollar used for calculating royalties.

Our net earnings in the fourth quarter of 2010 were $31 million higher than 2009. The factors that increased our cash flow in the fourth quarter also increased net earnings. Other significant factors that impacted our fourth quarter 2010 net earnings include:

- Future income tax expense, excluding the impact of the unrealized financial hedging gains, in 2010 of $37 million, compared to a recovery of $351 million in 2009;
- Unrealized mark-to-market losses, after-tax, of $197 million, compared to losses of $92 million, after-tax, in 2009;
- Unrealized foreign exchange gains of $30 million in 2010 compared to losses of $86 million in 2009; and
- A decrease of $28 million in DD&A.

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Oil and Gas Reserves and Resources

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Prior to the year ended December 31, 2010, we presented our reserves estimates in accordance with certain U.S. disclosure requirements pursuant to an exemption from certain of the NI 51-101 requirements. Year over year comparisons are in reference to the previously disclosed December 31, 2009 estimates prepared by independent qualified reserves evaluators ("IQREs") and determined using 2009 12 month average constant prices and costs, as prescribed by the U.S. Securities and Exchange Commission ("SEC").

We retain two IQREs, McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd., to evaluate and prepare reports on 100 percent of our reserves. McDaniel also evaluated 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets with management and each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to recommend approval of the reserves and resources disclosure to the Board.

Highlights in 2010 include:

- Improved recovery factor and expansion of development area at Foster Creek led to substantial growth in our proved bitumen reserves by 288 MMbbls, a 33 percent increase from 2009;
- Conventional oil and NGLs proved reserves grew one percent; and
- An overall nine percent decline in natural gas and CBM proved reserves due to extensions and improved recoveries as well as technical revisions not enough to offset production and dispositions.

The reserves data presented summarizes our bitumen, heavy oil, light and medium oil plus NGLs, and natural gas plus CBM reserves using McDaniel's January 1, 2011 forecast prices and costs. We hold significant freehold title rights which generate production for our account from third parties leasing those lands. The before royalty volumes presented below do not include reserves associated with this production.

Information with respect to pricing as well as additional reserves information is contained in our Annual Information Form ("AIF") for the year ended December 31, 2010, available at www.sedar.com and on our website at www.cenovus.com.

RESERVES AT DECEMBER 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2010 (1)**	2009 (2)	**2010 (1)**	2009 (2)	**2010 (1)**	2009 (2)	**2010 (1)**	2009 (2)
Proved	**1,154**	866	**169**	165	**111**	112	**1,390**	1,529
Probable	**523**	479	**97**	104	**49**	53	**410**	436
Proved plus Probable	**1,677**	1,345	**266**	269	**160**	165	**1,800**	1,965

(1) Refers to 2010 estimates prepared by the IQREs using McDaniel January 1, 2011 forecast prices and costs.

(2) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.

RECONCILIATION OF PROVED RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	866	165	112	1,529
Transition to NI 51-101 Standards [2]	–	(1)	(3)	128
December 31, 2009 (NI 51-101) [3]	866	164	109	1,657
Extensions and Improved Recovery	270	9	11	45
Technical Revisions	40	15	1	60
Economic Factors	–	–	–	(18)
Dispositions	–	(5)	–	(87)
Production	(22)	(14)	(10)	(267)
December 31, 2010	1,154	169	111	1,390
Year over year change	288	4	(1)	(139)
	33%	2%	(1%)	(9%)

(1) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.

(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of royalty interest reserves from the before royalties reserves totals. See Oil and Gas Information in the Advisory section of this MD&A.

(3) Determined using McDaniel January 1, 2010 forecast prices and costs.

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	479	104	53	436
Transition to NI 51-101 Standards [2]	–	(1)	(2)	52
December 31, 2009 (NI 51-101) [3]	479	103	51	488
Extensions and Improved Recovery	132	5	(1)	12
Technical Revisions	(88)	(10)	(1)	(82)
Economic Factors	–	–	–	7
Dispositions	–	(1)	–	(15)
December 31, 2010	523	97	49	410
Year over year change	44	(7)	(4)	(26)
	9%	(7%)	(8%)	(6%)

(1) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.

(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of royalty interest reserves from the before royalties reserves totals. See Oil and Gas Information in the Advisory section of this MD&A.

(3) Determined using McDaniel January 1, 2010 forecast prices and costs.

In 2010, proved and proved plus probable bitumen reserves increased by approximately 33 and 25 percent respectively. This was primarily a result of receiving regulatory approval to expand the development area at Foster Creek and from improvements to overall recovery based on operating performance. Incremental recovery from wedge wells, drilled between existing producers, and improved recovery resulting from better than expected drainage from existing wells also contributed to the increase.

In 2010, proved heavy oil reserves increased by approximately two percent primarily as a result of expanding polymer flood areas and their successful performance at Pelican Lake. Probable heavy oil reserves decreased by approximately seven percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately one percent.

In 2010, proved light and medium oil and NGLs reserves decreased by approximately one percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and their successful performance at Weyburn being offset by current year production. Probable light and medium oil and NGLs reserves decreased by eight percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately three percent.

In 2010, proved natural gas reserves declined by approximately nine percent as extensions and technical revisions did not offset production and the divestiture of some of our natural gas assets. Probable natural gas reserves and proved plus probable reserves declined by approximately six percent and eight percent respectively.

RESOURCES AT DECEMBER 31

	Bitumen (billions of barrels)	
Before Royalties	**2010** [1]	2009 [2]
Economic contingent resources [3]		
Low Estimate	**4.4**	3.9
Best Estimate	**6.1**	5.4
High Estimate	**8.0**	7.3
Prospective resources [4]		
Low Estimate	**7.3**	7.8
Best Estimate	**12.3**	12.6
High Estimate	**21.7**	21.4

(1) Refers to estimates prepared by McDaniel, using McDaniel January 1, 2011 forecast prices and costs.

(2) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.

(3) See Oil and Gas Information in the Advisory section of this MD&A for definitions of contingent resources, economic contingent resources and low, best and high estimate. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(4) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective resources are not screened for economic viability.

Best estimate economic contingent resources increased 0.7 billion barrels or 13 percent relative to 2009. This increase is primarily as a result of significant stratigraphic well drilling converting prospective resources to contingent resources, and positive technical revisions to volumetric estimates and recovery factor estimates. Best estimate prospective resources declined 0.3 billion barrels or two percent relative to 2009, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic drilling.

The contingencies which must be overcome to enable the bitumen economic contingent resources to be classified as reserves include submission of regulatory applications with no major issues raised, access to markets, and intent to proceed by the operator and partners as evidenced by a development plan with major capital expenditures planned within five years.

Additional reserves and other oil and gas information, including the risks and uncertainties associated with reserves and resource estimates, is contained in our AIF, available at www.sedar.com and on our website at www.cenovus.com.

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Liquidity and Capital Resources

($ millions)	2010	2009	2008
Net cash from (used in)			
Operating activities	**$ 2,594**	$ 3,039	$ 3,225
Investing activities	**(1,796)**	(2,063)	(2,109)
Net cash provided (used) before Financing activities	**798**	976	1,116
Financing activities	**(631)**	(977)	(1,227)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(22)**	(32)	1
Increase (decrease) in cash and cash equivalents	**$ 145**	$ (33)	$ (110)

OPERATING ACTIVITIES

Net cash from operating activities decreased $445 million in 2010 compared to 2009 mainly because of lower cash flow. Cash flow was $2,415 million during 2010 (2009–$2,845 million; 2008–$3,115 million). Reasons for this change are discussed in the Cash Flow section of this MD&A. Cash from operating activities was also impacted by the net change in other assets and liabilities and the net change in non-cash working capital.

Excluding the impact of risk management assets and liabilities, we had working capital of $290 million at December 31, 2010 compared to working capital of $479 million at December 31, 2009. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2010 decreased to $1,796 million from $2,063 million in 2009 (2008–$2,109 million). Capital expenditures increased in 2010 to $2,208 million compared to $2,165 million in 2009 (2008–$2,204 million). Total divestiture proceeds increased in 2010 to $309 million compared to $222 million in 2009 (2008–$48 million). The changes to our capital expenditures are discussed under the Net Capital Investment and Operating Segment sections of this MD&A. Also decreasing the cash used in investing was the net change in non-cash working capital, which increased cash and cash equivalents by $99 million in 2010 compared to a $95 million decrease in 2009 (2008–increase of $96 million).

FINANCING ACTIVITIES

Cenovus has a committed credit facility and a commercial paper program that are used to manage our short term cash requirements.

In 2010, we re-negotiated our $2.5 billion credit facility by combining the two existing tranches into a single tranche and extending the maturity to November 30, 2014. At December 31, 2010, no amounts were drawn on the committed credit facility.

In 2010, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issue of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2010, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in July 2012.

In 2010, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$1.5 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2010, no notes have been issued under this U.S. shelf prospectus. The U.S. shelf prospectus expires in August 2012.

In 2010, we declared and paid quarterly dividends of $0.20 per share (2009–U.S.$0.20 per share in the fourth quarter). Dividend payments for 2010 totaled $601 million (2009–$159 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities for 2010 was $631 million (2009–$977 million; 2008–$1,227 million). The 2010 decrease in net cash used in financing was a result of net financing transactions with Encana in 2009 related to the Arrangement. In 2009, we completed a private offering of senior unsecured notes for net proceeds of $3,718 million (U.S.$3,468 million) as well as the repayment of the $3.7 billion (U.S.$3.5 billion) demand promissory note to Encana. In 2010, substantially all of these notes were exchanged for notes registered under the Securities Act of 1933 with the same terms and conditions as the original issued notes. Our debt was $3,432 million as at December 31, 2010 and does not require any payments of principal until 2014.

As at December 31, 2010, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	2010	2009	2008
Debt to Capitalization	**26%**	28%	28%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x	0.8x

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest, income taxes, DD&A, accretion of asset retirement obligations, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss). Debt is defined as the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. These metrics are used to steward our overall debt position as measures of our overall financial strength.

We target a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our capital structure can be found in the notes to the Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at December 31, 2010 there were 752.7 million (2009–751.3 million) common shares outstanding and no preferred shares outstanding.

In 2010, the Board approved a dividend reinvestment plan ("DRIP"), which permits holders of common shares to automatically reinvest all or any portion of the cash dividends paid on their common shares in additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the year ended December 31, 2010, common shares were purchased on the market to meet our DRIP requirements.

The Cenovus Employee Stock Option Plan ("ESOP") permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our common shares. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the ESOP are exercisable at 30 percent of the initial grant after one year, an additional 30 percent of the initial grant after two years and are fully exercisable after three years and expire five to seven years after the date granted. Options granted have an associated tandem share appreciation right ("TSAR"), which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our common shares over the exercise price of their option in exchange for surrendering their option. A portion of the options have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. The performance-based options that do not vest when eligible are forfeited. The exercise of an option as a TSAR for a cash payment does not result in the issuance of any additional common shares, thus having no dilutive effect.

In accordance with the Arrangement, each Cenovus and Encana employee holding Encana options prior to the Arrangement received one Cenovus replacement option and one Encana replacement option for each original Encana option held. The terms and conditions of the Cenovus replacement options are similar to the terms and conditions of the original Encana options, which are also similar to the terms and conditions of Cenovus options. The original exercise price of the Encana options was apportioned to the Cenovus and Encana replacement options based on the one-day weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the Toronto Stock Exchange on December 2, 2009.

At December 31, 2010, Cenovus employees held approximately 19.1 million options, of which 7.7 million were exercisable. At December 31, 2010, Encana employees held approximately 17.2 million Cenovus replacement options, of which 10.8 million were exercisable. No further Cenovus replacement options will be granted to Encana employees. Encana is required to reimburse Cenovus in respect of cash payments made to Encana employees for Cenovus replacement options exercised as TSARs. Cenovus is required to reimburse Encana in respect of cash payments made to Cenovus employees for Encana replacement options exercised as TSARs. No further Encana replacement options will be granted to Cenovus employees.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

	Expected Payment Date						
($ millions)	2011	2012	2013	2014	2015	2016+	Total
Long-term Debt [1]	$ –	$ –	$ –	$ 796	$ –	$ 2,685	$ 3,481
Partnership Contribution Payable [1]	343	364	386	410	435	581	2,519
Asset Retirement Obligation	100	2	2	2	2	6,012	6,120
Pipeline Transportation	107	93	167	167	166	953	1,653
Purchases of Goods and Services	157	23	12	10	7	23	232
Product Purchases	23	18	18	18	18	7	102
Operating Leases [2]	33	87	88	85	78	1,553	1,924
Capital Commitments	91	71	4	4	4	14	188
Other Long-term Commitments	4	2	1	1	–	1	9
Total Payments	$ 858	$ 660	$ 678	$ 1,493	$ 710	$ 11,829	$ 16,228
Product Sales	$ 50	$ 52	$ 54	$ 56	$ 57	$ 63	$ 332
Partnership Contribution Receivable [1]	$ 346	$ 364	$ 384	$ 405	$ 427	$ 565	$ 2,491

(1) Principal component only. See notes to the Consolidated Financial Statements.

(2) Operating leases consist of building leases.

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, future demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), building leases, capital commitments and marketing agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information please see the notes to the Consolidated Financial Statements.

As at December 31, 2010, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 73 Bcf of natural gas at a weighted average price of US$4.54 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims.

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Risk Management

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit and liquidity risk;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are 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. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

FINANCIAL RISKS

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Management monitors our operational and financial risk strategies to proactively respond to the changing economic conditions and to eliminate, mitigate or reduce the risk. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient cash resources are maintained to fund capital expenditures.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of December 31, 2010, are disclosed in the notes to the Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

COMMODITY PRICE RISK

Commodity price risk is the exposure to fluctuations in future market prices that results from the sales of various commodities in our operations.

We seek to reduce our exposure to commodity price risk through an integrated business strategy whereby a portion of operating supplies and feedstock is provided from internal operations. To further mitigate commodity price risk, we use derivative instruments in various operational markets to optimize our supply or production chain. We have partially mitigated our exposure to the crude oil commodity price risk on our crude oil sales with fixed price WTI swaps. We have partially mitigated our exposure to the natural gas commodity price risk on our natural gas sales with fixed price NYMEX and AECO swaps. We have partially mitigated our exposure to widening crude oil and natural gas price differentials with fixed price differential and basis swaps between our production areas and various sales points. We have mitigated some of our exposure to electricity consumption costs, with two derivative contracts which expire on January 1, 2018.

CREDIT RISK

Credit risk is the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms.

A substantial portion of our accounts receivable is with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policies governing our credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All financial derivative agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

LIQUIDITY RISK

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2010, no amounts were drawn on our committed credit facility. In addition, we had $1.5 billion in unused capacity under our Canadian shelf prospectus and US$1.5 billion in unused capacity under our U.S. shelf prospectus, the availability of which are dependent on market conditions.

FOREIGN EXCHANGE RISK

Foreign exchange risk is the exposure to fluctuations in foreign currency exchange rates in our operations. As our commodity sales are generally priced in U.S. dollars and our capital expenditures and expenses are paid in both U.S. and Canadian dollars, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on our financial results which are reported in Canadian dollars.

We reduce our exposure to foreign exchange risk through an integrated business strategy with a mix of U.S. and Canadian operations that creates a partial hedge to foreign exchange exposure. To further mitigate foreign exchange risk, we may enter into foreign exchange contracts or hedge our commodity exposures in Canadian dollars.

We also have the flexibility to maintain 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, we may enter into cross currency swaps on a portion of our debt as a means of managing the U.S./Canadian dollar debt mix.

INTEREST RATE RISK

Interest rate risk is the impact of changing interest rates on earnings, cash flows and valuations. Although all of our debt portfolio was fixed rate debt at December 31, 2010, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our commercial paper program and credit facilities. We may also 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 risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Our 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 our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary approvals; 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; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and, therefore, our cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, we evaluate projects on a fully risked basis, including geological risk and engineering risk. In addition, our asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes 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 Lookback and Learning results are analyzed in relation to our capital program with the results and identified learnings shared across our company.

We utilize a peer review process to ensure that capital projects are appropriately risked and that knowledge is shared across our company. Peer reviews are undertaken primarily for early stage properties, although they may occur for any type of project.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

SAFETY, ENVIRONMENTAL AND REGULATORY RISKS

We are engaged in the relatively high risk activities of crude oil and natural gas development and production and refining. We are committed to safety in our operations and with high regard for the environment and stakeholders. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, we maintain a system, in respect of our assets and operations, that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to both senior management and our Board. The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, for approval by our Board and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

We have an Investigations Committee whose mandate is to address potential violations of policies and practices and an Integrity Helpline that can be used to raise any concerns regarding operations, accounting or internal control matters.

Our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion 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 our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by our operating and corporate groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. Of note in this regard, our approach to changes in regulations relating to climate change, royalty and regulatory frameworks is discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives mentioned herein.

ENVIRONMENTAL REGULATION AND RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects. Further information regarding the status of each project can be found in the Operating Segments section of this MD&A.

CLIMATE CHANGE

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emissions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also 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 Government of Alberta has set targets for GHG emissions reductions. Regulations 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. To comply, companies can make operating improvements, purchase carbon offsets (or emission performance credits) or make a $15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus currently has three facilities subject to this regulation. For the 2010 compliance year, we do not anticipate material costs in this regard.

Our efforts with respect to emissions management are founded in our industry leadership in carbon dioxide sequestration, a focus on energy efficiency and the development of technology to reduce GHG emissions. In particular, our low steam to oil ratios at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

(1) Manage Existing Costs

When regulations are implemented, a cost is placed on our 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, attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.

(2) Respond to Price Signals

As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our 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 reduction, we are also attempting, where appropriate, to realize associated value of our reduction projects.

(3) Anticipate Future Carbon Constrained Scenarios

We continue 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, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios assist with our long range planning and our analyses on the implications of regulatory trends.

We incorporate the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on our 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 can provide direct guidance to the capital allocation process. We also examine the impact of carbon regulation on our major projects. Although uncertainty remains regarding potential future emissions regulation, our plan is to continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We recognize that there is a cost associated with carbon emissions. We believe that GHG regulations and the cost of carbon at various price levels have been adequately taken into consideration as part of our business planning and scenarios analysis. We believe that our development strategy, use of technology and focus on continuous improvement 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. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect our operations.

ALBERTA'S ROYALTY FRAMEWORK

In 2010, the Government of Alberta outlined changes to the royalty structure in the province. The updates to conventional crude oil and natural gas royalty structure released in the first quarter of 2010 included:

- A five percent maximum royalty rate on new gas and conventional oil wells for a period of 12 months or 0.5 billion cubic feet equivalent for gas wells or 50,000 barrels of oil equivalent for oil wells, whichever comes first. The five percent royalty rate was originally created with the New Well Incentive under the Energy Incentive Program that was released on March 3, 2009 and was set to expire on March 31, 2011, but is now permanently in place;
- The maximum royalty rate for conventional oil will decrease to 40 percent from 50 percent and the maximum natural gas royalty rate will decrease to 36 percent from 50 percent; and

- Effective January 1, 2011 no additional wells will be allowed under the Transitional Royalty Program ("TRP") that went into effect on January 1, 2009. The TRP allows for a one time option of selecting transitional royalty rates on new natural gas or conventional oil wells drilled between 1,000 to 3,500 metres in depth. Any wells that are elected under the TRP can continue to use this program until December 31, 2013.

Updates released in the second quarter of 2010 were primarily focused on supporting deep basin gas drilling and improving the economics of unconventional gas plays, as well as horizontal oil and gas drilling. These updates included:

- A maximum royalty rate of five percent for all products produced from horizontal oil or horizontal non-oil sands wells, with volume and production month limits set according to the depth of the well. Horizontal oil and non-oil sands wells are defined by the ERCB;
- Wells defined as horizontal natural gas wells by the ERCB will have a maximum five percent royalty rate on all production for a period of 18 producing months or 500 MMcf of gas equivalent production;
- CBM wells that produce exclusively from areas defined by the ERCB as coal will have a maximum royalty rate of five percent on all products produced in the first 36 months with a production limit of 750 MMcf of gas equivalent; and
- The Natural Gas Deep Drilling program was made permanent and was modified and simplified. Modifications include the reduction of the minimum well depth to 2,000 metres; elimination of well target, spacing and pool boundary restrictions; all lateral wells qualify for credits; increased credits between 3,500 and 5,000 metres; and removal of maximum well depth.

Also included as part of the royalty structure changes released in the second quarter were updates to the royalty curves for conventional oil and natural gas. The effective date of the new curves is January 1, 2011.

For Cenovus, the main impact of these royalty changes is expected to be a positive improvement to the economics of our oil drilling program for certain properties in our Conventional operating segment and any future shale oil developments in Alberta.

ALBERTA'S REGULATORY FRAMEWORK

As part of the Government of Alberta's competitiveness review, a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project") was initiated in March 2010. The Project's goal is to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. The Project involved engagement with a broad range of stakeholders, including industry, and led to a recommendation to the Minister of Energy for adoption of a coordinated policy framework and an integrated regulatory system for the upstream oil and gas sector. The Government of Alberta has accepted the Projects team's recommendations and is expected to begin implementing those recommendations in the first half of 2011.

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act ("ALSA"), sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licenses, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan. The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while considering social and economic impacts. In August 2010, the Lower Athabasca Regional Advisory Council ("RAC") provided its vision document to the Government of Alberta regarding the LARP. Cenovus is actively participating in the feedback process as a stakeholder with significant activities in the region and will continue to monitor developments going forward. The Government of Alberta is expected to respond to the RAC advice with its own LARP recommendations. It is possible that the RAC vision, if adopted in its current form by the Government of Alberta, may negatively impact Cenovus's access to certain resource properties or limit the pace of development due to environmental limits and thresholds.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy has been updated to ensure that it continues to drive our commitments, strategy and reporting, and also enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy was released on December 1, 2010 and is available on our website at www.cenovus.com.

In 2010, we released our "Corporate Responsibility Performance Highlights" fact sheet and launched the CR section of our website. The two-page fact sheet introduced Cenovus to our stakeholders and provided a snapshot of our 2009 CR performance. It was distributed to all of our staff, including contractors and staff in the field and to over 1,000 of our external contacts. We also created a more detailed "Corporate Responsibility 2009 Performance Measures Report" to complement the fact sheet. The Performance Measures Report organizes all 2009 CR metrics into one document and is available on our website at www.cenovus.com.

As our CR reporting process matures, indicators will be developed that better reflect Cenovus's operations and challenges. These indicators will be integrated into our CR reporting and will expand our online presence through our website.

Accounting Policies and Estimates

Management is required to make judgments, assumptions and estimates in the application of GAAP that have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to understanding our financial results.

BASIS OF PRESENTATION

Our results for the year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

Our results for the periods prior to the Arrangement, being January 1 to November 30, 2009 and January 1 to December 31, 2008, have been prepared on a "carve-out" accounting basis, whereby the results have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. The historical consolidated financial statements include allocations of certain Encana expenses, assets and liabilities. In the opinion of management, the consolidated and the historical carve-out consolidated financial statements reflect all adjustments necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with GAAP.

Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of Encana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the periods presented.

OIL AND GAS RESERVES

All of our oil and gas reserves are evaluated and reported to Cenovus by the IQREs. 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. These revisions can have a significant impact on our future earnings because they will directly impact our DD&A rates, asset impairment calculations, accounting for business combinations and asset retirement obligations.

PROPERTY, PLANT AND EQUIPMENT – DD&A

Crude oil and natural gas properties are accounted for 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, exploration for, and the development of crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, plus estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

ASSET IMPAIRMENTS

Under GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount. The recoverable amount is calculated as the total undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

We also perform an annual impairment test on goodwill, whereby the fair value of each reporting unit is determined and compared to the book value of the reporting unit. A reporting unit has all assets, including goodwill, and liabilities allocated to the country cost centre level.

For the above impairment tests, fair value is calculated as the cash flows from oil and gas properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. In order to estimate future cash flows, we are required to make a number of assumptions and estimates, including quantities of reserves, future commodity prices as well as development and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's carrying value.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. 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 carrying amount exceeds the fair value.

BUSINESS COMBINATIONS

The purchase price of business combinations and asset acquisitions is allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the use of assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation will have a direct impact on our future net earnings, largely due to the impact on the calculation of DD&A rates or asset impairment tests.

ASSET RETIREMENT OBLIGATIONS

We are required to recognize an asset retirement obligation ("ARO") liability for the future abandonment and reclamation costs associated with our property, plant and equipment. ARO is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law. Our calculation of ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal and regulatory requirements, contracts and current technologies. There are many assumptions used in the estimate of the ARO liability which can be subject to change based on experience. These assumptions include: the estimated cost of reclaiming producing well sites, crude oil and natural gas processing plants and refining facilities; inflation rates; credit-adjusted risk free rates; and the timing of retirement of assets. At the end of each year, we review our assumptions and estimates and any changes to the ARO liability are discounted to present value using a credit-adjusted risk-free discount rate.

COMPENSATION PLANS

We have obligations for payments to our employees related to our stock option and incentive plans. The obligations provide for a range of payouts based on key predetermined performance measures and the cost of these plans is expensed based on expected payouts. The amounts to be paid, if any, may vary from the current estimate.

We also have obligations for payments to our employees related to stock option plans of Encana. The financial liability for these obligations is accrued using the fair value method, and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation fluctuates, as it is based on assumptions for the risk-free discount rate, dividend yield, as well as the volatility of Encana's share price.

RISK MANAGEMENT ACTIVITIES

We use various derivative financial instruments to manage our commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. The estimated fair value of derivative financial instruments is determined using appropriate valuation models and methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, we rely primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

INCOME TAXES

We follow the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires the interpretation of changing laws and regulations, for example changing income tax rates, and making certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments have a significant impact on our provision for current and future income tax, and will have a direct impact on our future net earnings.

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations", which replaces CICA Handbook Section 1581 of the same name. The new 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. This accounting policy was applied to the November 1, 2010 purchase of the marine terminal facilities.

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements". Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest 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 early adoption of these standards did not have a material impact on the Company's Consolidated Financial Statements for the year ended December 31, 2010.

These standards are converged with International Financial Reporting Standards ("IFRS").

RECENT ACCOUNTING PRONOUNCEMENTS

There are no pending GAAP accounting pronouncements, other than the requirement to adopt IFRS in 2011, as discussed below.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

We are required to report our results in accordance with IFRS beginning with the three month period ending March 31, 2011. We have a detailed changeover plan, which includes the preparation of required comparative information for 2010. We continue to be on schedule with our plan, and expect that the adoption of IFRS will not have a significant impact or influence on our business, operations or strategies.

The information below summarizes our accounting policies and opening balance sheet information, which were disclosed in our MD&A for previous periods. It also includes additional information on the estimated IFRS impacts on our financial results for the year ended December 31, 2010.

Our IFRS financial results have not yet been finalized because:

- The results remain subject to further review by management;
- We are continuing to monitor any new or amended IFRS issued by the International Accounting Standards Board that could affect our choice of accounting policies;
- Our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011; and
- The results are unaudited and are subject to additional audit work by our external auditors.

SIGNIFICANT IMPACTS OF IFRS

The following areas are the most significantly affected by the adoption of IFRS:

- Upstream Property, Plant and Equipment ("PP&E"), including:
  - Exploration and Evaluation costs
  - Asset retirement obligation
  - Transition on date of adoption of IFRS
  - DD&A
  - Gains and losses on divestitures
- Refining Assets
- Impairment testing
- Stock-based compensation
- Income taxes

UPSTREAM PP&E

Exploration and Evaluation costs

During the exploration and evaluation ("E&E") phase, we capitalized costs incurred for these projects under GAAP. While this capitalization policy has not changed under IFRS, these costs will be reported separately as E&E assets, rather than being included in PP&E.

Asset Retirement Obligation

Under GAAP, the discount rates used to estimate the ARO liability were not updated to current market discount rates, while under IFRS, the discount rate is updated each reporting period. This difference in accounting policy did not have a significant impact on either our opening balance sheet or our net earnings for the year ended December 31, 2010. However, our ARO liability as of December 31, 2010 was higher under IFRS as a result of changes to the discount rate used to estimate the liability. The impact is expected to be less than $200 million.

Transition adjustments on date of adoption of IFRS – January 1, 2010

Under GAAP, we follow full cost accounting, while IFRS has no equivalent treatment. IFRS 1 ("First-time Adoption of IFRS") permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Using this exemption, we reclassified the cost of our unproved properties from Upstream PP&E to the new E&E asset category, and allocated the remainder of our Upstream full cost pool to our IFRS areas based on the relative fair value of each area. Fair value was calculated using the estimated future net cash flows from proved reserves, discounted at 10 percent, since this was considered to be an appropriate estimate of the relative fair value of each of our IFRS areas. This approach was also consistent with the allocation method which was required to be used in the formation of Cenovus. The allocation process did not affect the net book value of our Upstream PP&E as no IFRS impairments were recognized.

DD&A

Under GAAP, we calculated our DD&A rate at the country cost centre level. Under IFRS, this rate is calculated at a lower unit of account level, which resulted in our Upstream DD&A for the year ended December 31, 2010 increasing by less than $150 million. The increase in DD&A is primarily due to separating the long life reserves associated with the Foster Creek and Christina Lake properties from the rest of the full cost pool.

Gains and losses on divestitures

Full cost accounting under GAAP required that gains or losses on divestitures of PP&E only be recognized when the disposal would affect our DD&A rate by 20 percent or more. Under IFRS, we are required to recognize all gains and losses on upstream property divestitures. For the year ended December 31, 2010, we recognized gains on divestiture of oil and gas properties of about $125 million. Under GAAP, these gains were credited to the full cost pool, and would have resulted in a lower GAAP DD&A rate in future years compared to our IFRS DD&A rates.

REFINING ASSETS

In our IFRS opening balance sheet, we elected to re-measure the carrying value of our refineries to their fair value, which permanently reduced their carrying value by approximately $2.6 billion ($1.6 billion, after-tax). In addition, having revalued the refineries to their fair values, it was also determined that the Refining deferred asset, which had a carrying value of $121 million at January 1, 2010, was fully impaired under IFRS. The impairment loss on a refining process unit recognized under GAAP was reduced under IFRS due to the January 1, 2010 fair value election. The impact of these three IFRS adjustments was a decrease in our Refining and Marketing DD&A of less than $150 million for the year ended December 31, 2010.

IMPAIRMENT TESTING

In the first step for all of our GAAP impairment tests (Upstream, Refining and Goodwill), future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for Upstream PP&E, impairment testing was performed at the country cost centre level, while under IFRS, it is performed at the lower cash-generating unit level. There was no impact on our Upstream PP&E, Refining PP&E or goodwill with this change in accounting policy.

STOCK-BASED COMPENSATION

Under GAAP, obligations for cash payments under stock-based compensation plans were accrued using the intrinsic method, while under IFRS these obligations are accounted for using the fair value method. While the carrying value in each reporting period will be different under IFRS compared to GAAP, the cumulative expense recognized over the life of the instrument under both methods will not be different. This difference in policy did not have a significant impact on either our IFRS opening balance sheet or our net earnings for the year ended December 31, 2010.

INCOME TAXES

The carrying amounts of our tax balances have been directly impacted by the tax effects resulting from changes in our accounting policies. The future income tax liability on our IFRS opening balance sheet was reduced by approximately $1 billion, primarily due to the fair value election on our refineries. For the year ended December 31, 2010, our income tax expense increased primarily related to the tax effects on the recognition of gains on our PP&E divestitures.

SUMMARY OF IFRS IMPACTS TO DECEMBER 31, 2010

The net effect of the significant adjustments above is an increase to our net earnings mainly due to the gain on divestiture of oil and gas properties. All of the other IFRS adjustments are not significant. In total, we estimate an increase to our net earnings under IFRS for the year ended December 31, 2010 of less than $120 million.

The most significant impacts on our December 31, 2010 balance sheet are as follows:

- Decrease in PP&E of approximately $2.2 billion;
- Re-classification of approximately $0.7 billion of Upstream PP&E to E&E assets;
- Decrease in Other assets of approximately $0.1 billion;
- Increase in Asset Retirement Obligation of approximately $0.2 billion;
- Decrease in Future Income Taxes of approximately $0.9 billion; and
- Decrease in Shareholders' Equity of approximately $1.6 billion.

These balance sheet changes increased our Debt to Capitalization ratio at December 31, 2010, from 26 percent to 29 percent, which is below our target range of 30 percent to 40 percent.

In terms of our cash flow statement for the year ended December 31, 2010, the IFRS adjustments did not have a significant impact on cash from operating activities, cash used in investing activities, or cash from financing activities. Furthermore, the IFRS adjustments did not have a significant impact on cash flow, which is our non-GAAP measure defined earlier in this MD&A.

INTERNAL CONTROLS OVER FINANCIAL REPORTING & DISCLOSURE CONTROLS AND PROCEDURES

During the fourth quarter of 2010, we have updated our internal controls documentation related to external financial reporting processes, including disclosure controls and procedures. We do not expect that the adoption of IFRS will have a significant impact on any of our internal control processes.

FINANCIAL REPORTING EXPERTISE

In terms of financial literacy, we held additional internal IFRS education sessions in the fourth quarter of 2010. These education sessions will continue during 2011 across all of our finance teams to ensure that there is a strong level of knowledge of IFRS throughout the organization. We will also continue to educate our external stakeholders, primarily by disclosing and explaining the significant adjustments from GAAP to IFRS.

Outlook

Our long term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our resources in multiple phases using a low cost manufacturing-like approach;
- Leadership in low cost oil sands development enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- To primarily fund growth internally through free cash flow generation mainly from our established conventional crude oil and natural gas assets along with sufficient capacity on our debt facilities for additional cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core oil and gas assets;
- Maintaining a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and
- Maintaining a meaningful dividend.

We expect that global oil demand will continue to increase which should allow for continued strength in WTI prices. We are expecting the light-heavy differential, represented by WCS crude oil prices, to remain close to historical trends due to pipeline disruptions and Canadian heavy crude supply growing in advance of new coking capacity and pipeline access to the Gulf of Mexico. Once the new refinery and pipeline capacity is in place there should be strengthening in WCS. If the pipeline disruptions and apportionment that occurred in the second half of 2010 persist, we expect widened light-heavy oil differentials to continue in 2011, which should benefit our refining financial results. Offsetting this is a relatively weak price outlook for natural gas and refining margins although refining margins will benefit from any near term congestion in inland markets. The key challenges that need to be effectively managed to enable our growth are commodity price volatility, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our 2010 results is discussed in the Risk Management section of this MD&A and in our AIF for the year ended December 31, 2010.

We expect our 2011 capital investment program to be primarily internally funded through cash flow with sufficient capacity on our debt facilities for additional cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional crude oil and natural gas assets in Alberta and Saskatchewan are key to providing free cash flow to enable oil sands growth. Our 10 year business plan outlines how Cenovus expects to reach net oil sands production of 300,000 bbls/d by the end of 2019. We are planning continued expansions at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve this objective.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have historically benefitted from this strategy, there is no certainty that we will continue to derive such benefits in the future.

We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

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Advisory

FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this MD&A is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", or "F", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, forecasted commodity prices, future use and development of technology and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining a desirable debt to cash flow ratio; our ability to access external sources of debt and equity capital; success of hedging strategies; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form/Form 40-F for the year ended December 31, 2010, available at www.sedar.com, www.sec.gov and www.cenovus.com.

OIL AND GAS INFORMATION

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2010 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. The estimates were based on the Canadian Oil and Gas Evaluation Handbook and comply with the requirements of National Instrument 51-101.

- Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development.

- Economic Contingent Resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2010 reserves evaluation, which comply with NI 51-101 requirements.
- Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.
- Best Estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent confidence level that the actual quantities recovered will equal or exceed the estimate.
- Low Estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty – a 90 percent confidence level – that the actual quantities recovered will equal or exceed the estimate.
- High Estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty – a 10 percent confidence level – that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated on a project level. The high and low estimates are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. The aggregated low estimate results shown may have a higher level of confidence than the individual projects, and the aggregated high estimate results shown may have a lower level of confidence than the individual projects.

Additional information relating to our oil and gas reserves and resources is presented in our AIF for the year ended December 31, 2010, available at www.sedar.com and on our website at www.cenovus.com.

CRUDE OIL, NGLS AND NATURAL GAS CONVERSIONS

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one bbl. BOE 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 represent value equivalency at the wellhead.

ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

OIL AND NATURAL GAS LIQUIDS

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	Natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
WTI	West Texas Intermediate
WCS	Western Canada Select

NATURAL GAS

Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	Gigajoule
CBM	Coal Bed Methane

The Arrangement refers to the commencement of independent operations on December 1, 2009 following an agreement with Encana creating two independent publicly traded energy companies.

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by GAAP such as cash flow, operating cash flow, free cash flow, operating earnings, adjusted EBITDA, debt and capitalization and therefore are considered non-GAAP measures. 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 our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. The definition and reconciliation of each non-GAAP measure, is presented in this MD&A.

ADDITIONAL INFORMATION

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

Additional information relating to Cenovus Energy Inc., including our AIF for the year ended December 31, 2010, is available on SEDAR at www.sedar.com and on our website at www.cenovus.com.

Report of Management

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. ("Cenovus") are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of three independent directors. The Audit Committee 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 with Management and the independent auditors at least on a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to 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 internal control over financial reporting as at December 31, 2010. 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 design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2010 as stated in their Auditors' Report. PricewaterhouseCoopers LLP has provided such opinions.

Brian C. Ferguson
President & Chief Executive Officer
Cenovus Energy Inc.

Ivor M. Ruste
Executive Vice-President & Chief Financial Officer
Cenovus Energy Inc.

February 18, 2011

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Independent Auditor's Report

TO THE SHAREHOLDERS OF CENOVUS ENERGY INC.

We have completed integrated audits of Cenovus Energy Inc.'s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Cenovus Energy Inc., which comprise the consolidated balance sheets at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings and comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits 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 whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Cenovus Energy Inc. as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the three years in the period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2010, based on criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

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 Controls over Financial Reporting.

AUDITOR'S RESPONSIBILITY

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 on the company's internal control over financial reporting.

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

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 Canadian 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 Canadian 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.

INHERENT LIMITATIONS

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.

OPINION

In our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control — Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 18, 2011

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, ($ millions, except per share amounts)		2010	2009	2008
Gross Revenues	(Note 1)	**13,422**	11,790	18,103
Less: Royalties	(Note 1)	**449**	273	533
Net Revenues		**12,973**	11,517	17,570
Expenses	(Note 1)			
Production and mineral taxes		**34**	44	80
Transportation and blending		**1,065**	760	1,021
Operating		**1,302**	1,312	1,292
Purchased product		**7,549**	5,910	10,341
Depreciation, depletion and amortization		**1,310**	1,527	1,397
General and administrative		**251**	211	171
Interest, net	(Note 8)	**279**	244	233
Accretion of asset retirement obligation	(Note 16)	**75**	45	40
Foreign exchange (gain) loss, net	(Note 9)	**(51)**	304	(308)
(Gain) loss on divestiture of assets		**9**	–	–
Other (income) loss, net	(Note 6)	**(13)**	(2)	3
		11,810	10,355	14,270
Earnings Before Income Tax		**1,163**	1,162	3,300
Income tax expense	(Note 10)	**170**	344	774
Net Earnings		**993**	818	2,526
Other Comprehensive Income (Loss), Net of Tax				
Foreign currency translation adjustment		**(13)**	(238)	347
Comprehensive Income		**980**	580	2,873
Net Earnings per Common Share	(Note 22)			
Basic		**1.32**	1.09	3.37
Diluted		**1.32**	1.09	3.36

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31, ($ millions)		**2010**	2009
Assets			
Current Assets			
Cash and cash equivalents		**300**	155
Accounts receivable and accrued revenues		**1,055**	978
Income tax receivable		**31**	40
Current portion of Partnership Contribution Receivable	(Note 11)	**346**	345
Risk management	(Note 21)	**163**	60
Inventories	(Note 12)	**880**	875
		2,775	2,453
Assets Held for Sale	(Note 6)	**65**	–
Property, Plant and Equipment, net	(Notes 1, 13)	**15,530**	15,214
Partnership Contribution Receivable	(Note 11)	**2,145**	2,621
Risk Management	(Note 21)	**43**	1
Other Assets	(Note 14)	**391**	320
Goodwill	(Note 1)	**1,146**	1,146
		22,095	21,755
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**1,825**	1,574
Income tax payable		**154**	–
Current portion of Partnership Contribution Payable	(Note 11)	**343**	340
Risk management	(Note 21)	**163**	70
		2,485	1,984
Liabilities Related to Assets Held for Sale	(Note 6)	**7**	–
Long-Term Debt	(Note 15)	**3,432**	3,656
Partnership Contribution Payable	(Note 11)	**2,176**	2,650
Risk Management	(Note 21)	**10**	4
Asset Retirement Obligation	(Note 16)	**1,213**	1,147
Other Liabilities	(Note 17)	**346**	239
Future Income Taxes	(Note 10)	**2,404**	2,467
		12,073	12,147
Commitments and Contingencies	(Note 23)		
Shareholders' Equity	(Note 18)	**10,022**	9,608
		22,095	21,755

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board

Michael A. Grandin

Director

Cenovus Energy Inc.

Colin Taylor

Director

Cenovus Energy Inc.

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)	Share Capital (Note 18)	Paid in Surplus (Note 18)	Retained Earnings	AOCI*	Owner's Net Investment (Note 18)	Total
Balance as at December 31, 2007	–	–	–	(123)	8,035	7,912
Net earnings	–	–	–	–	2,526	2,526
Net distribution to owner	–	–	–	–	(1,297)	(1,297)
Other comprehensive income (loss)	–	–	–	347	–	347
Balance as at December 31, 2008	–	–	–	224	9,264	9,488
Net earnings	–	–	–	–	773	773
Net distribution to owner	–	–	–	–	(302)	(302)
Other comprehensive income (loss)	–	–	–	(212)	–	(212)
Owner's Net Investment at Arrangement date – November 30, 2009	–	–	–	12	9,735	9,747
Issuance of common stock in connection with the Arrangement	3,680	–	–	–	(3,680)	–
Reclassification of owner's net investment to paid in surplus in connection with the Arrangement	–	6,055	–	–	(6,055)	–
Net earnings – December 1 to December 31	–	–	45	–	–	45
Dividends on common shares	–	(159)	–	–	–	(159)
Common shares issued under option plans	1	–	–	–	–	1
Other comprehensive income (loss)	–	–	–	(26)	–	(26)
Balance as at December 31, 2009	3,681	5,896	45	(14)	–	9,608
Net earnings	–	–	993	–	–	993
Common shares issued under option plans	35	–	–	–	–	35
Dividends on common shares	–	–	(601)	–	–	(601)
Other comprehensive income (loss)	–	–	–	(13)	–	(13)
Balance as at December 31, 2010	**3,716**	**5,896**	**437**	**(27)**	**–**	**10,022**

* Accumulated Other Comprehensive Income

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, ($ millions)		2010	2009	2008
Operating Activities				
Net earnings		**993**	818	2,526
Depreciation, depletion and amortization		**1,310**	1,527	1,397
Future income taxes (recovery)	(Note 10)	**88**	(590)	405
Unrealized (gain) loss on risk management	(Note 21)	**(46)**	698	(899)
Unrealized foreign exchange (gain) loss	(Note 9)	**(69)**	327	(317)
Accretion of asset retirement obligation	(Note 16)	**75**	45	40
(Gain) loss on divestiture of assets		**9**	–	–
Other		**55**	20	(37)
Net change in other assets and liabilities		**(55)**	(26)	(92)
Net change in non-cash working capital		**234**	220	202
Cash From Operating Activities		**2,594**	3,039	3,225
Investing Activities				
Capital expenditures	(Note 1)	**(2,208)**	(2,165)	(2,204)
Proceeds from divestitures	(Note 7)	**309**	222	48
Net change in other assets		**4**	(25)	(49)
Net change in non-cash working capital		**99**	(95)	96
Cash (Used in) Investing Activities		**(1,796)**	(2,063)	(2,109)
Net Cash Provided before Financing Activities		**798**	976	1,116
Financing Activities				
Net issuance (repayment) of revolving long-term debt		**(58)**	(342)	41
Issuance of long-term debt		**–**	204	276
Repayment of long-term debt		**–**	(97)	(247)
Issuance of U.S. Unsecured Notes	(Note 15)	**–**	3,718	–
Payment of note payable to Encana	(Note 15)	**–**	(3,701)	–
Payment of transition account payable to Encana		**–**	(264)	–
Net financing transactions with Encana		**–**	(302)	(1,297)
Issuance of common shares		**28**	1	–
Dividends on common shares		**(601)**	(159)	–
Other		**–**	(35)	–
Cash (Used in) Financing Activities		**(631)**	(977)	(1,227)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(22)**	(32)	1
Increase (Decrease) in Cash and Cash Equivalents		**145**	(33)	(110)
Cash and Cash Equivalents, Beginning of Year		**155**	188	298
Cash and Cash Equivalents, End of Year		**300**	155	188
Supplemental Cash Flow Information	(Note 22)			

See accompanying Notes to Consolidated Financial Statements.

All amounts in $ millions, unless otherwise indicated.
For the year ended December 31, 2010

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. ("Cenovus" or the "Company") is in the business of the development, production and marketing of crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States ("U.S.").

The Company is headquartered in Calgary, Alberta and its Common Shares are listed on the Toronto and New York stock exchanges. Information on the Company's background and the basis of presentation for these financial statements are found in Note 2.

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

- **Upstream,** which includes Cenovus's development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
  - **Oil Sands,** which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company and operated by Cenovus.
  - **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.
- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations,** which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location. Capital expenditures, goodwill, sales information and information relating to Cenovus's major customers are summarized at the end of the note.

RESULTS OF OPERATIONS – SEGMENT AND OPERATIONAL INFORMATION

	Oil Sands			Conventional			Total Upstream		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,719**	2,277	2,558	**2,539**	3,369	4,130	**5,258**	5,646	6,688
Less: Royalties	**279**	135	246	**170**	138	287	**449**	273	533
Net Revenues	**2,440**	2,142	2,312	**2,369**	3,231	3,843	**4,809**	5,373	6,155
Expenses									
Production and mineral taxes	**–**	1	2	**34**	43	78	**34**	44	80
Transportation and blending	**935**	628	791	**130**	132	230	**1,065**	760	1,021
Operating	**369**	332	335	**441**	416	427	**810**	748	762
Purchased product	**–**	–	–	**–**	–	–	**–**	–	–
	1,136	1,181	1,184	**1,764**	2,640	3,108	**2,900**	3,821	4,292
Depreciation, depletion and amortization							**1,039**	1,250	1,179
Segment Income (Loss)							**1,861**	2,571	3,113
Balances as at December 31,									
Property, Plant & Equipment							**10,196**	10,095	9,949
Goodwill							**1,146**	1,146	1,146
Total Assets							**14,543**	14,921	15,466

	Refining and Marketing			Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**8,228**	6,922	10,684	**(64)**	(778)	731	**13,422**	11,790	18,103
Less: Royalties	**–**	–	–	**–**	–	–	**449**	273	533
Net Revenues	**8,228**	6,922	10,684	**(64)**	(778)	731	**12,973**	11,517	17,570
Expenses									
Production and mineral taxes	**–**	–	–	**–**	–	–	**34**	44	80
Transportation and blending	**–**	–	–	**–**	–	–	**1,065**	760	1,021
Operating	**489**	534	543	**3**	30	(13)	**1,302**	1,312	1,292
Purchased product	**7,664**	6,020	10,500	**(115)**	(110)	(159)	**7,549**	5,910	10,341
	75	368	(359)	**48**	(698)	903	**3,023**	3,491	4,836
Depreciation, depletion and amortization	**239**	232	205	**32**	45	13	**1,310**	1,527	1,397
Segment Income (Loss)	**(164)**	136	(564)	**16**	(743)	890	**1,713**	1,964	3,439
General and Administrative				**251**	211	171	**251**	211	171
Interest, net				**279**	244	233	**279**	244	233
Accretion of asset retirement obligation				**75**	45	40	**75**	45	40
Foreign exchange (gain) loss, net				**(51)**	304	(308)	**(51)**	304	(308)
(Gain) loss on divestiture of assets				**9**	–	–	**9**	–	–
Other (income) loss, net				**(13)**	(2)	3	**(13)**	(2)	3
				550	802	139	**550**	802	139
Earnings Before Income Tax							**1,163**	1,162	3,300
Income tax expense							**170**	344	774
Net Earnings							**993**	818	2,526
Balances as at December 31,									
Property, Plant & Equipment	**5,188**	5,003	4,967	**146**	116	98	**15,530**	15,214	15,014
Goodwill	**–**	–	–	**–**	–	–	**1,146**	1,146	1,146
Total Assets	**6,714**	6,404	5,964	**838**	430	1,184	**22,095**	21,755	22,614

UPSTREAM PRODUCT AND OPERATIONAL INFORMATION

	Crude Oil & NGLs								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,603**	2,056	2,262	**1,220**	1,161	1,606	**3,823**	3,217	3,868
Less: Royalties	**276**	129	178	**153**	119	208	**429**	248	386
Net Revenues	**2,327**	1,927	2,084	**1,067**	1,042	1,398	**3,394**	2,969	3,482
Expenses									
Production and mineral taxes	**–**	1	2	**28**	28	40	**28**	29	42
Transportation and blending	**934**	626	784	**86**	87	154	**1,020**	713	938
Operating	**341**	298	279	**202**	174	171	**543**	472	450
Operating Cash Flow	**1,052**	1,002	1,019	**751**	753	1,033	**1,803**	1,755	2,052

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**102**	214	278	**1,306**	2,196	2,512	**1,408**	2,410	2,790
Less: Royalties	**1**	6	68	**17**	19	79	**18**	25	147
Net Revenues	**101**	208	210	**1,289**	2,177	2,433	**1,390**	2,385	2,643
Expenses									
Production and mineral taxes	**–**	–	–	**6**	15	38	**6**	15	38
Transportation and blending	**1**	2	7	**44**	45	76	**45**	47	83
Operating	**23**	25	43	**235**	237	252	**258**	262	295
Operating Cash Flow	**77**	181	160	**1,004**	1,880	2,067	**1,081**	2,061	2,227

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**14**	7	18	**13**	12	12	**27**	19	30
Less: Royalties	**2**	–	–	**–**	–	–	**2**	–	–
Net Revenues	**12**	7	18	**13**	12	12	**25**	19	30
Expenses									
Production and mineral taxes	**–**	–	–	**–**	–	–	**–**	–	–
Transportation and blending	**–**	–	–	**–**	–	–	**–**	–	–
Operating	**5**	9	13	**4**	5	4	**9**	14	17
Operating Cash Flow	**7**	(2)	5	**9**	7	8	**16**	5	13

	Total								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,719**	2,277	2,558	**2,539**	3,369	4,130	**5,258**	5,646	6,688
Less: Royalties	**279**	135	246	**170**	138	287	**449**	273	533
Net Revenues	**2,440**	2,142	2,312	**2,369**	3,231	3,843	**4,809**	5,373	6,155
Expenses									
Production and mineral taxes	**–**	1	2	**34**	43	78	**34**	44	80
Transportation and blending	**935**	628	791	**130**	132	230	**1,065**	760	1,021
Operating	**369**	332	335	**441**	416	427	**810**	748	762
Operating Cash Flow	**1,136**	1,181	1,184	**1,764**	2,640	3,108	**2,900**	3,821	4,292

GEOGRAPHIC INFORMATION

The Refining and Marketing segment operates in both Canada and the United States. Both of Cenovus's refining facilities are located and carry on business in the United States. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third party purchases and sales of product is undertaken in Canada. Physical product sales that settle in the United States are considered to be export sales undertaken by a Canadian business.

	Refining and Marketing								
	Canada (Marketing)			United States (Refining)			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**1,604**	965	1,211	**6,624**	5,957	9,473	**8,228**	6,922	10,684
Less: Royalties	**–**	–	–	**–**	–	–	**–**	–	–
Net Revenues	**1,604**	965	1,211	**6,624**	5,957	9,473	**8,228**	6,922	10,684
Expenses									
Operating	**17**	17	20	**472**	517	523	**489**	534	543
Purchased product	**1,579**	938	1,184	**6,085**	5,082	9,316	**7,664**	6,020	10,500
Operating Cash Flow	**8**	10	7	**67**	358	(366)	**75**	368	(359)
Depreciation, depletion and amortization	**10**	12	4	**229**	220	201	**239**	232	205
Segment Income (Loss)	**(2)**	(2)	3	**(162)**	138	(567)	**(164)**	136	(564)

CAPITAL EXPENDITURES

For the years ended December 31,	**2010**	2009	2008
Capital			
Oil Sands	**867**	629	758
Conventional	**523**	466	848
Upstream	**1,390**	1,095	1,606
Refining and Marketing	**656**	1,033	539
Corporate	**76**	34	59
	2,122	2,162	2,204
Acquisition Capital			
Oil Sands	**25**	–	–
Conventional	**23**	3	–
Refining and Marketing	**38**	–	–
Total	**2,208**	2,165	2,204

In addition to the above, in 2009 Cenovus acquired strategic bitumen lands in exchange for certain non-core holdings.

GOODWILL ADDITIONS

There were no additions to goodwill during 2010, 2009 or 2008.

EXPORT SALES

Sales of crude oil, natural gas and NGLs produced or purchased in Canada delivered to customers outside of Canada were $646 million (2009–$618 million; 2008–$1,388 million).

MAJOR CUSTOMERS

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2010, Cenovus had two customers (2009–two; 2008–two) which individually accounted for more than 10 percent of its consolidated gross revenues. Sales to these customers, major international integrated energy companies with an investment grade credit rating, were approximately $7,671 million (2009–$6,389 million; 2008–$9,619 million).

2. BACKGROUND & BASIS OF PRESENTATION

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. The Company's functional currency is Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held. Common shares of Cenovus began trading on a "when issued" basis on the Toronto ("TSX") and New York ("NYSE") stock exchanges on November 2, 2009. Regular trading of the Cenovus shares began on the TSX on December 3, 2009 and on the NYSE on December 9, 2009.

Up until the completion of the Arrangement, Encana was considered a related party due to its parent-subsidiary relationship with the Cenovus entities. However, subsequent to the Arrangement, Encana is no longer a related party as defined by the CICA Handbook Section 3840 – Related Party Transactions.

BASIS OF PRESENTATION/CARVE-OUT FINANCIAL INFORMATION

The results for the year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent the Company's operations, cash flow and financial position as a stand-alone entity. The results for the periods prior to the Arrangement, being from January 1 to November 30, 2009 and January 1 to December 31, 2008 have been prepared on a "carve-out" accounting basis whereby the results have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus.

As the Company operated as part of Encana and was not a stand-alone entity prior to November 30, 2009, the historical Consolidated Financial Statements include allocations of certain Encana revenues, expenses, assets and liabilities, including the items described below.

The operating results of Cenovus were specifically identified based on Encana's divisional organization. Certain other expenses presented in the Consolidated Statements of Earnings and Comprehensive Income represent allocations and estimates of the cost of services incurred by Encana. These allocations and estimates include unrealized mark-to-market gains and losses, general and administrative costs, net interest, foreign exchange gains and losses and income tax expenses. The majority of the assets and liabilities of Cenovus were identified based on the divisional structure, with the most significant exceptions being property, plant and equipment ("PP&E"), income taxes payable and long-term debt.

Refining, crude oil and natural gas marketing and corporate depreciation, depletion and amortization were specifically identified based on Encana's divisional structure where possible. Depletion related to upstream properties was allocated to Cenovus based on the related production volumes utilizing the depletion rate calculated for Encana's consolidated Canadian cost centre.

Mark-to-market gains and losses resulting from derivative financial instruments entered into by Encana were allocated to Cenovus based on the related product volumes.

Salaries, benefits, pension, long-term incentives and other post-employment benefits costs, assets and liabilities were allocated to Cenovus based on Management's best estimate of how services were historically provided by existing employees. Costs, assets and liabilities associated with retired employees remained with Encana.

Net interest expense was calculated primarily using the debt balance allocated to Cenovus.

Income taxes were recorded as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction.

The calculation of income taxes is based on a number of assumptions, allocations and estimates, including those used to prepare the Cenovus Carve-out Consolidated Financial Statements. Prior to the Arrangement, Cenovus's tax pools were allocated for the Canadian cost centre based on the same allocation method used to determine PP&E for carve-out purposes.

PP&E related to upstream oil and gas activities are accounted for by Cenovus using the full cost method of accounting. PP&E related to upstream oil and gas activities was determined based on an allocation process which used the ratio of future net revenue, discounted at 10 percent, of the respective divisions of Encana to the future net revenue, discounted at 10 percent, of all proved properties in Canada at December 31, 2008. Future net revenue was the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves.

Goodwill was allocated to Cenovus based on the properties associated with the former business combinations on which it arose.

For the purpose of preparing the Carve-out Consolidated Financial Statements, it was determined that Cenovus should maintain approximately the same Debt to Capitalization ratio as consolidated Encana based on U.S. dollar amounts. As a result, prior to the Arrangement, debt was allocated to Cenovus based on this ratio, which was calculated using U.S. dollars. Debt is defined as the current and long-term portions of Long-term Debt. Capitalization is not a term that has a prescribed meaning under generally accepted accounting principles ("non-GAAP") and is a measure defined as Debt plus Shareholders' Equity.

Management believes the assumptions underlying the Cenovus Carve-out Consolidated Financial Statements are reasonable. However, the Cenovus Consolidated Financial Statements herein may not reflect Cenovus's financial position, results of operations, and cash flows had Cenovus been a stand-alone company during the periods presented or what Cenovus's operations, financial position, and cash flows will be in the future. Encana's direct investment in

Cenovus is shown as Net Investment in place of Shareholders' Equity because a direct ownership by shareholders in Cenovus did not exist prior to November 30, 2009. Encana's investment includes the accumulated net earnings, other comprehensive income and net cash distributions to Encana.

In the opinion of Management, the Consolidated and the historical Carve-out Consolidated Financial Statements reflect all adjustments (including normal recurring adjustments) necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

3. CHANGE IN REPORTING CURRENCY

As a result of the Arrangement, Cenovus reported its results in U.S. dollars for the preparation of its December 31, 2009 consolidated financial statements as this was the reporting currency used by Encana. Effective January 1, 2010, the Company changed its reporting currency to Canadian dollars. The change in reporting currency is to better reflect the business of Cenovus, and it allows for increased comparability to the Company's peers. In implementing this change, the Company has followed the requirements of the Canadian Institute of Chartered Accountants ("CICA") Emerging Issues Committee ("EIC") Abstract 130 ("EIC-130"), "Translation Method When the Reporting Currency Differs from the Measurement Currency or there is a Change in the Reporting Currency."

With the change in reporting currency, all comparative financial information has been restated from U.S. dollars to Canadian dollars to reflect the Company's consolidated financial statements as if they had been historically reported in Canadian dollars.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries and are presented in accordance with Canadian GAAP. Information prepared in accordance with GAAP in the United States is included in Note 24.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on certain of Cenovus's development, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby Cenovus'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.

Monetary assets and liabilities of Cenovus 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 crude oil and natural gas reserves, future costs required to develop those reserves and future cash flows. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

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

The amount of compensation expense accrued for long-term performance-based compensation arrangements 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 estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As such, income taxes are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when title passes from the Company to its customer. Realized gains and losses from crude oil and natural gas commodity price risk management activities are recorded in revenue when the product is sold.

Revenues and purchased product are recorded on a gross basis when the title to product passes and the risks and rewards of ownership have been transferred. 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 as agent are recorded as the services are provided.

Unrealized gains and losses from 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 to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is produced.

F) Transportation and Blending Costs

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

Accruals for obligations under the employee benefit plans and the related costs are recorded 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 calculated 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

Cenovus follows the liability method of accounting for income taxes, where 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 share amounts are calculated giving effect to the potential dilution that would occur if stock options, without tandem stock appreciation rights attached, were exercised or other contracts expected to result in the issuance of 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 stock 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, including petroleum and refined products, 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

Crude oil and natural gas properties are accounted for in accordance with the 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 bitumen, crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, natural gas is converted to oil 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 depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from 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 depreciation, depletion and amortization.

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

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

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

Refining

The initial acquisition costs of refining 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 the estimated service lives of each component of the refining facilities.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. 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 carrying amount exceeds the fair value.

Other

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.

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.

N) Amortization of Other Assets

Items included in 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. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as a reporting unit. To assess impairment, the fair value of the 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 Sheets when incurred and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where Cenovus will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing plants, and refining facilities. 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 Statements 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 Statements of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) Stock-Based Compensation

Obligations for payments, cash or common shares, under Cenovus's stock option, performance share unit and deferred share unit plans are accrued using the intrinsic method as compensation cost over the vesting period. Fluctuations in the price of Cenovus's common shares change the accrued compensation cost and are recognized when they occur.

Encana replacement stock options with tandem stock appreciation rights attached held by Cenovus employees are accrued using the fair value method. The fair value is recognized as compensation cost over the vesting period. Fluctuations in the fair value of the rights 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. 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".

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 are designated as "held-for-trading" and are measured at fair value. Accounts receivable and accrued revenues and the Partnership Contribution Receivable and partner loans receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the Partnership Contribution Payable and partner loans payable and long-term debt are designated as "other financial liabilities". Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt and amortized using the effective interest method.

Derivative Financial Instruments

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 using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to crude oil and natural gas commodity prices are recognized in crude oil and natural gas 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 to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes.

Policies and procedures are in place 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) Reclassification

In addition to the restatement required due to the changes in operating segments (see Note 1), certain information provided for prior years has been reclassified to conform to the presentation adopted in 2010.

T) Recent Accounting Pronouncements

Beginning with the three month period ending March 31, 2011, Cenovus is required to report its results in accordance with International Financial Reporting Standards ("IFRS"). Cenovus has developed a detailed changeover plan to complete the transition to IFRS. The plan includes the preparation of required comparative information for 2010, given that the IFRS date of transition was January 1, 2010. The Company is on schedule with its plan and is continuing to assess the potential impact of the adoption of IFRS on its Consolidated Financial Statements.

5. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

BUSINESS COMBINATIONS

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations," which replaces CICA Handbook Section 1581 of the same name. The new 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. This accounting policy was applied to the November 1, 2010 purchase of the marine terminal facilities disclosed in Note 6.

CONSOLIDATED FINANCIAL STATEMENTS AND NON-CONTROLLING INTERESTS

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements." Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest 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 early adoption of these standards did not have a material impact on the Company's Consolidated Financial Statements for the year ended December 31, 2010. These standards along with CICA Handbook Section 1582 above are converged with IFRS (see Note 4).

6. ASSETS AND LIABILITIES HELD FOR SALE

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million.

Cenovus intends to sell the facilities as soon as practicable. As a result, the net assets acquired have been recorded at estimated fair value less costs to sell, and have been classified as held for sale. These assets are reported in the Refining and Marketing segment. Cenovus recognized a bargain purchase gain of $12 million, resulting from the excess fair value of the net assets acquired over the cash consideration paid. The table below represents the purchase cost and the preliminary allocation to the assets and liabilities. The gain has been recorded in other income.

Cash consideration	38
Fair value of Liabilities assumed	
Asset retirement obligation	5
Future income taxes	4
Total Purchase Price and Liabilities Assumed	47
Estimated Fair Value of Assets acquired	
Property, Plant and Equipment	59
Bargain Purchase Gain	12

As at December 31, 2010 the assets and liabilities classified as held for sale consists of the following:

	December 31, 2010
Assets Held for Sale	
Property, plant and equipment	65
Liabilities Related to Assets Held for Sale	
Asset retirement obligation	5
Future income taxes	2
	7

7. DIVESTITURES

For the years ended December 31,	**2010**	2009	2008
Oil Sands	**81**	89	8
Conventional	**221**	130	40
Corporate	**7**	3	–
Cash Proceeds	**309**	222	48

8. INTEREST, NET

For the years ended December 31,	2010	2009	2008
Interest Expense–Long-Term Debt	**227**	211	205
Interest Expense–Other	**196**	220	228
Interest Income	**(144)**	(187)	(200)
	279	244	233

Interest Expense–Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively (See Note 11).

9. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2010	2009	2008
Unrealized Foreign Exchange (Gain) Loss on translation of:			
U.S. dollar debt issued from Canada	**(182)**	(381)	430
U.S. dollar Partnership Contribution Receivable issued from Canada	**91**	504	(744)
Other	**22**	204	(3)
Unrealized Foreign Exchange (Gain) Loss	**(69)**	327	(317)
Realized Foreign Exchange (Gain) Loss	**18**	(23)	9
	(51)	304	(308)

10. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31,	2010	2009	2008
Current			
Canada	**82**	979	393
United States	**–**	(45)	(24)
Total Current Tax	**82**	934	369
Future Tax	**88**	(590)	405
	170	344	774

Future income tax expense in 2010 includes a tax benefit of $107 million from the recognition of net capital losses expected to be realized against future capital gains. These net capital losses are attributable to an internal restructuring undertaken in 2010. Net capital losses of $415 million, attributable to the restructuring and to realized foreign exchange losses, are unrecognized at December 31, 2010. Recognition is dependent on the level of future capital gains.

Current income tax expense in 2009 includes the incremental tax incurred as a result of certain corporate restructuring transactions which were required to effect the Arrangement.

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

For the years ended December 31,	**2010**	2009	2008
Earnings Before Income Tax	**1,163**	1,162	3,300
Canadian Statutory Rate	**28.2%**	29.2%	29.7%
Expected Income Tax	**328**	339	980
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(33)**	(1)	(92)
Non-deductible stock-based compensation	**29**	–	–
Multi-jurisdictional financing	**(93)**	(134)	(135)
Foreign exchange gains not included in net earnings	**28**	58	71
Non-taxable capital (gains) losses	**(9)**	30	(53)
Recognition of capital losses	**(107)**	–	–
Other	**27**	52	3
	170	344	774
Effective Tax Rate	**14.6%**	29.6%	23.5%

The net future income tax liability consists of:

As at December 31,	**2010**	2009
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,534**	2,654
Timing of partnership items	**125**	9
Net foreign exchange gains	**127**	61
Risk management	**55**	17
Other	**55**	1
Future Tax Assets		
Unused tax losses	**(281)**	(242)
Risk management	**(45)**	(33)
Other	**(166)**	–
Net Future Income Tax Liability	**2,404**	2,467

The approximate amounts of tax pools available are as follows:

As at December 31,	**2010**	2009
Canada	**4,239**	3,754
United States	**3,082**	2,637
	7,321	6,391

Included in the above tax pools are $236 million (2009–$491 million) of Canadian non-capital losses which expire no earlier than 2026 and $607 million (2009–$232 million) of U.S. net operating losses which expire no earlier than 2029.

Also included in the above tax pools are $983 million (2009–$51 million) of Canadian net capital losses, available for carry forward to reduce future capital gains.

11. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In connection with the Arrangement with Encana, Cenovus acquired Encana's assets which are jointly controlled with ConocoPhillips. On January 2, 2007, Encana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consists of an upstream entity and a refining entity. The upstream entity contribution included assets from Encana, primarily the Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable (Partnership Contribution Receivable) contributed from ConocoPhillips of an equal amount. For the refining entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Encana contributed a note payable (Partnership Contribution Payable) of US$7.5 billion.

In accordance with Canadian GAAP, these entities have been accounted for using the proportionate consolidation method with the results of operations included in the Upstream and Refining and Marketing segments (See Note 1).

PARTNERSHIP CONTRIBUTION RECEIVABLE

This note receivable is denominated in US$ and 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 Partnership Contribution Receivable shown in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of payments to date.

MANDATORY RECEIPTS

	2011	2012	2013	2014	2015	Thereafter	**Total**
Partnership Contribution Receivable–US$	348	366	386	407	429	569	**2,505**
Partnership Contribution Receivable–C$ equivalent	346	364	384	405	427	565	**2,491**

PARTNERSHIP CONTRIBUTION PAYABLE

This note payable is denominated in US$ and bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Payable amounts shown in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of payments to date.

MANDATORY PAYMENTS

	2011	2012	2013	2014	2015	Thereafter	**Total**
Partnership Contribution Payable–US$	345	366	388	412	437	584	**2,532**
Partnership Contribution Payable–C$ equivalent	343	364	386	410	435	581	**2,519**

In addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities include equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements. At December 31, 2010 these amounts were $274 million (December 31, 2009–$183 million).

12. INVENTORIES

As at December 31,	**2010**	2009
Product		
Upstream – Oil Sands	**80**	84
Refining and Marketing	**779**	772
Parts and Supplies	**21**	19
	880	875

As a result of a significant decline in commodity prices in the latter half of 2008, Cenovus recorded a write-down of its product inventory by $186 million from cost to net realizable value at December 31, 2008. Product turnover and the improvement in commodity prices has resulted in all of the 2008 write-down being reversed, $178 million in 2009 and $8 million in 2010.

The total amount of inventories recognized as an expense during the year was $5,997 million (2009–$4,999 million; 2008–$9,322 million).

13. PROPERTY, PLANT AND EQUIPMENT, NET

	2010			2009		
As at December 31,	**Cost**	**Accumulated DD&A***	**Net**	Cost	Accumulated DD&A*	Net
Upstream	**22,691**	**(12,495)**	**10,196**	21,550	(11,455)	10,095
Refining and Marketing	**5,883**	**(695)**	**5,188**	5,537	(534)	5,003
Corporate and Eliminations	**446**	**(300)**	**146**	390	(274)	116
	29,020	**(13,490)**	**15,530**	27,477	(12,263)	15,214

* Depreciation, depletion and amortization

Upstream property, plant and equipment includes internal costs directly related to exploration, development and construction activities of $102 million (2009–$117 million). Costs classified as general and administrative expenses have not been capitalized as part of the capital expenditures.

Costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. Refining assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31,	**2010**	2009	2008
Upstream	**758**	644	278
Refining and Marketing	**1,673**	1,366	598
	2,431	2,010	876

The Canadian prices used in the ceiling test evaluation of Cenovus's crude oil and natural gas reserves at December 31, 2010 were:

	2011	2012	2013	2014	2015	Average Annual % Change to 2022
WTI (US$/barrel)	85.00	87.70	90.50	93.40	96.30	2%
AECO ($/Mcf)	4.25	4.90	5.40	5.90	6.35	4%
Crude Oil ($/barrel)	64.75	66.32	65.08	66.59	68.71	2%
Natural Gas Liquids ($/barrel)	62.19	66.27	68.94	71.25	73.58	2%
Natural Gas ($/Mcf)	4.05	4.70	5.20	5.70	6.14	4%

During the year ended December 31, 2010, it was determined that a processing unit at the Borger refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, the carrying amount of the unit was reduced to zero and an impairment loss of $37 million net to Cenovus, was recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income within the Refining and Marketing segment.

14. OTHER ASSETS

As at December 31,	2010	2009
Partner Loans	**274**	183
Deferred Asset–Refining and Marketing	**99**	121
Deferred Pension Plan and Savings Plan	**11**	9
Other	**7**	7
	391	320

15. LONG-TERM DEBT

As at December 31,	Note	2010	2009
Canadian Dollar Denominated Debt			
Revolving term debt*	A	**–**	32
U.S. Dollar Denominated Debt			
Revolving term debt*	A	**–**	26
Unsecured notes	B	**3,481**	3,663
		3,481	3,689
Total Debt Principal		**3,481**	3,721
Debt Discounts and Transaction Costs	C	**(49)**	(65)
Current Portion of Long-Term Debt	D	**–**	–
		3,432	3,656

* Revolving term debt includes commercial paper, bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

The weighted average interest rate on outstanding debt for the year ended December 31, 2010 was 5.8 percent (2009–5.5 percent).

A) Revolving Term Debt

At December 31, 2010, Cenovus had in place a committed credit facility in the amount of C$2,500 million or its equivalent amount in U.S. dollars. The committed credit facility matures on November 30, 2014 and is extendable from time to time for a period of up to four years at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. At December 31, 2010, no amounts were drawn on Cenovus's committed bank credit facility (2009–$58 million).

B) Unsecured Notes

In conjunction with the Arrangement, on September 18, 2009 Cenovus completed a private offering of senior unsecured notes of an aggregate principal amount of US$3,500 million. The notes were disclosed on Cenovus's Consolidated Balance Sheets as a long term liability, net of financing costs as at September 30, 2009. The net proceeds of $3,718 million were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement. Cenovus placed an additional $162 million into the escrow account so that the total escrowed funds of $3,880 million would be sufficient to pay the special mandatory redemption price for the notes if the Arrangement did not proceed. Upon completion of the Arrangement, funds were released from escrow and the proceeds of the notes were used to pay the note payable to Encana of US$3,500 million as part of the Arrangement. On November 30, 2009 these notes became the direct, unsecured obligations of Cenovus. In 2010, substantially all of these notes were exchanged for notes registered under the Securities Act of 1933 with the same terms and conditions as the original issued notes.

	US$ Principal Amount	2010	2009
4.50% due September 15, 2014	**800**	**796**	837
5.70% due October 15, 2019	**1,300**	**1,293**	1,361
6.75% due November 15, 2039	**1,400**	**1,392**	1,465
	3,500	**3,481**	3,663

Cenovus has in place a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1,500 million. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2010, no medium term notes have been issued under this Canadian prospectus. The shelf prospectus expires in July 2012.

Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$1,500 million. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2010, no notes have been issued under this U.S. prospectus. The shelf prospectus expires in August 2012.

At December 31, 2010, the Company is in compliance with all of the terms of its debt agreements.

C) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts are recorded within long-term debt and are being amortized using the effective interest method. During 2010, no transaction costs were recorded within long term debt (2009–$70 million).

D) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	Total C$ Equivalent
2011	–	–	–
2012	–	–	–
2013	–	–	–
2014	800	–	796
2015	–	–	–
Thereafter	2,700	–	2,685
	3,500	–	3,481

16. ASSET RETIREMENT OBLIGATION

The aggregate carrying amount of the obligation associated with the retirement of upstream oil and gas assets and refining facilities is as follows:

As at December 31,	**2010**	2009
Asset Retirement Obligation, Beginning of Year	**1,147**	793
Liabilities Incurred	**44**	6
Liabilities Settled	**(33)**	(38)
Liabilities Divested	**(88)**	(10)
Change in Estimated Future Cash Flows	**69**	357
Accretion Expense	**75**	45
Foreign Currency Translation	**(1)**	(6)
Asset Retirement Obligation, End of Year	**1,213**	1,147

The total undiscounted amount of estimated cash flows required to settle the obligation is $6,093 million (2009–$5,683 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.09 percent (2009–6.23 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 resources at that time.

17. OTHER LIABILITIES

As at December 31,	**2010**	2009
Partner Loans	**274**	183
Deferred Revenue	**37**	40
Other	**35**	16
	346	239

18. SHARE CAPITAL

AUTHORIZED

Cenovus 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

	2010		2009	
As at December 31,	**Number of Common Shares (thousands)**	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**751,309**	**3,681**	–	–
Common Shares Issued Pursuant to the Arrangement	**–**	**–**	751,273	3,680
Common Shares Issued under Stock Option Plans	**1,366**	**35**	36	1
Outstanding, End of Year	**752,675**	**3,716**	751,309	3,681

To determine Cenovus's share capital amount at the time of the Arrangement, Encana's stated capital immediately prior to the Arrangement was split based on the relative fair market values of the Encana and Cenovus Common Shares at the time of the initial exchange. Cenovus's share capital amount was deducted from Encana's net investment with the remaining $6,055 million reclassified as Paid in Surplus.

At December 31, 2010, there were 26 million (2009–24 million) Common Shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at December 31, 2010.

The Company has a dividend reinvestment plan ("DRIP"). Under the DRIP, holders of Common Shares may reinvest all or a portion of the cash dividends payable on their Common Shares in additional Common Shares. At the discretion of the Company, the additional Common Shares may be issued from treasury or purchased on the market.

NET INVESTMENT

For periods prior to the Arrangement, Encana's net investment in the operations of Cenovus is presented as total Net Investment in the Consolidated Financial Statements. Total Net Investment consists of Owner's Net Investment and AOCI.

STOCK-BASED COMPENSATION

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted 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. Options granted prior to February 17, 2010 expire after five years while options granted on February 17, 2010 or later expire after seven years.

All options issued by the Company under the Employee Stock Option Plan have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the right. The tandem stock appreciation rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this note, options with associated tandem stock appreciation rights are referred to as "TSARs".

In addition, certain of the TSARs are performance based ("Performance TSARs"). The Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and have an additional vesting requirement whereby vesting is subject to achievement of prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited.

In accordance with the Arrangement described in Note 2, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's Common Share price relative to that of Encana's Common Share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus Replacement TSARs are measured against the Cenovus Common Share price while Encana Replacement TSARs are measured against the Encana Common Share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

TSARs Held by Cenovus Employees

The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2010:

As at December 31, 2010, (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,402	8,053	16,455	27.52
Granted	6,087	–	6,087	26.54
Exercised for cash payment	(1,099)	(77)	(1,176)	21.32
Exercised as options for shares	(948)	(109)	(1,057)	23.52
Forfeited	(398)	(794)	(1,192)	28.55
Outstanding, End of Year	12,044	7,073	19,117	27.75
Exercisable, End of Year	4,154	3,580	7,734	28.07

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	1,198	–	1,198	0.25	22.96	1,172	–	1,172	22.94
25.00 to 29.99	8,925	4,694	13,619	3.99	26.47	1,818	2,351	4,169	26.59
30.00 to 34.99	1,733	2,379	4,112	2.19	32.87	1,051	1,229	2,280	32.86
35.00 to 39.99	119	–	119	2.44	37.22	72	–	72	37.22
40.00 to 44.99	67	–	67	2.45	43.23	40	–	40	43.23
45.00 to 49.99	2	–	2	2.39	45.56	1	–	1	45.56
	12,044	7,073	19,117	3.35	27.75	4,154	3,580	7,734	28.07

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's employees when these employees exercise a Cenovus Replacement TSAR for cash. No compensation expense is recognized and no further Cenovus Replacement TSARs will be granted to Encana employees.

Cenovus has recorded a liability of $123 million (2009–$84 million) in the Consolidated Balance Sheets for Cenovus Replacement TSARs held by Encana employees using the fair value method, with an offsetting accounts receivable from Encana. The fair value of each Cenovus Replacement TSAR held by Encana employees was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	1.70%
Dividend Yield	2.40%
Volatility	23.99%
Cenovus's Common Share Price	$33.28

The following tables summarize information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2010:

As at December 31, 2010, (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,482	10,463	22,945	27.14
Exercised for cash payment	(3,847)	(411)	(4,258)	22.67
Exercised as options for shares	(105)	(1)	(106)	19.44
Forfeited	(316)	(1,111)	(1,427)	28.80
Outstanding, End of Year	8,214	8,940	17,154	28.16
Exercisable, End of Year	5,977	4,828	10,805	27.88

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	1,658	–	1,658	0.17	22.95	1,650	–	1,650	22.95
25.00 to 29.99	4,116	6,107	10,223	2.19	26.49	2,711	3,368	6,079	26.63
30.00 to 34.99	2,271	2,833	5,104	2.09	32.83	1,515	1,460	2,975	32.74
35.00 to 39.99	90	–	90	2.44	37.24	54	–	54	37.24
40.00 to 44.99	77	–	77	2.44	42.81	46	–	46	42.81
45.00 to 49.99	2	–	2	2.39	45.56	1	–	1	45.56
	8,214	8,940	17,154	1.97	28.16	5,977	4,828	10,805	27.88

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana Replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of $24 million (2009–$70 million) in the Consolidated Balance Sheets for Encana Replacement TSARs held by Cenovus's employees using the fair value method.

The fair value of each Encana Replacement TSAR was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	1.70%
Dividend Yield	2.74%
Volatility	23.57%
Encana's Common Share Price	$29.09

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2010:

As at December 31, 2010, (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,305	8,052	16,357	30.46
Exercised for cash payment	(1,568)	(148)	(1,716)	24.43
Exercised as options for Encana shares	(94)	–	(94)	21.47
Forfeited	(214)	(806)	(1,020)	31.98
Outstanding, End of Year	6,429	7,098	13,527	31.17
Exercisable, End of Year	4,461	3,605	8,066	30.85

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	7	–	7	2.75	23.04	4	–	4	23.06
25.00 to 29.99	4,371	4,718	9,089	2.04	28.59	3,127	2,376	5,503	28.30
30.00 to 34.99	312	–	312	1.75	32.61	274	–	274	32.71
35.00 to 39.99	1,597	2,380	3,977	2.13	36.47	971	1,229	2,200	36.47
40.00 to 44.99	74	–	74	2.49	42.28	45	–	45	42.28
45.00 to 49.99	66	–	66	2.46	47.86	39	–	39	47.86
50.00 to 54.99	2	–	2	2.39	50.39	1	–	1	50.39
	6,429	7,098	13,527	2.06	31.17	4,461	3,605	8,066	30.85

B) Performance Share Units

The Company has granted Performance Share Units ("PSUs") to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a Common Share of Cenovus or a cash payment equal to the value of a Cenovus Common Share. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The following table summarizes information related to the PSUs held by Cenovus employees as at December 31, 2010:

(thousands)	**Outstanding PSUs**
Outstanding, Beginning of Year	**–**
Granted	**1,252**
Cancelled	**(35)**
Units in Lieu of Dividends	**35**
Outstanding, End of Year	**1,252**

C) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. Employees have the option to convert either 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

Pursuant to the terms of the Arrangement, Encana DSUs credited to directors, officers and employees of Cenovus were exchanged for Cenovus DSUs. The fair value of the Cenovus DSUs credited to each holder was based on the fair market value of Cenovus Common Shares relative to Encana Common Shares prior to the effective date of the Arrangement.

The following table summarizes information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2010:

(thousands)	**Outstanding DSUs**
Outstanding, Beginning of Year	**768**
Granted	**65**
Granted from Annual Bonus Awards	**81**
Units in Lieu of Dividends	**26**
Outstanding, End of Year	**940**

D) Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses on the Consolidated Statements of Earnings and Comprehensive Income:

	2010	2009*	2008
TSARs held by Cenovus employees	**52**	(2)	–
Encana Replacement TSARs held by Cenovus employees	**(23)**	32	–
Performance Share Units	**13**	–	–
Deferred Share Units	**9**	–	–
Total stock-based compensation expense (recovery)	**51**	30	–

* 2009 represents one month of compensation expense incurred under the Cenovus plan post Arrangement.

Included in the financial information prior to the Arrangement, the Company recorded compensation expense (recovery) for the following Encana plans:

	2010	2009	2008
Encana TSARs	**–**	4	(5)
Encana DSUs	**–**	3	1
Total stock-based compensation expense (recovery)	**–**	7	(4)

19. CAPITAL STRUCTURE

Cenovus's capital structure is comprised of Shareholders' Equity plus Debt. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent.

As at December 31,	**2010**	2009
Debt	**3,432**	3,656
Shareholders' Equity	**10,022**	9,608
Total Capitalization	**13,454**	13,264
Debt to Capitalization ratio	**26%**	28%

Cenovus targets a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at December 31,	**2010**	2009	2008
Debt	**3,432**	3,656	3,719
Net Earnings	**993**	818	2,526
Add (deduct):			
Interest, net	**279**	244	233
Income tax expense	**170**	344	774
Depreciation, depletion and amortization	**1,310**	1,527	1,397
Accretion of asset retirement obligation	**75**	45	40
Foreign exchange (gain) loss, net	**(51)**	304	(308)
(Gain) loss on divestiture of assets	**9**	–	–
Other (income) loss, net	**(13)**	(2)	3
Adjusted EBITDA	**2,772**	3,280	4,665
Debt to Adjusted EBITDA	**1.2x**	1.1x	0.8x

It is Cenovus's intention to maintain an investment grade rating to ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

Cenovus's capital structure, objectives and targets have remained unchanged since Cenovus's inception. At December 31, 2010, Cenovus is in compliance with all of the terms of its debt agreements.

20. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension plan that includes defined contribution and defined benefit components, and other post-employment benefit plans ("OPEB"). Most of the employees participate in the defined contribution pension; the defined benefit pension component is closed to new entrants.

The Company files an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recently filed valuation was dated November 30, 2009 and the next required actuarial valuation will be as at December 31, 2012.

Information related to defined benefit pension and OPEB plans, based on actuarial estimations is as follows:

	Pension Benefits		OPEB	
As at December 31,	**2010**	2009	**2010**	2009
Accrued Benefit Obligation, End of Year	**68**	56	**14**	11
Fair Value of Plan Assets, End of Year	**59**	54	**–**	–
Funded Status–Plan Assets (less) than Benefit Obligation	**(9)**	(2)	**(14)**	(11)
Amounts Not Recognized:				
Unamortized net actuarial (gain) loss	**20**	15	**1**	(1)
Unamortized past service cost	**–**	–	**–**	1
Accrued Benefit Asset (Liability)	**11**	13	**(13)**	(11)

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

	Pension Benefits		OPEB	
As at December 31,	**2010**	2009	**2010**	2009
Discount Rate	**5.25%**	6.00%	**5.25%**	6.00%
Rate of Compensation Increase	**4.05%**	4.05%	**5.65%**	5.77%

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2011	1	–
2012	2	–
2013	2	1
2014	3	1
2015	4	1
2016 – 2020	23	9
Total	35	12

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable and partner loans, 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.

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable and partner loans approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on market information. At December 31, 2010, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,432 million and the fair value was $3,940 million (December 31, 2009–carrying value–$3,656 million, fair value–$3,964 million).

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement with Encana, the risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

Net Risk Management Position

As at December 31,	**2010**	2009
Risk Management		
Current asset	**163**	60
Long-term asset	**43**	1
	206	61
Risk Management		
Current liability	**163**	70
Long-term liability	**10**	4
	173	74
Net Risk Management Asset (Liability)	**33**	(13)

Of the $33 million net risk management asset balance at December 31, 2010, an asset of $41 million relates to the contract with Encana (2009–net liability of $15 million).

Summary of Unrealized Risk Management Positions

	2010 Risk Management			2009 Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**4**	**159**	**(155)**	8	66	(58)
Natural Gas	**202**	**–**	**202**	53	–	53
Power	**–**	**14**	**(14)**	–	8	(8)
Total Fair Value	**206**	**173**	**33**	61	74	(13)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at December 31,	**2010**	2009
Prices actively quoted	**40**	6
Prices sourced from observable data or market corroboration	**(7)**	(19)
Total Fair Value	**33**	(13)

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, 2010

As at December 31, 2010,	Notional Volumes	Term	Average Price	**Fair Value**
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	28,600 bbls/d	2011	US$85.54/bbl	**(85)**
WTI NYMEX Fixed Price	29,200 bbls/d	2011	C$88.32/bbl	**(58)**
WTI NYMEX Fixed Price	5,000 bbls/d	2012	US$92.44/bbl	**(3)**
WTI NYMEX Fixed Price	3,000 bbls/d	2012	C$93.82/bbl	**(1)**
Other Fixed Price Contracts *		2011		**4**
Other Financial Positions **				**(12)**
Crude Oil Fair Value Position				**(155)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	379 MMcf/d	2011	US$5.70/Mcf	**158**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**41**
AECO Fixed Price	80 MMcf/d	2012	C$4.49/Mcf	**–**
Other Fixed Price Contracts *		2011-2013		**3**
Natural Gas Fair Value Position				**202**
Power Purchase Contracts				
Power Fair Value Position				**(14)**

* Cenovus has entered into fixed priced swaps to protect against widening price differentials between production areas in Canada and various sales points.

** Other financial positions are part of ongoing operations to market the Company's production.

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss)		
For the years ended December 31,	**2010**	2009	2008
Gross Revenues	**272**	1,154	(305)
Less: Royalties	**–**	–	–
Net Revenues	**272**	1,154	(305)
Operating Expenses and Other	**6**	(38)	31
Gain (Loss) on Risk Management	**278**	1,116	(274)

	Unrealized Gain (Loss)		
For the years ended December 31,	**2010**	2009	2008
Gross Revenues	**60**	(668)	890
Less: Royalties	**–**	–	–
Net Revenues	**60**	(668)	890
Operating Expenses and Other	**(14)**	(30)	9
Gain (Loss) on Risk Management	**46**	(698)	899

Reconciliation of Unrealized Risk Management Positions

For the years ended December 31,	**2010**		2009	2008
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**(13)**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**324**	**324**	418	625
Fair Value of Contracts Realized During the Year	**(278)**	**(278)**	(1,116)	274
Fair Value of Contracts, End of Year	**33**	**46**	(698)	899

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, Management believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax at December 31, 2010 as follows:

	10% Price Increase	**10% Price Decrease**
Crude oil price	**(227)**	**227**
Natural gas price	**(104)**	**104**
Power price	**6**	**(6)**

C) Risks Associated with Financial Assets and Liabilities

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 Company's policy is not to use derivative financial instruments for speculative purposes.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending with fixed price swaps. To help protect against widening crude oil price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX and AECO prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

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 that 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. Agreements are entered into with major financial institutions with investment grade credit ratings or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2010, over 92 percent (2009–98 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2010, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (2009– three counterparties, including Encana) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the Partnership Contribution Receivable and the partner loans receivable is the total carrying value. The current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt. As disclosed in Note 19, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. At December 31, 2010, Cenovus's committed credit facility was fully available. In addition Cenovus had $1,500 million in unused capacity under its Canadian shelf prospectus and US$1,500 million in unused capacity under its U.S. shelf prospectus, the availability of which are dependent on market conditions.

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	1,825	–	–	–	**1,825**
Risk Management Liabilities	163	10	–	–	**173**
Long-Term Debt (1) (2)	203	407	1,167	5,236	**7,013**
Partnership Contribution Payable (1)	486	972	972	609	**3,039**
Partner Loans Payable	–	274	–	–	**274**

(1) Principal and interest, including current portion

(2) No principal repayment until 2014 and thereafter (see Note 15D)

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results. Cenovus's functional currency and reporting currency is Canadian dollars. All amounts are reported in Canadian dollars, unless otherwise indicated.

As disclosed in Note 9, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At December 31, 2010, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,525 million at December 31, 2009) and US$2,505 million related to the U.S. dollar Partnership Contribution Receivable (US$2,834 million at December 31, 2009). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $10 million change in foreign exchange (gain) loss at December 31, 2010 (2009–$7 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2010, one hundred percent of the Company's debt was fixed-rate debt and as a result, had interest rates on floating rate debt changed by one percent there would be no impact on net earnings (December 31, 2009–$nil; 2008–$5 million). This assumes the amount of fixed and floating debt remains unchanged from December 31, 2010.

22. SUPPLEMENTARY INFORMATION

A) Per Share Amounts

For the years ended December 31, (millions)	**2010**	2009	2008
Weighted Average Common Shares Outstanding – Basic	**751.9**	751.0	750.1
Effect of Stock Options and Other Dilutive Securities	**0.8**	0.4	1.7
Weighted Average Common Shares Outstanding – Diluted	**752.7**	751.4	751.8

Since Cenovus's shares were issued pursuant to the Arrangement, the per share amounts disclosed for 2009 and 2008 are based on the number of Encana's Common Shares outstanding.

B) Supplementary Cash Flow Information

For the years ended December 31,	**2010**	2009	2008
Interest Paid	**423**	426	422
Income Taxes Paid	**62**	1,284	542

Income taxes paid in 2009 includes amounts paid to Encana as a result of the dissolution of a partnership in connection with the Arrangement.

23. COMMITMENTS AND CONTINGENCIES

A) Commitments

As part of normal operations, the Company has committed to certain amounts over the next five years and thereafter as follows:

	2011	2012	2013	2014	2015	Thereafter	Total
Operating Leases (Building Leases)	33	87	88	85	78	1,553	1,924
Pipeline Transportation [1]	107	93	167	167	166	953	1,653
Purchases of Goods and Services	157	23	12	10	7	23	232
Capital Commitments	91	71	4	4	4	14	188
Product Purchases	23	18	18	18	18	7	102
Other Long-Term Commitments	4	2	1	1	–	1	9
Total Payments	415	294	290	285	273	2,551	4,108
Product Sales	50	52	54	56	57	63	332

[1] Certain transportation commitments included are subject to regulatory approval

At December 31, 2010, there were outstanding letters of credit aggregating $23 million issued as security for performance under certain contracts (2009–$13 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 21.

B) Contingencies

Legal Proceedings

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

Asset Retirement

Cenovus is responsible for the retirement of long-lived assets related to its oil and gas properties, refining facilities and midstream facilities at the end of their useful lives. Cenovus has recognized a liability of $1,218 million, including $5 million that has been classified as Liabilities Related to Assets Held for Sale, 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 tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Cenovus 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 applicable to Cenovus are described in this note. The most notable differences are:

- full cost accounting;
- pensions and other post-employment benefits;
- liability-based stock compensation plans;
- income taxes;
- other comprehensive income; and
- joint venture accounting.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31,	Note 24	2010	2009	2008
Net Earnings–Canadian GAAP		**993**	818	2,526
Increase (Decrease) in Net Earnings Under U.S. GAAP:				
Operating expense	C ii)	**9**	4	(13)
Depreciation, depletion and amortization expense	A, C ii)	**107**	239	21
General and administrative expense	C ii)	**11**	9	(17)
Stock-based compensation expense		**–**	–	1
Income tax expense	D	**(87)**	(199)	(138)
Net Earnings–U.S. GAAP		**1,033**	871	2,380

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31,	Note 24	2010	2009	2008
Gross Revenues		**13,422**	11,790	18,103
Less: Royalties		**449**	273	533
Net Revenues		**12,973**	11,517	17,570
Expenses				
Production and mineral taxes		**34**	44	80
Transportation and blending		**1,065**	760	1,021
Operating	C ii)	**1,293**	1,308	1,305
Purchased product		**7,549**	5,910	10,341
Depreciation, depletion and amortization	A, C ii)	**1,203**	1,288	1,376
General and Administrative	C ii)	**240**	202	188
Interest, net		**279**	244	233
Accretion of asset retirement obligation		**75**	45	40
Foreign exchange (gain) loss, net		**(51)**	304	(308)
Stock-based compensation–options		**–**	–	(1)
(Gain) loss on divestiture of assets		**9**	–	–
Other (income) loss, net		**(13)**	(2)	3
		11,683	10,103	14,278
Earnings Before Income Tax		**1,290**	1,414	3,292
Income tax expense	D	**257**	543	912
Net Earnings – U.S. GAAP		**1,033**	871	2,380
Other Comprehensive Income (Loss), Net of Tax				
Foreign Currency Translation Adjustment		**(13)**	(238)	347
Compensation Plans		**(7)**	32	(9)
Comprehensive Income		**1,013**	665	2,718

CONDENSED CONSOLIDATED BALANCE SHEETS – U.S. GAAP

		2010		2009	
As at December 31,	Note 24	**As Reported**	**U.S. GAAP**	As Reported	U.S. GAAP
Assets					
Current Assets		**2,775**	**2,775**	2,453	2,453
Assets Held for Sale		**65**	**65**	–	–
Property, Plant and Equipment	A, B, C ii)				
(includes unproved properties and major development projects of $2,428 and $2,010 as of December 31, 2010 and 2009, respectively)		**29,020**	**28,997**	27,477	27,455
Accumulated Depreciation, Depletion and Amortization		**(13,490)**	**(14,045)**	(12,263)	(12,925)
Property, Plant and Equipment, net		**15,530**	**14,952**	15,214	14,530
(Full Cost Method for Oil and Gas Activities)					
Partnership Contribution Receivable		**2,145**	**2,145**	2,621	2,621
Risk Management		**43**	**43**	1	1
Other Assets	C i)	**391**	**390**	320	319
Goodwill		**1,146**	**1,146**	1,146	1,146
		22,095	**21,516**	21,755	21,070
Liabilities and Shareholders' Equity					
Current Liabilities	C i), C ii), D	**2,485**	**2,644**	1,984	2,098
Liabilities Related to Assets Held for Sale		**7**	**7**	–	–
Long-Term Debt		**3,432**	**3,432**	3,656	3,656
Partnership Contribution Payable		**2,176**	**2,176**	2,650	2,650
Risk Management		**10**	**10**	4	4
Asset Retirement Obligation		**1,213**	**1,213**	1,147	1,147
Other Liabilities	C i), C ii)	**346**	**348**	239	239
Deferred Income Taxes	D	**2,404**	**2,331**	2,467	2,368
		12,073	**12,161**	12,147	12,162
Shareholders' Equity	E	**10,022**	**9,355**	9,608	8,908
		22,095	**21,516**	21,755	21,070

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – U.S. GAAP

For the years ended December 31,	**2010**	2009	2008
Operating Activities			
Net earnings	**1,033**	871	2,380
Depreciation, depletion and amortization	**1,203**	1,288	1,376
Deferred income taxes	**116**	(396)	554
Unrealized (gain) loss on risk management	**(46)**	698	(899)
Unrealized foreign exchange (gain) loss	**(69)**	327	(317)
Accretion of asset retirement obligation	**75**	45	40
(Gain) loss on divestiture of assets	**9**	–	–
Other (income) loss, net	**35**	7	(20)
Net change in other assets and liabilities	**(55)**	(26)	(92)
Net change in non-cash working capital	**293**	225	202
Cash From Operating Activities	**2,594**	3,039	3,224
Cash (Used in) Investing Activities	**(1,796)**	(2,063)	(2,109)
Net Cash Provided before Financing Activities	**798**	976	1,115
Cash From (Used in) Financing Activities	**(631)**	(977)	(1,226)

NOTES

A) Full Cost Accounting

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in a 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 oil and gas prices at the balance sheet date, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs. For 2010 and 2009, depletion charges under U.S. GAAP were also calculated by reference to proved reserves estimated using an average price for the prior 12-month period. For 2008, depletion charges under U.S. GAAP were calculated by reference to proved reserves estimated using oil and gas prices at the balance sheet date.

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, 2008, Cenovus's capitalized costs of oil and gas properties in Canada exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $73 million charged to DD&A. Additional depletion was also recorded in certain prior years, as a result of ceiling test differences 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 resulted in a decrease to DD&A of $107 million (2009–$237 million; 2008–$98 million).

B) Property, Plant and Equipment Allocation

For periods prior to the Arrangement, net property, plant and equipment related to Canadian upstream oil and gas activities have been allocated for U.S. GAAP carve-out purposes using the same methodology as the carve-out allocation for Canadian GAAP purposes.

The balances related to Canadian upstream operations have been allocated between Cenovus and Encana in accordance with the CICA Handbook Accounting Guideline AcG-16, based on the ratio of future net revenue, discounted at 10 percent, of the properties carved out to the discounted future net revenue of all proved properties in Canada using the reserve reports dated December 31, 2008. Future net revenue is the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves, the value of which has been determined by independent qualified reserve evaluators.

C) Compensation Plans

i) Pensions and Other Post-Employment Benefits

Under U.S. GAAP, ASC 715-30, "Compensation – Retirement Benefits", requires Cenovus 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 recognition of 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, Cenovus adopted ASC 718, *"Compensation – Stock Compensation"* for the year ended December 31, 2006 using the modified-prospective approach. Under ASC 718, liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights and performance share appreciation rights, 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 crude oil and natural gas development activities, certain 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 property, plant and equipment decreased by $1 million (2009–$25 million decrease)
- Current liabilities decreased by $14 million (2009–$41 million decrease)
- Other liabilities decreased by $7 million (2009–$1 million increase)
- Operating expenses decreased by $9 million (2009–$4 million decrease)
- Administrative expenses decreased by $11 million (2009–$9 million decrease)
- No adjustment was made to depreciation, depletion and amortization expenses (2009–$2 million decrease)

D) Income Taxes

U.S. GAAP uses enacted tax rates and legislative changes to calculate current and deferred income taxes, whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2009, Cenovus incurred losses in one of its subsidiary companies which were recognized and included in calculating future income taxes for Canadian GAAP purposes on the basis that the tax legislative changes were substantially enacted. For U.S. GAAP, these losses were not recognized as the tax legislative changes were not enacted by December 31, 2009 nor December 31, 2010. There was no additional impact to income tax expense in 2010 (2009–$131 million, 2008–nil). In 2010 some of these losses were claimed to reduce the current taxes payable under Canadian GAAP. For U.S. GAAP the losses were not available and the current tax payable increased by $59 million offset by a decrease to the deferred income tax payable with no impact on total tax expense.

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

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

For the years ended December 31,	**2010**	2009	2008
Earnings Before Income Tax–U.S. GAAP	**1,290**	1,414	3,292
Canadian Statutory Rate	**28.2%**	29.2%	29.7%
Expected Income Tax	**364**	413	977
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(36)**	(7)	(88)
Non-deductible stock-based compensation	**32**	–	–
Multi-jurisdictional financing	**(93)**	(134)	(135)
Foreign exchange gains not included in net earnings	**28**	58	71
Non-taxable capital (gains) losses	**(9)**	30	(53)
Recognition of capital losses	**(107)**	–	–
Unrecognized non-capital losses	**–**	131	–
Other	**78**	52	140
Income Tax–U.S. GAAP	**257**	543	912
Effective Tax Rate	**19.9%**	38.4%	27.7%

The net deferred income tax liability consists of:

As at December 31,	2010	2009
Deferred Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,390**	2,407
Timing of partnership items	**125**	9
Net foreign exchange gains	**127**	–
Risk management	**55**	17
Other	**55**	79
Deferred Tax Assets		
Unused tax losses	**(209)**	(111)
Risk management	**(45)**	(33)
Other	**(167)**	–
Net Deferred Income Tax Liability	**2,331**	2,368

E) Other Comprehensive Income

ASC 715-30 requires a change in the funded status of defined benefit and post-employment plans to be recognized on the balance sheet and changes in the funded status through other comprehensive income. In 2010, a loss of $7 million, net of tax was recognized in other comprehensive income (2009– gain of $32 million) as noted in D i). On adoption of ASC 715-30, as required, the transitional amount of $24 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

F) Joint Venture with ConocoPhillips

Under Canadian GAAP, the Refining operations that are jointly controlled are proportionately consolidated. U.S. GAAP requires the Refining operations be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments does not require reconciliation from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity, which is the case for the Refining operations. Equity accounting for the Refining operations would have no impact on Cenovus's net earnings or retained earnings. As required, the following disclosures are provided for the Refining operations of the joint venture.

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31,	2010	2009
Operating Cash Flow (See Note 1)	**67**	358
Depreciation, depletion and amortization	**(229)**	(220)
Other	**(12)**	(12)
Net Earnings (Loss)	**(174)**	126

CONSOLIDATED BALANCE SHEETS

As at December 31,	2010	2009
Current Assets	**951**	808
Long-term Assets	**5,275**	5,104
Current Liabilities	**559**	511
Long-term Liabilities	**327**	410

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,	2010	2009
Cash From (Used in) Operating Activities	**117**	(62)
Cash From (Used in) Investing Activities	**(657)**	(1,034)

For the period ended December 31, 2010
Canadian Dollars/Canadian Protocol

FINANCIAL STATISTICS

(C$ millions, except per share amounts)	**2010**					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Revenues	**13,422**	3,280	3,222	3,318	3,602	11,790	3,103	3,080	2,871	2,736
Less: Royalties	**449**	108	107	123	111	273	98	79	53	43
Net Revenues	**12,973**	3,172	3,115	3,195	3,491	11,517	3,005	3,001	2,818	2,693
Operating Cash Flow										
Crude Oil and Natural Gas Liquids										
Foster Creek and Christina Lake	**765**	195	179	176	215	663	232	198	162	71
Pelican Lake	**287**	58	71	71	87	302	84	98	75	45
Conventional	**751**	175	191	163	222	753	203	218	199	133
Natural Gas	**1,081**	253	246	268	314	2,061	412	500	555	594
Other Upstream Operations	**16**	6	–	7	3	42	10	22	4	6
	2,900	687	687	685	841	3,821	941	1,036	995	849
Refining and Marketing	**75**	125	(27)	(20)	(3)	368	13	98	178	79
Operating Cash Flow	**2,975**	812	660	665	838	4,189	954	1,134	1,173	928
Cash Flow Information										
Cash from Operating Activities	**2,594**	658	645	471	820	3,039	150	1,414	793	682
Deduct (Add back):										
Net change in other assets and liabilities	**(55)**	(14)	(13)	(13)	(15)	(26)	(14)	(3)	(6)	(3)
Net change in non-cash working capital	**234**	24	149	(53)	114	220	(71)	493	(146)	(56)
Cash Flow [(1)]	**2,415**	648	509	537	721	2,845	235	924	945	741
Per share – Basic	**3.21**	0.86	0.68	0.71	0.96	3.79	0.31	1.23	1.26	0.99
– Diluted	**3.21**	0.86	0.68	0.71	0.96	3.79	0.31	1.23	1.26	0.99
Operating Earnings [(2)]	**794**	140	159	142	353	1,522	169	427	512	414
Per share – Diluted	**1.06**	0.19	0.21	0.19	0.47	2.03	0.23	0.57	0.68	0.55
Net Earnings	**993**	73	223	172	525	818	42	101	160	515
Per share – Basic	**1.32**	0.10	0.30	0.23	0.70	1.09	0.06	0.13	0.21	0.69
– Diluted	**1.32**	0.10	0.30	0.23	0.70	1.09	0.06	0.13	0.21	0.69
Effective Tax Rates using										
Net Earnings	**14.6%**					29.6%				
Operating Earnings, excluding divestitures	**21.7%**					25.0%				
Canadian Statutory Rate	**28.2%**					29.2%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.971**	0.987	0.962	0.973	0.961	0.876	0.947	0.911	0.857	0.803
Period end	**1.005**	1.005	0.971	0.943	0.985	0.956	0.956	0.933	0.860	0.794

(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, both of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after tax gain/loss on discontinuance, after-tax gain on bargain purchase, 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 Notes 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.

FINANCIAL STATISTICS (CONTINUED)

	2010	2009
Financial Metrics (Non-GAAP measures)		
Debt to Capitalization [1] [2]	**26%**	28%
Debt to Adjusted EBITDA [2] [3]	**1.2x**	1.1x
Return on Capital Employed [4]	**9%**	8%
Return on Common Equity [5]	**10%**	8%

(1) Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity.

(2) Debt is defined as the current and long-term portions of long-term debt.

(3) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest, income taxes, DD&A, accretion of asset retirement obligations, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss).

(4) Calculated, on a trailing twelve-month basis, as net earnings before after tax interest divided by average shareholder's equity plus average debt, including current portion.

(5) Calculated, on a trailing twelve-month basis, as net earnings divided by average shareholder's equity.

Common Share Information

	2010					2009
	Year	Q4	Q3	Q2	Q1	December
Common Shares Outstanding (millions) [1]						
Period end	**752.7**	752.7	752.0	751.8	751.7	751.3
Average – Basic	**751.9**	752.2	751.9	751.7	751.5	751.0
Average – Diluted	**752.7**	752.7	752.0	751.8	751.7	751.4
Price Range ($ per share)						
TSX – C$						
High	**33.40**	33.40	31.00	30.63	27.84	27.18
Low	**24.26**	28.31	26.19	25.83	24.26	24.68
Close	**33.28**	33.28	29.59	27.40	26.53	26.50
NYSE – US$						
High	**33.37**	33.37	30.12	30.66	26.79	25.70
Low	**22.87**	27.78	24.61	23.84	22.87	23.37
Close	**33.24**	33.24	28.77	25.79	26.21	25.20
Dividends Paid ($ per share) [2]	**C$0.80**	C$0.20	C$0.20	C$0.20	C$0.20	US$0.20
Share Volume Traded (millions)	**787.7**	153.3	188.0	241.9	204.5	83.5

(1) Cenovus Common Shares were issued under the terms of the plan of arrangement with Encana Corporation ("Arrangement") on November 30, 2009 and began trading on December 3, 2009 (TSX) and December 9, 2009 (NYSE).

(2) Dividend paid in December 2009 reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flows.

FINANCIAL STATISTICS (CONTINUED)

Net Capital Investment

(C$ millions)	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Upstream										
Foster Creek	**278**	110	59	52	57	262	76	62	59	65
Christina Lake	**346**	106	93	84	63	224	66	53	49	56
Total	**624**	216	152	136	120	486	142	115	108	121
Pelican Lake	**104**	37	17	28	22	72	13	12	16	31
Other Oil Sands	**139**	60	17	19	43	71	5	5	15	46
Conventional	**523**	216	136	68	103	466	97	91	83	195
	1,390	529	322	251	288	1,095	257	223	222	393
Refining and Marketing	**656**	139	147	166	204	1,033	229	291	264	249
Corporate	**76**	38	11	26	1	34	21	1	2	10
Capital Investment	**2,122**	706	480	443	493	2,162	507	515	488	652
Acquisitions	**86**	48	4	34	–	148	146	1	1	–
Divestitures	**(307)**	5	(168)	(72)	(72)	(367)	(366)	2	(3)	–
Net Acquisition and Divestiture Activity	**(221)**	53	(164)	(38)	(72)	(219)	(220)	3	(2)	–
Net Capital Investment	**1,901**	759	316	405	421	1,943	287	518	486	652

OPERATING STATISTICS - BEFORE ROYALTIES

Upstream Production Volumes

	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)* (1)										
Oil Sands – Heavy										
Foster Creek	**51,147**	52,183	50,269	51,010	51,126	37,725	47,017	40,367	34,729	28,554
Christina Lake	**7,898**	8,606	7,838	7,716	7,420	6,698	7,319	6,305	6,530	6,635
Total	**59,045**	60,789	58,107	58,726	58,546	44,423	54,336	46,672	41,259	35,189
Pelican Lake	**22,966**	21,738	23,259	23,319	23,565	24,870	23,804	25,671	23,989	26,029
Other (including Senlac)	**–**	–	–	–	–	3,057	2,221	5,080	2,574	2,334
	82,011	82,527	81,366	82,045	82,111	72,350	80,361	77,423	67,822	63,552
Conventional Liquids										
Heavy Oil	**16,659**	16,553	16,921	16,205	16,962	17,888	17,127	18,073	18,074	18,290
Light and Medium Oil	**29,346**	29,323	28,608	29,150	30,320	30,394	30,644	29,749	30,189	31,004
Natural Gas Liquids (2)	**1,171**	1,190	1,172	1,166	1,156	1,206	1,183	1,242	1,184	1,213
Total Crude Oil and Natural Gas Liquids	**129,187**	129,593	128,067	128,566	130,549	121,838	129,315	126,487	117,269	114,059
Natural Gas *(MMcf/d)*										
Oil Sands	**43**	39	44	46	45	53	47	55	57	52
Conventional	**694**	649	694	705	730	784	750	775	799	814
Total Natural Gas Production	**737**	688	738	751	775	837	797	830	856	866

(1) Certain volumes for prior periods have been reclassified to conform to current liquids classification.

(2) Natural gas liquids include condensate volumes.

OPERATING STATISTICS - BEFORE ROYALTIES (CONTINUED)

Average Royalty Rates

	2010					2009				
(excluding impact of realized financial hedging)	**Year**	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek	**16.2%**	20.4%	17.9%	19.0%	9.7%	2.7%	3.9%	3.0%	1.5%	1.4%
Christina Lake	**3.9%**	3.6%	3.9%	4.4%	4.0%	2.3%	3.6%	2.9%	1.6%	1.0%
Pelican Lake	**21.1%**	21.2%	18.5%	23.3%	21.4%	20.1%	19.3%	20.0%	19.9%	21.7%
Conventional										
Weyburn	**22.2%**	18.8%	23.2%	23.3%	23.3%	19.7%	27.8%	19.9%	17.2%	10.3%
Other	**8.2%**	7.2%	7.1%	9.1%	9.1%	7.2%	8.4%	9.1%	6.6%	2.4%
Natural Gas Liquids	**1.9%**	1.0%	2.4%	2.0%	2.1%	1.6%	1.6%	2.1%	1.9%	1.0%
Natural Gas	**1.6%**	1.7%	2.4%	1.7%	2.8%	1.5%	3.9%	0.5%	−0.9%	2.8%

Refining

	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [(1)]										
Crude oil capacity *(Mbbls/d)*	**452**	452	452	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**386**	410	401	379	355	394	348	425	404	398
Crude utilization *(%)*	**86%**	91%	89%	84%	79%	87%	77%	94%	89%	88%
Refined products *(Mbbls/d)*	**405**	434	409	398	377	417	370	451	428	421

(1) Represents 100% of the Wood River and Borger refinery operations.

Selected Average Benchmark Prices

	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
West Texas Intermediate ("WTI")	**79.61**	85.24	76.21	78.05	78.88	62.09	76.13	68.24	59.79	43.31
Western Canada Select ("WCS")	**65.38**	67.12	60.56	63.96	69.84	52.43	64.01	58.06	52.37	34.38
Differential – WTI/WCS	**14.23**	18.12	15.65	14.09	9.04	9.66	12.12	10.18	7.42	8.93
Condensate – (C5 @ Edmonton)	**81.91**	85.24	74.53	82.87	84.98	61.35	74.42	65.76	58.07	46.26
Differential – WTI/Condensate (premium)/discount	**(2.30)**	–	1.68	(4.82)	(6.10)	0.74	1.71	2.48	1.72	(2.95)
Refining Margins 3-2-1 Crack Spreads [(1)] *(US$/bbl)*										
Chicago	**9.33**	9.25	10.34	11.60	6.11	8.54	5.00	8.48	10.95	9.75
Midwest Combined (Group 3)	**9.48**	9.12	10.60	11.38	6.82	8.09	5.52	8.06	9.16	9.62
Natural Gas Prices										
AECO *($/GJ)*	**3.91**	3.39	3.52	3.66	5.08	3.92	4.01	2.87	3.47	5.34
NYMEX *(US$/MMBtu)*	**4.39**	3.80	4.38	4.09	5.30	3.99	4.17	3.39	3.50	4.89
Differential – NYMEX/AECO *(US$/MMBtu)*	**0.40**	0.28	0.78	0.32	0.19	0.40	0.19	0.67	0.39	0.35

(1) 3-2-1- Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

OPERATING STATISTICS - BEFORE ROYALTIES (CONTINUED)

Per-unit Results

(C$, excluding impact of realized financial hedging)	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek *($/bbl)* (1)										
Price	**58.76**	58.76	58.51	54.75	63.33	55.55	63.60	62.20	54.43	33.44
Royalties	**9.08**	11.41	9.56	9.38	5.76	1.42	2.31	1.85	0.66	0.22
Transportation and blending	**2.42**	2.54	2.40	2.40	2.33	2.51	1.71	2.50	3.45	2.69
Operating	**10.44**	10.00	10.35	10.36	11.11	11.87	10.43	10.85	11.81	15.91
Netback	**36.82**	34.81	36.20	32.61	44.13	39.75	49.15	47.00	38.51	14.62
Heavy Oil – Christina Lake *($/bbl)* (2)										
Price	**57.96**	58.42	56.45	54.99	62.27	53.45	57.07	64.85	57.32	32.44
Royalties	**2.14**	2.05	2.04	2.19	2.28	1.24	2.04	1.72	0.83	0.23
Transportation and blending	**3.54**	1.54	3.69	4.52	4.47	3.09	0.96	5.36	2.83	3.38
Operating	**16.56**	17.40	15.94	16.50	16.41	16.31	18.06	15.31	13.69	18.21
Netback	**35.72**	37.43	34.78	31.78	39.11	32.81	36.01	42.46	39.97	10.62
Heavy Oil – Pelican Lake *($/bbl)* (3)										
Price	**62.65**	61.38	58.93	62.05	68.04	54.77	62.73	61.87	55.39	38.66
Royalties	**12.96**	12.76	10.62	14.06	14.34	10.98	12.08	12.27	10.93	8.57
Transportation and blending	**1.42**	1.04	1.77	1.52	1.30	0.30	(0.02)	0.67	0.06	0.45
Operating	**12.76**	13.37	13.26	13.29	11.23	9.59	11.64	7.03	9.74	10.15
Netback	**35.51**	34.21	33.28	33.18	41.17	33.90	39.03	41.90	34.66	19.49
Heavy Oil – Oil Sands *($/bbl)* (1) (2) (3)										
Price	**59.76**	59.35	58.41	56.83	64.61	55.09	62.75	62.23	55.18	35.47
Royalties	**9.53**	10.79	9.30	10.03	7.94	4.98	5.37	5.66	4.86	3.69
Production and mineral taxes	**–**	–	–	–	–	0.04	0.02	0.07	0.06	–
Transportation and blending	**2.25**	2.08	2.35	2.35	2.23	1.81	1.14	2.15	2.16	1.85
Operating	**11.70**	11.54	11.83	11.81	11.65	11.49	11.41	9.69	11.53	13.89
Netback	**36.28**	34.94	34.93	32.64	42.79	36.77	44.81	44.66	36.57	16.04
Heavy Oil – Conventional *($/bbl)* (4)										
Price	**63.18**	60.45	59.40	61.35	71.16	55.29	62.09	64.62	56.00	37.71
Royalties	**9.01**	8.01	7.29	9.65	10.99	5.47	8.61	8.39	4.13	0.61
Production and mineral taxes	**0.19**	0.05	0.17	0.10	0.44	0.14	0.13	(0.04)	0.44	0.02
Transportation and blending	**0.56**	0.45	0.60	0.60	0.59	1.91	1.59	1.22	2.75	2.11
Operating	**12.08**	12.47	11.52	12.95	11.45	9.47	12.06	9.31	9.72	6.91
Netback	**41.34**	39.47	39.82	38.05	47.69	38.30	39.70	45.74	38.96	28.06
Total Heavy Oil *($/bbl)* (5)										
Price	**60.33**	59.53	58.59	57.57	65.76	55.14	62.63	62.72	55.36	35.99
Royalties	**9.44**	10.36	8.95	9.97	8.48	5.08	5.95	6.22	4.70	2.98
Production and mineral taxes	**0.03**	0.01	0.03	0.02	0.08	0.06	0.04	0.04	0.14	-
Transportation and blending	**1.97**	1.83	2.04	2.06	1.94	1.83	1.22	1.96	2.28	1.91
Operating	**11.77**	11.68	11.77	11.99	11.61	11.07	11.52	9.61	11.13	12.27
Netback	**37.12**	35.65	35.80	33.53	43.65	37.10	43.90	44.89	37.11	18.83

OPERATING STATISTICS - BEFORE ROYALTIES (CONTINUED)

	2010					2009				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Light and Medium Oil *($/bbl)*										
Price	**71.63**	72.98	68.37	66.14	78.78	63.34	71.82	68.15	65.28	48.09
Royalties	**9.30**	7.69	9.32	10.17	10.05	7.39	11.72	8.09	6.56	3.14
Production and mineral taxes	**2.55**	2.45	2.44	3.08	2.25	2.40	1.70	2.57	1.98	3.37
Transportation and blending	**1.66**	1.89	1.81	1.51	1.45	0.98	0.70	0.83	1.18	1.21
Operating	**12.27**	12.99	12.02	12.84	11.25	9.93	9.53	10.00	9.53	10.67
Netback	**45.85**	47.96	42.78	38.54	53.78	42.64	48.17	46.66	46.03	29.70
Total Crude Oil *($/bbl)*										
Price	**62.98**	62.75	60.86	59.51	68.87	57.22	64.85	64.00	57.95	39.40
Royalties	**9.41**	9.72	9.03	10.01	8.85	5.67	7.34	6.66	5.18	3.03
Production and mineral taxes	**0.62**	0.59	0.59	0.71	0.59	0.65	0.44	0.64	0.62	0.95
Transportation and blending	**1.90**	1.84	1.99	1.94	1.83	1.61	1.10	1.69	2.00	1.71
Operating	**11.89**	11.99	11.83	12.19	11.52	10.78	11.04	9.70	10.72	11.82
Netback	**39.16**	38.61	37.42	34.66	46.08	38.51	44.93	45.31	39.43	21.89
Natural Gas Liquids *($/bbl)*										
Price	**61.00**	63.60	54.43	58.71	67.42	49.08	59.06	49.17	44.65	43.42
Royalties	**1.12**	0.75	1.29	1.16	1.39	0.81	0.96	1.00	0.82	0.46
Netback	**59.88**	62.85	53.14	57.55	66.03	48.27	58.10	48.17	43.83	42.96
Total Liquids *($/bbl)*										
Price	**62.96**	62.75	60.80	59.50	68.85	57.14	64.79	63.85	57.81	39.45
Royalties	**9.33**	9.63	8.96	9.93	8.78	5.62	7.28	6.60	5.14	3.00
Production and mineral taxes	**0.62**	0.59	0.59	0.71	0.59	0.65	0.44	0.63	0.61	0.94
Transportation and blending	**1.88**	1.82	1.97	1.94	1.83	1.60	1.09	1.67	1.98	1.69
Operating	**11.78**	11.84	11.72	12.08	11.42	10.67	10.94	9.61	10.61	11.69
Netback	**39.35**	38.87	37.56	34.84	46.23	38.60	45.04	45.34	39.47	22.13
Total Natural Gas *($/Mcf)*										
Price	**4.09**	3.55	3.68	3.78	5.27	4.15	4.17	3.14	3.80	5.47
Royalties	**0.07**	(0.04)	0.08	0.07	0.14	0.08	0.16	0.02	0.01	0.15
Production and mineral taxes	**0.02**	0.02	0.03	(0.04)	0.07	0.05	0.03	0.04	0.07	0.05
Transportation and blending	**0.17**	0.16	0.15	0.15	0.21	0.15	0.12	0.16	0.16	0.18
Operating	**0.96**	1.02	0.94	0.94	0.94	0.86	0.81	0.84	0.83	0.94
Netback	**2.87**	2.39	2.48	2.66	3.91	3.01	3.05	2.08	2.73	4.15
Total *($/BOE)*										
Price	**44.01**	42.82	41.49	41.46	50.16	39.88	44.54	40.43	38.65	35.71
Royalties	**4.93**	4.90	4.73	5.26	4.81	2.87	4.05	3.22	2.35	1.81
Production and mineral taxes	**0.37**	0.35	0.38	0.24	0.52	0.46	0.30	0.43	0.52	0.58
Transportation and blending	**1.45**	1.40	1.42	1.43	1.53	1.24	0.91	1.29	1.41	1.34
Operating [(6)]	**8.81**	9.08	8.70	8.93	8.53	7.71	7.85	7.24	7.52	8.27
Netback	**28.45**	27.09	26.26	25.60	34.77	27.60	31.43	28.25	26.85	23.71

(1) The Foster Creek 2010 YTD heavy oil price and transportation and blending costs exclude the costs of condensate purchases ($35.43/bbl) which are blended with the heavy oil.
(2) The Christina Lake 2010 YTD heavy oil price and transportation and blending costs exclude the cost of condensate purchases ($36.66/bbl) which are blended with the heavy oil.
(3) The Pelican Lake 2010 YTD heavy oil price and transportation and blending costs exclude the cost of condensate purchases ($14.69/bbl) which are blended with the heavy oil.
(4) The Conventional 2010 YTD heavy oil price and transportation and blending costs exclude the cost of condensate purchases ($11.08/bbl) which are blended with the heavy oil.
(5) The total 2010 YTD heavy oil price and transportation and blending costs exclude the cost of condensate purchases ($26.88/bbl) which are blended with the heavy oil.
(6) 2010 YTD operating costs include costs related to long-term incentives of $0.15/BOE (2009 – $0.09/BOE).

Impact of Realized Financial Hedging

Liquids *($/bbl)*	**(0.36)**	(1.29)	1.01	(0.40)	(0.78)	1.10	(0.05)	(0.01)	1.54	3.29
Natural Gas *($/Mcf)*	**1.07**	1.50	1.09	1.22	0.53	3.63	2.27	4.41	4.33	3.43
Total *($/BOE)*	**2.99**	3.65	3.77	3.37	1.20	12.16	6.92	13.77	14.91	13.06

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

For information in relation to the presentation of our reserves data and other oil and gas information, see the Oil and Gas Reserves and Resources section of our MD&A. We hold significant freehold title rights which generate production for our account from third parties leasing those lands. The Before Royalty volumes presented do not include reserves associated with this Royalty Interest production. The After Royalty volumes presented include our Royalty Interest reserves.

For definitions of the terms used in our oil and gas disclosure, please refer to the Additional Advisory on page 132.

Classifications of reserves as proved or probable are only attempts to define the degree of certainty associated with the estimates. There are numerous uncertainties inherent in estimating quantities of bitumen, oil and natural gas reserves. **It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves.** There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. For additional information on our pricing assumptions, reserves data and other oil and gas information, readers should review "Reserves Data and Other Oil and Gas Information" and "Risk Factors – Uncertainty of Reserves, Resources and Future Net Revenue Estimates", each within our AIF for the year ended December 31, 2010, available at www.sedar.com and at www.cenovus.com.

SUMMARY OF OIL AND GAS RESERVES AT DECEMBER 31, 2010 (FORECAST PRICES AND COSTS)

COMPANY INTEREST BEFORE ROYALTIES [1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	126	111	79	1,292
Developed Non-Producing	20	13	5	62
Undeveloped	1,008	45	27	36
Total Proved Reserves	1,154	169	111	1,390
Probable Reserves	523	97	49	410
Total Proved plus Probable Reserves	1,677	266	160	1,800

Note:
[1] Does not include Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

COMPANY INTEREST AFTER ROYALTIES [1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	96	92	67	1,292
Developed Non-Producing	14	10	4	61
Undeveloped	760	36	21	36
Total Proved Reserves	870	138	92	1,389
Probable Reserves	404	72	39	391
Total Proved plus Probable Reserves	1,274	210	131	1,780

Note:
[1] Includes Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AT DECEMBER 31, 2010 (FORECAST PRICES AND COSTS)

Reserves Category	Before Income Taxes Discounted at %/year ($ millions)					Unit Value Before Income Tax Discounted at 10% (1)
	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	16,118	12,796	10,619	9,102	7,986	22.60
Developed Non-Producing	1,423	888	604	435	325	15.53
Undeveloped	36,936	13,789	6,302	3,300	1,872	7.66
Total Proved Reserves	54,477	27,473	17,525	12,837	10,183	13.16
Probable Reserves	21,163	12,192	6,879	4,031	2,466	11.84
Total Proved plus Probable Reserves	75,640	39,665	24,404	16,868	12,649	12.76

Note:
(1) Unit values have been calculated using the Company Interest After Royalties reserves

Reserves Category	After Income Taxes (1) Discounted at %/year ($ millions)				
	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	12,683	10,153	8,480	7,308	6,443
Developed Non-Producing	1,070	666	454	328	245
Undeveloped	27,637	10,359	4,720	2,442	1,349
Total Proved Reserves	41,390	21,178	13,654	10,078	8,037
Probable Reserves	15,783	9,073	5,076	2,923	1,737
Total Proved plus Probable Reserves	57,173	30,251	18,730	13,001	9,774

Note:
(1) After income tax values are calculated by considering the Company's existing tax pools

The estimates of future net revenue presented do not represent fair market value.

RESERVES RECONCILIATION

The following tables provide a reconciliation of our company interest reserves Before Royalties for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2010, presented using forecast prices and costs. All reserves are located in Canada.

RESERVES RECONCILIATION BY PRINCIPAL PRODUCT TYPE AND RESERVES CATEGORY (FORECAST PRICES AND COSTS)

COMPANY INTEREST PROVED – BEFORE ROYALTIES

	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	866	165	112	1,529
Transition to NI 51-101 Standards [2]	–	(1)	(3)	128
December 31, 2009 (NI 51-101)	866	164	109	1,657
Extensions and Improved Recovery	270	9	11	45
Discoveries	–	–	–	–
Technical Revisions	40	15	1	60
Economic Factors	–	–	–	(18)
Acquisitions	–	–	–	–
Dispositions	–	(5)	–	(87)
Production [3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,154**	**169**	**111**	**1,390**

COMPANY INTEREST PROBABLE – BEFORE ROYALTIES

	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	479	104	53	436
Transition to NI 51-101 Standards [2]	–	(1)	(2)	52
December 31, 2009 (NI 51-101)	479	103	51	488
Extensions and Improved Recovery	132	5	(1)	12
Discoveries	–	–	–	–
Technical Revisions	(88)	(10)	(1)	(82)
Economic Factors	–	–	–	7
Acquisitions	–	–	–	–
Dispositions	–	(1)	–	(15)
Production	–	–	–	–
December 31, 2010	**523**	**97**	**49**	**410**

COMPANY INTEREST PROVED PLUS PROBABLE – BEFORE ROYALTIES

	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	1,345	269	165	1,965
Transition to NI 51-101 Standards [2]	–	(2)	(5)	180
December 31, 2009 (NI 51-101)	1,345	267	160	2,145
Extensions and Improved Recovery	402	14	10	57
Discoveries	–	–	–	–
Technical Revisions	(48)	5	–	(22)
Economic Factors	–	–	–	(11)
Acquisitions	–	–	–	–
Dispositions	–	(6)	–	(102)
Production [3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,677**	**266**	**160**	**1,800**

Notes:

(1) References in the tables to December 31, 2009 (SEC) numbers are to the previously disclosed estimates as of that date prepared by the IQREs in accordance with U.S. disclosure requirements using constant prices and costs as prescribed by the SEC.

(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of Royalty Interest reserves from the Before Royalties reserves totals.

(3) Production used for the reserves reconciliation differs from reported production. Company Interest Before Royalties production for reserves includes Cenovus's share of gas volumes provided to Cenovus's share of the FCCL partnership for steam generation, but does not include royalty interest production, as prescribed by NI 51-101.

ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES

Company Interest Before Royalties, Billions of barrels, Bitumen	**December 31, 2010** [1]	December 31, 2009 [2]
Economic Contingent Resources [3]		
Low Estimate	**4.4**	3.9
Best Estimate	**6.1**	5.4
High Estimate	**8.0**	7.3
Prospective Resources [4]		
Low Estimate	**7.3**	7.8
Best Estimate	**12.3**	12.6
High Estimate	**21.7**	21.4

Notes:

(1) Refers to estimates prepared by McDaniel using the same forecast prices and costs as used in the 2010 reserves estimates, McDaniel January 1, 2011 forecast prices and costs.

(2) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.

(3) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(4) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.

EXPLORATION AND DEVELOPMENT ACTIVITY

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

EXPLORATION WELLS DRILLED

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2010:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	26	26	–	–	1	1	27	27	21	48	27
Total Canada	26	26	–	–	1	1	27	27	21	48	27
2009:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	4	4	–	–	–	–	4	4	8	12	4
Total Canada	4	4	–	–	–	–	4	4	8	12	4
2008:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	1	1	5	3	2	1	8	5	34	42	5
Total Canada	1	1	5	3	2	1	8	5	34	42	5

DEVELOPMENT WELLS DRILLED

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2010:											
Oil Sands	82	47	–	–	–	–	82	47	8	90	47
Conventional	160	154	499	495	–	–	659	649	204	863	649
Total Canada	242	201	499	495	–	–	741	696	212	953	696
2009:											
Oil Sands	50	29	8	8	8	8	66	45	10	76	45
Conventional	102	101	555	502	2	2	659	605	261	920	605
Total Canada	152	130	563	510	10	10	725	650	271	996	650
2008:											
Oil Sands	41	21	13	13	4	4	58	38	41	99	38
Conventional	105	92	1,489	1,372	7	7	1,601	1,471	503	2,104	1,471
Total Canada	146	113	1,502	1,385	11	11	1,659	1,509	544	2,203	1,509

In addition to the disclosure above, we drilled stratigraphic test wells during the year ended December 31, 2010, with Oil Sands having drilled 259 gross wells (178 net wells) and Conventional having drilled 11 gross wells (9 net wells).

In addition to the disclosure above, we drilled service wells during the year ended December 31, 2010, with Oil Sands having drilled 68 gross wells (44 net wells) and Conventional having drilled 30 gross wells (20 net wells).

INTEREST IN MATERIAL PROPERTIES

The following table summarizes our developed, undeveloped and total landholdings at December 31, 2010.

(thousands of acres)	Developed		Undeveloped (1)		Total (2)	
	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown (3)	696	597	1,845	1,455	2,541	2,052
Conventional						
– Fee (4)	1,913	1,913	440	440	2,353	2,353
– Crown (3)	1,571	1,463	372	306	1,943	1,769
– Freehold (5)	51	42	35	32	86	74
Total Alberta	4,231	4,015	2,692	2,233	6,923	6,248
Saskatchewan:						
Conventional						
– Fee (4)	69	69	437	437	506	506
– Crown (3)	47	34	162	141	209	175
– Freehold (5)	13	9	28	25	41	34
Total Saskatchewan	129	112	627	603	756	715
Manitoba:						
Conventional – Fee (4)	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,363	4,130	3,580	3,097	7,943	7,227

Notes:

(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.

(2) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.

(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which we have purchased a working interest lease.

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

(5) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

ADDITIONAL ADVISORY

OIL AND GAS INFORMATION

The following definitions are applicable to our oil and gas disclosure in this Annual Report. For definitions related to our contingent and prospective resources disclosure, see "Oil and Gas Information" in the Advisory section of our MD&A. For additional definitions that are not included here, please see "Reserves Data and Other Oil and Gas Information" within our AIF for the year ended December 31, 2010, available at www.sedar.com and at www.cenovus.com.

After Royalties means volumes after deduction of royalties and including any royalty interests.

Before Royalties means volumes before deduction of royalties and excluding any royalty interests.

Bitumen initially-in-place

> **Discovered bitumen initially-in-place** (56 Bbbls) is the quantity of bitumen estimated, as at December 31, 2009 by an independent qualified reserves evaluator, to be contained in known accumulations prior to production. The recoverable portion of discovered bitumen initially-in-place includes production, reserves, and contingent resources; the remainder is categorized as unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the estimate.
>
> **Total bitumen initially-in-place** (BIIP) (137 Bbbls) is the quantity of bitumen estimated, as at December 31, 2009 by an independent qualified reserves evaluator, to exist originally in naturally occurring accumulations. It includes Discovered BIIP (56 Bbbls) plus Undiscovered BIIP (82 Bbbls) which includes those estimated quantities, as at December 31, 2009, in accumulations yet to be discovered. There is no certainty that any portion of the estimate will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the estimate.

Bitumen initially-in-place estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. For further information regarding these estimates and all subcategories thereof, please see our June 16, 2010 news release, available at www.sedar.com and www.cenovus.com.

Company Interest means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by Cenovus.

Royalty Interest means:

(a) in relation to reserves, those reserves related to our royalty entitlement on lands to which we hold freehold title which have been leased to third parties, or reserves related to other royalty interests, such as overriding royalties to which we are entitled.

(b) in relation to production, the production generated for Cenovus's account pursuant to leasing agreements of our freehold title lands, and other royalty entitlement agreements.

FINDING AND DEVELOPMENT COSTS

Finding and development costs disclosed on pages 25 and 33 of this Annual Report do not include changes in estimated future development costs and exclude the effects of acquisitions and dispositions. Cenovus uses finding and development costs without changes in estimated future development costs as an indicator of relative performance to be consistent with the methodology accepted within the oil and gas industry. Finding and development costs excluding the effects of acquisitions and dispositions and without changes in future development costs is equal to finding and development capital investment divided by finding and development reserves additions. Finding and development reserves additions are calculated by summing revisions, improved recovery, extensions and discoveries.

Finding and development costs for proved reserves, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $10.55/BOE for the year ended December 31, 2010, $16.01/BOE for the year ended December 31, 2009 and averaged $16.95/BOE for the three years ended December 31, 2010. Finding and development costs for proved plus probable reserves, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $9.78/BOE for the year ended December 31, 2010, $81.70/BOE for the year ended December 31, 2009 and averaged $24.43/BOE for the three years ended December 31, 2010. These finding and development costs were calculated by dividing the sum of exploration costs, development costs and changes in future development costs in the particular year by the reserves additions (the sum of discoveries, extensions and improved recovery and technical revisions) in that year. The aggregate of the exploration and development costs incurred in a particular year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

For additional information about our finding and development costs, capital investment and reserves additions, please see our February 18, 2011 news release available at www.sedar.com and www.cenovus.com.

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Corporate Information

EXECUTIVE OFFICERS

Brian C. Ferguson
President & Chief Executive Officer

John K. Brannan
Executive Vice-President &
Chief Operating Officer

Harbir S. Chhina
Executive Vice-President, Oil Sands

Kerry D. Dyte
Executive Vice-President, General
Counsel & Corporate Secretary

Judy A. Fairburn
Executive Vice-President,
Environment & Strategic Planning

Sheila M. McIntosh
Executive Vice-President,
Communications & Stakeholder
Relations

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer

Donald T. Swystun
Executive Vice-President, Refining,
Marketing, Transportation &
Development

Hayward J. Walls
Executive Vice-President,
Organization & Workplace
Development

BOARD OF DIRECTORS

Michael A. Grandin(1)(4)(8)
Chair, Calgary, Alberta

Ralph S. Cunningham(1)(3)(4)(6)
Houston, Texas

Patrick D. Daniel(1)(2)(3)(4)
Calgary, Alberta

Ian W. Delaney(1)(3)(4)(6)
Toronto, Ontario

Brian C. Ferguson(7)
Calgary, Alberta

Valerie A. A. Nielsen(1)(2)(4)(5)
Calgary, Alberta

Charles M. Rampacek(4)(5)(6)
Dallas, Texas

Colin Taylor(2)(3)(4)
Toronto, Ontario

Wayne G. Thomson(1)(4)(5)(6)
Calgary, Alberta

(1) Former director of Encana.
(2) Member of the Audit Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Nominating and Corporate Governance Committee.
(5) Member of the Reserves Committee.
(6) Member of the Safety, Environment and Responsibility Committee.
(7) As an officer and a non-independent director, Mr. Ferguson is not a member of any of the Committees of our Board.
(8) Ex-officio non-voting member of all other Committees of our Board.

CENOVUS HEAD & REGISTERED OFFICE

Cenovus Energy Inc.
421 – 7 Avenue S.W.
PO Box 766
Calgary, Alberta, Canada T2P 0M5
Phone: 403-766-2000
www.cenovus.com

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Shareholder Information

ANNUAL MEETING

Shareholders are invited to attend the annual meeting being held on Wednesday, April 27, 2011 at 2 p.m. (Calgary time) at the TELUS Convention Centre, Exhibition Hall E, 2nd Floor, North Building, 136 – 8 Avenue S.E., Calgary, Alberta.

Please see our management proxy circular mailed to shareholders and posted on our website, www.cenovus.com, for additional information.

TRANSFER AGENTS & REGISTRAR

In Canada, CIBC Mellon Trust Company in Calgary, Montreal & Toronto. In the United States, BNY Mellon in Jersey City, New Jersey.

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached throughout North America by phoning 1-866-332-8898 (English & French) and outside North America by phone at 1-416-643-5850 or by facsimile at 1-416-643-5501.

Canadian Stock Transfer Company
CIBC Mellon Trust Company
PO Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
www.cibcmellon.com

Canadian Stock Transfer Company Inc. recently purchased the Transfer Agency business from CIBC Mellon. Canadian Stock Transfer Company Inc. is operating the Transfer Agency business in the name of CIBC Mellon Trust Company for a transition period.

SHAREHOLDER ACCOUNT MATTERS

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

STOCK EXCHANGES

Common Shares (CVE) trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE).

ANNUAL INFORMATION FORM / FORM 40-F

Our Annual Information Form is filed with the Canadian Securities Administrators in Canada on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as Form 40-F on EDGAR at www.sec.gov.

NYSE STATEMENT OF DIFFERENCES

As a Canadian company listed on the New York Stock Exchange (NYSE), we are not required to comply with most of the NYSE corporate governance standards and instead may comply with Canadian corporate governance requirements. We are, however, required to disclose the significant differences between our corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Except as summarized on our website, www.cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

INVESTOR RELATIONS

Please visit the *Invest In Us* section of www.cenovus.com for investor information.

Investor inquiries should be directed to:

403-766-7711
investor.relations@cenovus.com

or

Susan Grey
Director, Investor Relations
403-766-4751
susan.grey@cenovus.com

Media inquiries should be directed to:

403-766-7751
media.relations@cenovus.com

or

Rhona DelFrari
Manager, Media Relations
403-766-4740
rhona.delfrari@cenovus.com

Designed and produced by Foundry Creative Inc.

Brian Ferguson talks about Cenovus, our operations and how we're doing things differently. Want to see the video? Download a free QR code reader on your mobile browser.

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