CENOVUS ENERGY 2012 ANNUAL REPORT

CENOVUS.COM

We are on track with our strategy. We are on track with our business plan. And we have the bright minds to deliver on our commitments.

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FORWARD-LOOKING INFORMATION This 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. 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 approach to risk management, see "Risk Management" in our Management's Discussion and Analysis for the year ended December 31, 2012 ("MD&A"). NON-GAAP MEASURES This 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 This Annual Report contains information about our reserves and our bitumen resources. For additional information about our reserves, contingent and prospective resources, see "Oil and Gas Reserves and Resources" in our MD&A and "Additional Reserves and Oil and Gas Information" in this Annual Report.

Who we are

We are a Canadian integrated oil company. Our goal is to increase total shareholder return, while applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. We are focused on delivering predictable, reliable performance.

Our achievements are a direct result of the energy of our people. That energy is the momentum that's carrying us forward.

Why investing in Cenovus makes sense

- We have industry-leading oil sands assets. These great assets support decades of oil growth.
- We have a track record of strong operational results. This has allowed us to be a leader in steam-assisted gravity drainage, or SAGD.
- We have a manufacturing approach to oil development. This approach supports our industry-leading cost metrics and capital efficiencies.
- We are focused on innovation. This means we're continually improving our performance.
- We have an integrated approach. This improves the stability of our overall cash flow despite the variability in commodity prices.
- We have financial strength. This provides the flexibility to pursue our growth plans and support a strong and sustainable dividend.

EVOLVING OUR CULTURE

OUR PURPOSE, PROMISE AND VALUES

How we do our work at Cenovus is as important as what we do. Our passion drives us to grow responsibly and live up to our commitments.

Our purpose, our promise and our values are more than just words on a page. They speak to the pride we all have in the work we do and in the way we do it. They speak to the importance of that work to world progress. Most importantly of all, they speak to the kind of company we are. The kind of company we want to be. They guide us in how we do our work today and as we grow.

Our purpose

(WHY WE EXIST)

We inspire bright minds to help fuel world progress.

Our promise

(WHAT WE DO)

We work collectively to unlock challenging oil resources in a way that makes Canadians proud.

Our values

(HOW WE BEHAVE)

Rigorous
We're smart about the way we develop our resources.

We are safety-focused. We manage our business as a whole to get the best results. We understand that executional excellence requires a diversity of talents and perspectives. We can be counted on to do what we say. We are pragmatic and strive to keep things simple. We are responsible and thoughtful in what we do.

Respectful

We trust each other to do the right thing.

We conduct our business with respect, recognizing that respect requires both candour and caring. We collaborate with each other. We make the communities where we live and work better because we are there. We build strong relationships with our stakeholders and business partners. We relentlessly look for ways to reduce the impacts of our activities on the environment.

Ready

We have the courage to embrace fresh thinking and new ideas.

Our innovation today creates the Cenovus of tomorrow. We leverage our decades of operating experience by applying new thinking to our work in a practical, yet creative way. By being ready to continuously improve. By being open-minded problem-solvers. By being decisive and ready for change.

OUR EXECUTIVE TEAM

Left to right

IVOR RUSTE
Executive Vice-President & Chief Financial Officer

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

HAYWARD WALLS
Executive Vice-President, Organization & Workplace Development

HARBIR CHHINA
Executive Vice-President, Oil Sands

BRIAN FERGUSON
President & Chief Executive Officer

JOHN BRANNAN
Executive Vice-President & Chief Operating Officer

SHEILA MCINTOSH
Executive Vice-President, Environment & Corporate Affairs

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

MOTIVATING OUR TEAMS TO GO FURTHER

MESSAGE FROM OUR PRESIDENT & CHIEF EXECUTIVE OFFICER

Attuned to our strategy, culture and people, our leaders inspire great results. Leadership is the propelling force behind any successful business.

BUILDING MOMENTUM

The concept of momentum is a fitting theme for this year's annual report to shareholders. We've been steadily building momentum over our three years as an independent company and I can say with confidence that in 2012 we hit our stride in delivering predictable, reliable performance, and fostering a culture of excellence.

We are on track with our strategy.
We are on track with our business plan.
And, thanks to the smart, dedicated people who work at Cenovus, we once again had strong results.

CREATING VALUE

Our strategy is as simple as it is effective: To create long-term value for you, our shareholders, through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

- Oil sands for growth
- Conventional oil for near-term cash flow and diversification of our revenue stream
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs
- Refining to help reduce the impact of commodity price fluctuations

We are focused on continually building our net asset value (NAV) and paying a strong dividend. Our goal is to double our NAV between 2010 and the end of 2015. We established a baseline illustrative NAV of $28 per share in December 2009 and it has since grown every year. Despite weaker oil and natural gas prices in 2012, we grew NAV to $40 per share at year end, a 43 percent increase in our first three years of operation.

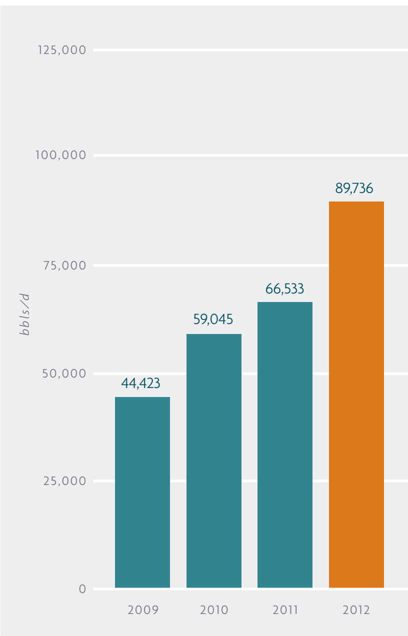
Our growth plan is anchored by the responsible development of our vast oil sands resource base, which includes some of the best in-situ oil sands reservoirs in the industry. We are currently using the most advanced technology to drill into these reservoirs to extract the oil – and are relentless in our pursuit to find even better ways to operate. To improve

our performance. To minimize our environmental impact. To reduce costs. To ensure we work safely.

That's because, at Cenovus, how we do our work is just as important as what we do. To help us define our culture, we formalized a set of statements this past year that outline why we exist as a company (our purpose), what we do (our promise) and how we behave (our values).

These statements, which you may have already seen on page 2, were rolled out to staff at a company-wide forum in November and will guide us as we continue to grow. They were developed with input from the senior leaders of our company and reflect both the fundamental importance of energy in our lives as well as what we believe in as a company.

OIL SANDS PRODUCTION *(before royalties)*



DELIVERING QUALITY RESULTS

We do our utmost to live up to the responsibility that goes with being a developer of one of Canada's most valuable resources. We are proud of how we are developing this resource and stand behind our actions.

It starts with executing with excellence, which is integral to everything we do at Cenovus.

On the oil sands side, our teams worked hard through the year to move the value of our resources forward, continuing to develop them responsibly, on time and at industry-leading costs. At the end of 2012, our oil sands operations had the capacity to produce nearly 110,000 barrels of oil per day net. Our strategic objective is to have, by late 2015, capacity in excess of 600,000 barrels of oil per day net to Cenovus of producing or regulator-approved projects. This will give Cenovus a broad portfolio of investment opportunities and lock in low-risk growth for more than the next decade.

At Christina Lake, average production nearly tripled in 2012 compared with 2011 to about 32,000 barrels of oil per day net as we continued to bring on additional expansion phases ahead of schedule. We are encouraged by the overall well productivity at Christina Lake and are seeing steam-assisted gravity drainage (SAGD) well recovery rates that are among the highest in the industry. With optimization and the addition of another four planned phases, three of which are already under construction, we believe Christina Lake has the potential to produce 300,000 barrels of oil per day gross.

Our Foster Creek operation also continued to demonstrate exceptional performance, with production averaging about 97 percent of current design capacity. Construction of the next three expansion phases at the site is also moving forward. We're on track to reach 310,000 barrels of oil per day gross as we continue to see tremendous value from this reservoir.

As we bring on each new SAGD phase, we are ramping up quickly, using accelerated start-up techniques and enhancing processes where we can. These contribute to increased project returns and to the building of our NAV. In the future, we will continue to look for ways to bring expansion phases on even more efficiently.

But that's not all we're doing to sustain momentum in our business. In 2012, we made excellent progress in developing our emerging oil sands projects.

In May, we received regulatory approval for Narrows Lake – a significant achievement as we move forward with our plan to build NAV. Narrows Lake has a total expected gross capacity of 130,000 barrels of oil per day, with production from the first phase of 45,000 barrels of oil per day expected to start in 2017. Ground work for the initial phase began last fall. I am pleased to report that the project will be one of the world's first commercial applications of an innovative solvent aided process using butane. We are excited about this technology, which has the potential to significantly improve bitumen recovery while continuing to reduce environmental impacts.

We plan to continue to build on this momentum by putting additional projects through the regulatory process. The next two oil sands projects awaiting regulatory approval are Telephone Lake and Grand Rapids – both 100 percent owned by Cenovus. We believe that ultimately

“I am extremely proud to work with the men and women who make up Cenovus. I thank them for the spirit, enthusiasm and energy they have for this company.”

Telephone Lake can support more than 300,000 barrels of oil per day of production capacity and Grand Rapids 180,000 barrels of oil per day of production capacity.

We also continued to develop the potential in our conventional oil operations. At Pelican Lake, heavy oil production volumes have started to increase as a result of the expansion of our polymer flood program, increasing 10 percent from 2011. However, the project has experienced some challenges. We weren't able to achieve production increases as quickly as anticipated as we needed to temporarily reduce reservoir pressure in order to safely drill the infill wells. A new area of opportunity is our emerging tight oil assets in southern Alberta, predominantly our fee land area. We chose to focus capital investment on these conventional oil assets rather than on natural gas and are encouraged by the early results.

All in all, I am extremely pleased with the progress we are making in responsibly growing our production, although an area that we haven't done as well in is safety. Despite the many safety programs we have in place, the number of incidents increased in 2012. That's a huge concern to me, the Executive Team and our Board. We will be increasing our efforts on safety awareness to make sure that safety is top of mind in everything we do for everyone who works at Cenovus.

On a more positive note, as our oil production increases, especially from our oil sands assets, we are seeing notable benefits from our integration strategy. Having a strategy that includes both producing and oil refining operations helps to protect Cenovus from price volatility in the heavy crude oil market. Lower prices for Canadian heavy crude oil decrease our operating cash flow from oil sands production. At the same time, they benefit our refining operating cash flow because it costs less for the feedstock our refineries need to create products such as gasoline and jet fuel.

Our expansion of the heavy oil processing capacity at the Wood River Refinery is providing additional integration since we're able to process more heavy oil at the same time as we're growing our oil production. The expansion effectively doubled our heavy oil processing capacity at Wood River.

In 2012, perhaps more than ever, our refining investments paid off, generating nearly $1.3 billion in operating cash flow and providing significant ongoing support for our company's oil growth plans. Operating cash flow from our refineries would have been even stronger if planned major turnarounds at the Borger and Wood River refineries hadn't gone longer than expected.

As our industry and Cenovus continue to grow production, we expect producers may encounter problems getting oil to various markets if transportation options don't keep pace with growing volumes. In addition to limiting sales points for Canadian oil, this restricted market access drives down the price of Canadian oil relative to U.S. and global prices.

To address these issues, we are taking a portfolio approach to give us a variety of alternatives. We are supporting new pipelines to the U.S. Gulf Coast and Canadian east and west coasts, which open up access to international markets. We are increasing the amount of light and medium oil we ship by rail. And we are entering into hedging arrangements and long-term sales contracts. Through actions such as these as well as the formation of a task force internally, we are working to ensure market access and manage our exposure to price differentials.

Our strong financial position, healthy balance sheet and integration strategy give us the flexibility to withstand volatility while continuing to invest for future growth and maintaining our focus on creating long-term shareholder value.

Certainly our operating and financial results confirm that Cenovus is on the right track. Already in our short history, we have delivered three exceptional years. They are evidence of a company that is consistently executing its strategy to deliver predictable, reliable performance.

In 2012, I'm pleased that we outperformed the S&P/TSX Energy Index by about two percentage points, although we underperformed relative to the broader market, lagging behind the S&P/TSX composite Index by approximately six percentage points. Since the company's formation in late 2009, we have delivered total shareholder return of 35 percent, outperforming the S&P/TSX Energy Index and the S&P/TSX Composite Index by approximately 10 and six percentage points respectively.

This outperformance of both the energy and broader market index in total shareholder return recognizes that we are building the underlying value of the company – as measured by NAV. It also demonstrates we are providing a strong and growing income stream to our shareholders by way of a dividend.

While I am pleased with our progress, I am focused on our future. Success is determined over many years, not just three. So, as good as our performance has been we know we must keep up the momentum by delivering even better performance year over year.

PLANS FOR 2013

We plan to keep our focus on these five areas:

Execution excellence: Safety will be a top priority in 2013. Our strong track record of operating efficiently and responsibly while keeping costs low shows we know what it takes to execute our production goals. We must continue to aim for excellence, growing our oil production significantly in 2013, primarily at Christina Lake. Some of our operating costs have crept upwards this past year, so we will remain focused on cost control across our organization by finding ways to work smarter.

Value creation: We need to keep moving the value of our resources forward. Thanks to our strong balance sheet and cash flow, we plan to maintain capital investment in 2013 at about $3.4 billion. Most of the investment will be made to advance

existing and new oil sands assets and will also go towards our conventional oil assets. Our integrated business plan was a key contributor to our financial success in 2012. Moving forward, we need to do a better job of ensuring the benefits of our integration are understood, so we realize even more value for you, our shareholders.

Innovation: At Cenovus, we firmly believe in doing things better. We take pride in our ability to implement new ideas and new approaches. We have already seen the benefits from a number of initiatives we've implemented, ranging from small incremental improvements to new technologies – technologies that improve our operational performance and reduce our environmental impact. We will continue to invest in innovation in 2013 by advancing the work on the 140 technology development projects we have underway.

Reputation and communication: As we grow our business, it's important that we have strong relationships with the communities where we live and work. We will continue to take an active role through media and stakeholder tours in contributing to public understanding about our business. Through our national advertising campaign, we will also continue to do our part to raise Canadians' understanding of why we are so proud of our energy industry.

Healthy organization: We will have an even greater focus on our culture in 2013. We will reinforce it through meaningful actions taken by our leaders and in conversations with our employees, and ensure it is central to developing our people and enhancing our technical and leadership competencies.

It is my belief that a company's long-term success is dependent on three things: having highly talented, passionate and motivated people, having a strong culture, and having a high-quality asset base. At Cenovus, we have all three. You will see evidence of that in the stories in this report.

I am extremely proud to work with the men and women who make up Cenovus. I thank them for the spirit, enthusiasm and energy they have for this company. I would also like to thank our Board of Directors for their insightful guidance and advice. Together, we are ready to take Cenovus to the next level. I am truly excited about the great opportunities ahead of us.

BRIAN C. FERGUSON
President & Chief Executive Officer

HIGHLIGHTS OF OUR PERFORMANCE IN 2012

- ✓ We grew average oil sands production to about 90,000 barrels of oil per day, up 35 percent over 2011.
- ✓ We generated record cash flow of $3.6 billion, due to increased oil production and higher operating cash flow from our refining business.
- ✓ We increased our proved reserves by 12 percent and our economic bitumen best estimate contingent resources by 17 percent in 2012 compared with 2011.
- ✓ Our strong cash flow, combined with our disciplined capital management, allowed us to fund our growth plans while providing a dividend of $0.88 per share – part of our commitment to our shareholders.

DEVELOPING OUR ASSETS

OUR INTEGRATED APPROACH

Our growth plan is anchored by the responsible development of our vast oil sands resource base.

Our integrated approach provides the foundation for years of energy development. It includes an industry-leading portfolio of oil sands assets, two high-quality refineries, a strong balance sheet, and conventional oil and low-cost natural gas operations that generate substantial operating cash flow.

In the oil sands, we have two producing projects, Foster Creek and Christina Lake, which we are continuing to expand. Our next project is Narrows Lake, where we expect to begin construction in the third quarter of 2013. These three projects are operated by Cenovus in partnership with ConocoPhillips. We also have two emerging projects, Grand Rapids and Telephone Lake, in the pilot stage, both of which are 100 percent owned by us. None of our oil sands projects are mined. We use specialized techniques to drill and pump the oil to the surface.

While the bulk of our future growth is anticipated to be in the oil sands, we also expect significant near-term growth from our other oil assets. We produce heavy oil from our 100 percent owned Pelican Lake operation. We also produce light and medium oil from our tight oil plays in southern Alberta and Saskatchewan. Another important oil project is our enhanced oil recovery operation in Weyburn, Saskatchewan.

As an integrated company, our strong portfolio of oil growth assets is complemented by great refining assets. We have ownership in two refineries in the United States as part of a business arrangement with Phillips 66. Cenovus has a 50 percent interest in the Wood River (Illinois) and Borger (Texas) refineries, which Phillips 66 operates. Our integrated approach provides stability to our overall cash flow stream, especially in times of volatile commodity prices.

In addition, our low-cost natural gas assets in southern Alberta provide strong cash flow to help fund our oil growth, and offset the cost of the natural gas we consume within our oil sands and refining operations.

The oil sands – why they're important to Canada

Energy is as essential to our lives as the food we eat and the water we drink. It heats our homes. It creates electricity. It takes us to work. It delivers our food to the grocery store. And fossil fuels, specifically, are also a building block for the plastic, synthetic and petrochemical products we use as part of our daily routines, like smart phones, computers, furniture and many more.

Global energy demand will increase by a third between 2010 and 2035, according to the International Energy Agency (IEA), an autonomous organization that works to ensure reliable, affordable and clean energy for its 28 member countries. Given this growing demand, all energy sources will play a significant role in meeting world needs.

That includes Canada's oil. Canada has the world's third largest oil reserves: 174 billion barrels of oil, 97 percent of which are in the oil sands. Today, about half the oil from the oil sands is accessed by drilling. But, every year, the amount of oil developed that way is expected to rise.

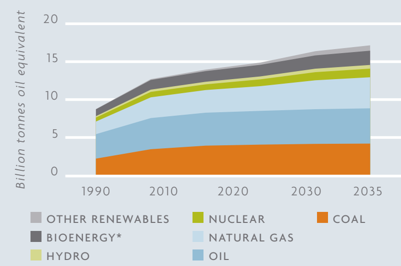
However, it wasn't that long ago that drilling in the oil sands was thought to be impossible because most of the oil is embedded deep underground in sand. Through determination and persistence, some ingenious Canadians figured out that the oil could be separated and liquefied by injecting steam into the well.

In Canada, we're fortunate to have enough oil to take us into the next century and beyond.

In addition to supporting our way of life, the oil from the oil sands generates hundreds of thousands of jobs, and contributes billions of dollars in tax revenue and investment in our economy across Canada every year.

GLOBAL PRIMARY ENERGY DEMAND

Oil sands help supply global energy needs.



*Includes traditional and modern biomass uses

Source: IEA 2012

The oil sands – how we're developing them responsibly

With tremendous accuracy, we drill two horizontal wells, one directly above the other, deep under the ground. We inject steam into the top well to liquefy the oil and separate it from the sand as much as 450 metres below the surface. With the help of gravity, the oil then flows into the bottom well where it's pumped to the surface. This is all done with as little disruption to the land as possible. That's steam-assisted gravity drainage technology, or SAGD as it's called.

In fact, 80 percent of the oil in the oil sands is buried so deep, it can only be accessed by drilling. About 20 percent of the oil in the oil sands is close to the surface and can be mined.

While drilling in the oil sands is still very much in its early stages, we've made some huge advancements to the technology in just a few short years – advancements that have improved both our operational and environmental performance. We spend a significant amount of time learning about our oil sands reservoirs; each is unique and has different characteristics. We also test new ways to improve SAGD technologies and reduce our environmental footprint. It's challenging work, but we are persistent in our determination to continue to build and operate our projects efficiently and improve our performance. We're tackling these challenges every day so we can be even better at what we do.

USING SALTY WATER WHEREVER WE CAN

Most of the water we use to generate the steam we inject underground is saline water. Saline water, because it's salty, can't be used for human or animal consumption, or for watering plants. We get this water from deep underground and recycle it over and over again in our production process. Less than five percent of the water we use in our oil sands operations is fresh. The fresh water comes from underground aquifers not from lakes or rivers.

STRIVING FOR A LOW STEAM TO OIL RATIO

Part of the work that goes into developing our projects is identifying ways to make the steam to oil ratio (SOR) as low as possible.

SOR measures the amount of steam used to produce a barrel of oil from the oil sands. A low SOR is a reflection of the approach used to develop the resource, the efficiency with which we run our facilities and the quality of the reservoir.

Our combined SOR at Christina Lake and Foster Creek in 2012 was 2.1, among the lowest in the industry. A low SOR is not only good for the environment but it's also good for the bottom line because we burn less natural gas and use less water.

CHARTING OUR COURSE

OUR STRATEGY

We have the resource base, the financial strength and the integrated approach that position us well today and for the long term.

Our strategy

We create long-term value for our shareholders through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value (NAV) and paying a strong and sustainable dividend.

Due to the long-term nature of our oil sands projects, and the phased approach we take to develop those projects, our business plan looks out 10 years. It's reviewed regularly to ensure we're able to anticipate and create change when needed, so we're able to be resilient and deliver predictable, reliable results.

While our oil sands resources are the dominant asset in our portfolio, they don't stand alone. Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

- Oil sands for growth
- Conventional oil for near-term cash flow and diversification of our revenue stream
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs
- Refining to help reduce the impact of commodity price fluctuations

We measure our progress by our ability to deliver on the commitments and milestones we set each year and, longer term, by our ability to:

- Meet our 2021 target of producing about 500,000 barrels of oil per day net to Cenovus
- Continually grow our NAV over the long term, with an interim target of achieving a NAV of $56 per share by the end of 2015
- Maintain a solid balance sheet and pay a strong and sustainable dividend

Our milestones

It's important to us that you know our operational milestones and can track our progress as we build our business over many years.

OUR 2012 MILESTONES – WE MET EACH ONE

- ✓ Grow reserves and contingent resources
- ✓ Drill 400 to 500 stratigraphic test wells and assess results
- ✓ Achieve first production at Christina Lake phase D
- ✓ Anticipate regulatory approval for Narrows Lake project and partner approval for phase A – start construction
- ✓ Achieve production growth response from the Pelican Lake expansion
- ✓ Pursue additional conventional oil growth opportunities
- ✓ Connect Shaunavon and Bakken central facilities to pipeline to support tight oil production growth in the area
- ✓ Implement at least one new commercial technology
- ✓ Demonstrate stable and reliable coker and refinery expansion (CORE) operation at the Wood River Refinery
- ✓ Develop tailored business unit environmental performance strategies
- ✓ Advance value creation from Telephone Lake asset

OUR 2013 MILESTONES

- Grow reserves and contingent resources
- Drill 350 to 400 gross stratigraphic test wells and assess results
- Submit regulatory application for Foster Creek phase J expansion
- Submit regulatory application for Christina Lake phase H expansion
- Provide updates on Grand Rapids and Telephone Lake pilot projects
- Achieve first production at Christina Lake phase E in the third quarter
- Increase rail takeaway capacity for oil to approximately 10,000 bbls/d
- Progress preliminary work and initiate facility construction at Narrows Lake phase A
- Anticipate regulatory approval for Grand Rapids in the fourth quarter
- Evaluate debottlenecking opportunities at the Wood River Refinery
- Continue to evaluate light oil opportunities
- Leverage supply chain management to improve operating costs

ADVANCING OUR TOP-QUALITY RESOURCES

LOOKING BACK ON THE YEAR

We're excited about developing energy for generations to come. Our commitment to develop it safely, responsibly and efficiently is what sparks our innovative spirit.

"We rose to the challenge by developing a totally new process for SAGD. It's called dewatering."

– **ROBERT BAILLARGEON**

"This could be the start of a new generation of solvent-based recovery options to enhance the SAGD process, and that's exciting."

– **MIKE PLETTELL**

Unlocking potential at Telephone Lake

Robert Baillargeon, who's part of a team responsible for our new venture activities, is enthusiastic about the future of our Telephone Lake asset.

Robert describes this emerging project as having a unique reservoir with huge potential, anticipating production capacity of more than 300,000 barrels of oil per day. What's unique about the reservoir is that, unlike any of our other oil sands assets, there's a layer of water that sits above the oil deep below the surface. In order for Telephone Lake to be as efficient as our other oil sands projects, we needed to figure out how to remove that layer of water before we produce oil using steam-assisted gravity drainage (SAGD) technology.

"We rose to the challenge by developing a totally new process for SAGD. It's called dewatering and, based on the early results of testing we did in 2012, it's all working as expected, so we're off to a good start," says Robert.

By removing the water we expect SAGD to work more efficiently in this reservoir, allowing us to reduce the steam to oil ratio (SOR) and operating costs for the project. SOR is the amount of steam it takes to produce a barrel of oil.

To learn more about the dewatering process, including what we do with the water we remove, visit cenovus.com.

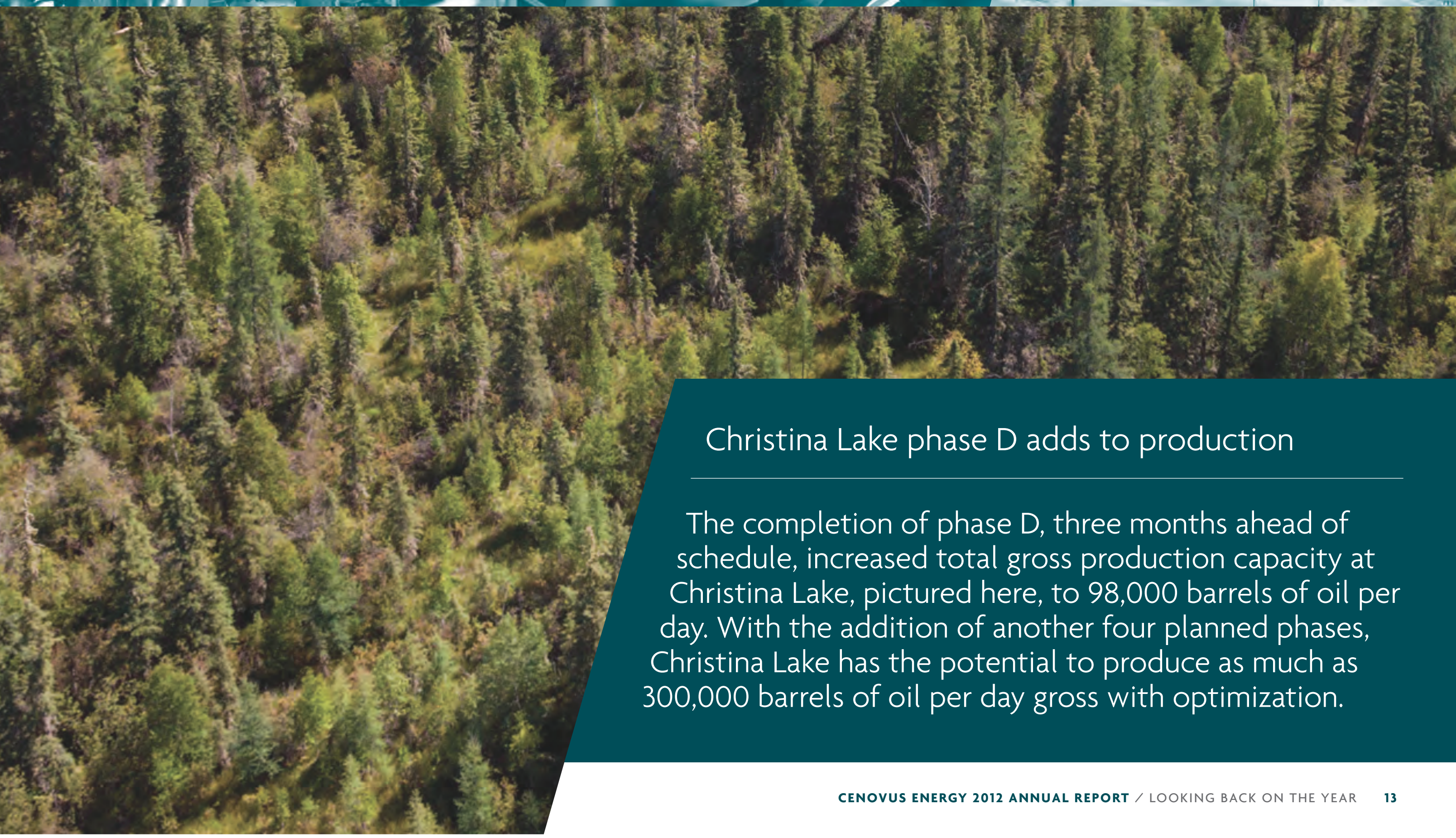
Excitement builds for Narrows Lake

As a company, we're excited about our Narrows Lake oil sands project because it's the first we'll have built from the ground up in over a decade.

The approved project, which is our third in the oil sands, will be developed in three phases and is anticipated to have a gross production capacity of 130,000 barrels of oil per day, playing a significant part in our growth plans. Site preparation is underway and we expect to complete the first phase in 2017. It will be the first time butane is used as a solvent with steam on a commercial scale. Until now, we've used only steam to liquefy the oil to the point where it can be pumped to the surface.

"This could be the start of a new generation of solvent-based recovery options to enhance the SAGD process, and that's exciting," says Mike Plettell, a development planner on the project.

The official term for adding a solvent is solvent aided process, or SAP. In this case, it involves injecting both steam and butane, a naturally-occurring natural gas liquid. The butane dissolves into the oil making it thinner and allowing it to flow more freely to the producing well. Using a solvent like butane in our SAGD process reduces the amount of steam we use to recover each barrel of oil. Based on results of testing at Christina Lake, SAP has the potential to decrease the SOR and improve the oil production rate by as much as 30 percent when compared with SAGD alone.



Christina Lake phase D adds to production

The completion of phase D, three months ahead of schedule, increased total gross production capacity at Christina Lake, pictured here, to 98,000 barrels of oil per day. With the addition of another four planned phases, Christina Lake has the potential to produce as much as 300,000 barrels of oil per day gross with optimization.

SHIFTING GEARS

Being flexible in business means being able to adapt and thrive in times of change. Some of our teams from our conventional oil and natural gas properties have proven to be very capable of doing just that. With our growth strategy focused on oil, and because of stronger oil prices relative to natural gas, the teams safely and successfully transitioned from producing natural gas to producing more oil in 2012 compared to 2011. Our ability to shift gears is, in part, why we exceeded production targets for oil in Alberta. And we still produced 594 million cubic feet per day of natural gas, continuing to provide significant ongoing financial support for our oil growth plans.

"Being able to shift our focus while maintaining our strong team coordination and attention to safety were key to our success. I'm so proud of everyone involved," says Dan Schiller, Senior Vice-President, Conventional Oil & Natural Gas.

FINANCIAL STRENGTH CONTINUES TO SUPPORT GROWTH

We have high-quality assets, a strong growth plan and the right people to execute on our strategy. Part of executing our strategy is about maintaining our solid financial position to help support our growth.

In 2012, we increased the capacity of our commercial paper program, extended the term of our committed credit facility and issued US$1.25 billion of senior unsecured notes at attractive long-term rates.

"These steps further improved our liquidity and financial strength to carry out our future plans," says Shane Cooke, Assistant Treasurer.

SPENDING LOCALLY HELPS US MEET LABOUR NEEDS AND CONTRIBUTES TO THE LOCAL ECONOMY

Many of our operations are located in remote and rural areas of Alberta and Saskatchewan. Hiring local businesses and sourcing local contract services, including Aboriginal businesses, is a key part of how

Part of executing our strategy is about maintaining our solid financial position to help support our growth.

we do business. In 2012, we spent over $1 billion doing business with local and Aboriginal companies in our operating areas, doubling our spend since 2010.

"Not only does this help us with our growth plans, it also benefits the communities where we operate," says Troy Schwab, who is responsible for business development in our local communities. "By taking this approach we know there will be a number of qualified companies that understand our business and have as much interest in our success as their own."

HEARING FROM OUR STAKEHOLDERS

Our commitment to doing right by the environment and the communities where we live and work is something we take very seriously.

We seek feedback from those living in our operating areas and from large urban centres across Canada on a regular basis. We do that through focus groups, and telephone and online surveys.

The 2012 telephone survey that we commissioned in our Alberta and Saskatchewan operating areas indicates that we are demonstrating that commitment:

- 93 percent of respondents said Cenovus works hard to minimize its impact on the environment
- 95 percent said Cenovus provides benefits to their community
- 95 percent said Cenovus conducts business in an honest, ethical manner

"Knowing what's important to people when it comes to oil development helps us get better at what we do," says Sandra Barker, a manager on our Communications team.

DRIVING VALUE THROUGH EXECUTION

LOOKING BACK ON THE YEAR

Executing with excellence is integral to everything we do. It's what motivates our teams to consistently deliver great results.

"It's a great time to be in the refining business. Our integration strategy is really paying off for Cenovus overall."

– PETER LANDRY

"When you look at our daily production plot, you'll see a steady line ... To me, that's excellent performance."

– RANDY PENNY

Our integration strategy generates strong performance

Not only do we produce oil in the oil sands, we also own 50 percent of two U.S. refineries. Phillips 66 owns the other half and is the operator.

Our ownership in these refineries means we can capture the full value chain from oil production through to refined products. Once the oil is out of the ground, it has to go through a number of steps – blending, transporting, upgrading, refining – all the way to finished products such as gasoline, diesel and jet fuel. From a pricing perspective, the value of a barrel of heavy crude oil is significantly less than the value of a comparable amount of gasoline or jet fuel.

"It's a great time to be in the refining business. Our integration strategy is really paying off for Cenovus overall," says Peter Landry, who works as a business planner on our refining team.

Having both upstream and downstream operations helps protect us from price variability in the heavy crude oil market. Being involved in various steps of the value chain helps our bottom line by allowing us to capture value from the production of oil through to the output of finished products like transportation fuels. Essentially, we shift from being a producer of heavy crude oil to being a producer of high-value finished products.

Operations excellence drives Foster Creek's production results

When Randy Penny, our Vice-President of Foster Creek Operations, talks about operating performance at Foster Creek over the last year, he uses a production graph to make his point.

"When you look at our daily production plot, you'll see a steady line with no significant day-to-day variations. That's what you want to see because it means we're delivering consistent production," says Randy. "To me, that's excellent performance."

Foster Creek production averaged approximately 116,000 barrels of oil per day gross in 2012. In fact, we exceeded nameplate capacity, which is 120,000 barrels of oil per day gross, for six months of the year. This means we produced more oil per day than we had anticipated at this stage of the project.

Randy says the facility's success is largely due to a program we call Operations Excellence, which has introduced systems and techniques aimed at helping us continuously improve our performance.

Our Wood River and Borger refineries

Strategically located in the mid-continent of the United States, these refineries are able to process heavy oil, which has helped generate strong operating cash flow.

> "It's everyone's responsibility on site to be safe by looking after ourselves and one another."
> – **SHELDON JACKSON**

LIVING UP TO OUR COMMITMENT TO MAKING COMMUNITIES BETTER

For Liz Swift, who works on one of our environment teams, giving back to her community is more than just giving money to a charity. And she should know. Every year, Liz gives time and money to a cause that's close to her heart.

"Several of my family members have been affected by multiple sclerosis (MS) and a large part of my effort is dedicated to helping end MS," says Liz. "It's great to work for a company that encourages employees to volunteer. Not only does MS get some of my time, I'm also able to submit my volunteer hours to receive a company grant that goes to MS."

Liz is one of 1,194 employees who, in total, donated over $1.7 million to 864 charities through our employee giving programs, one of which is called Thanks & Giving. That amount was matched dollar for dollar by Cenovus, making a combined total of approximately $3.5 million for 2012. She's also one of our many employees who volunteered at 64 company-sponsored events.

Cenovus also contributed more than $10 million to more than 435 charities. As an Imagine Canada Caring Company we give one percent of our pre-tax profits to charitable or non-profit organizations. It's all part of our commitment to making communities where we live and work stronger and better off as a result of us being there.

WALKING THE TALK GETS US RECOGNIZED

The Dow Jones Sustainability World Index is an exclusive list of the world's best corporate citizens and we're on it. We were the only Canadian oil and gas company to make the 2012-2013 index and one of just 11 Canadian companies. We were also named to the Dow Jones Sustainability Index (DJSI) North America for the third year in a row.

In Canada, we were listed as one of the 2012 Best 50 Corporate Citizens by *Corporate Knights* magazine, included on the 2012 Carbon Disclosure Leadership Index for the third time and recognized as one of the most trusted and respected brands by *Canadian Business* magazine.

"Making it on these lists tells me that others believe we're walking the talk," says Craig Stenhouse, who leads our Corporate Responsibility team.

THINKING SAFE MARKS FOUR YEARS OF NO LOST-TIME INCIDENTS AT PELICAN LAKE

When a contractor was disconnecting a process line at Pelican Lake he noticed two others enter the area who weren't wearing all the required safety gear for the work

being done. He immediately stopped the work and ensured they exited to a safe area before continuing his work.

"It's everyone's responsibility on site to be safe by looking after ourselves and one another," says Sheldon Jackson, an operator who saw what happened. "The fact that the work was stopped to address a potential safety risk, tells me we're living up to our safety commitments."

This is just one example of how the Pelican Lake team has achieved four years of no lost-time safety incidents and of the importance Cenovus places on safety.

HOW MOVING A HERD OF CATTLE STRENGTHENED A RELATIONSHIP

Moving a herd of cattle from one pasture to another using a municipal roadway takes more than just a few people on horseback. That's why a local landowner made sure he contacted our Weyburn facility ahead of time to lessen any impact the move would have on our business.

"When I got the notice from our landowner, I sent a note to all our staff to make sure everyone knew and would exercise caution when coming across the herd on the road," says Arron Rush, an operator at the facility. "The landowner let us know how pleased he was with the respect and cooperation he received from us. It made me feel great knowing that doing the right thing goes a long way."

We want community members to know they can expect respect in everything we do. Our Expect Respect program, launched in 2012, also addresses concerns often associated with oil and gas operations such as noise and dust. It's one of the ways we demonstrate to our neighbours that we're operating responsibly.

ON THE MOVE

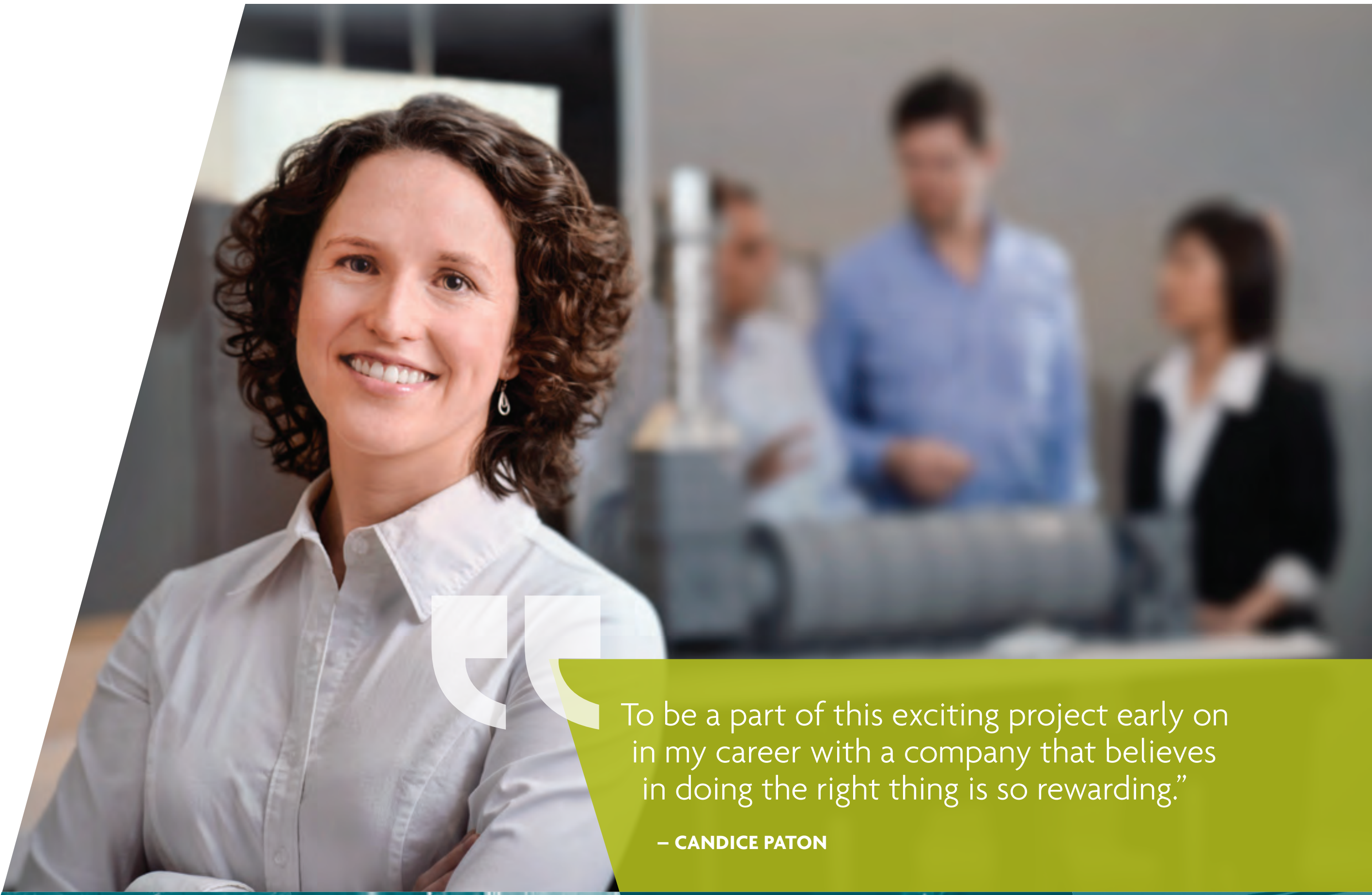
Several years of hard work by hundreds of people from across the company made it possible for more than 2,500 employees to move into four buildings in 2012, including our head office move to THE BOW, with minimal disruption to their daily work.

"Feedback from employees was that the move was seamless – they simply packed their old office at the end of one week and showed up on Monday to their new office ready to work," says Denise Froese, Vice-President, Administrative Services. "Our success in this transition is a reflection of the tireless efforts of so many people and the strength of teamwork and collaboration to execute a strong plan."

APPLYING NEW IDEAS AND NEW APPROACHES

LOOKING BACK ON THE YEAR

While we're proud of our work in the oil sands, we're committed to finding new and better ways to develop this energy resource.



"To be a part of this exciting project early on in my career with a company that believes in doing the right thing is so rewarding."

– CANDICE PATON

"It was great being part of a team that took an idea from whiteboard to reality."

– DUSTIN JACK

Thinking outside the box leads to environmental benefits

What does the automotive industry have in common with the oil sands? If you're thinking gasoline, that's true. But there's also a technology commonly used in the automobile and other industries that we've tailored for our own needs.

Empowered to always improve, a team of our engineers looked outside our industry for ways to reduce our emissions beyond what's required by the regulators. The team introduced a technology called flue gas recirculation that recycles exhaust from steam generators used in the steam-assisted gravity drainage (SAGD) process, just like exhaust is recycled in our cars.

"We're the first in the oil sands to use this technology in the SAGD process and the results we're seeing are cutting emissions significantly," says Candice Paton, one of our technology development engineers. "To be a part of this exciting project early on in my career with a company that believes in doing the right thing is so rewarding."

The technology reduces the amount of nitrogen oxides emitted into the air during the combustion of fuel and gas. In the oil sands we use natural gas in our steam generators. By using a tube to take exhaust from the steam generator, we can recycle the exhaust back into the burner. The exhaust helps cool the burner flame, reducing nitrogen oxide emissions going into the air. Early results show these emissions from the boiler are down to 20 parts per million (ppm) from 40 ppm – a 50 percent reduction. The pilot project is in operation on one boiler at Christina Lake and is expected to be in operation on additional boilers for the next expansion phase.

From the whiteboard to reality: a game-changing innovation

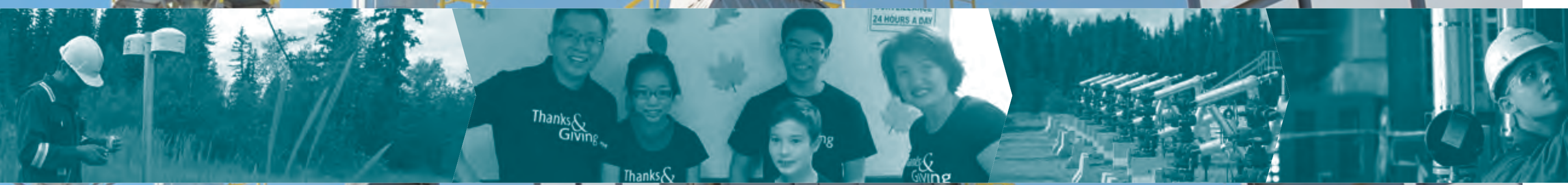
Imagine using a helicopter to place a drilling rig in a remote area. That's what we've started doing in the oil sands to drill stratigraphic test wells that provide information about what's underground.

"Heli-portable drilling rigs have been used for decades in the hard-rock mining industry," says Dustin Jack, one of our drilling technologists. "Our team believed it could also work in the oil sands to solve our challenge of finding a way to drill year-round while reducing our environmental footprint."

After two years of development and testing we put our SkyStrat™ drilling rig into action, drilling a total of 15 wells in 2012. Using this rig eliminates the need for road infrastructure because the rig and crew are transported by helicopter, reducing the amount of land we use. Where we use our SkyStrat™ drilling rig we expect to achieve up to a 50 percent reduction in our surface footprint compared with traditional stratigraphic test well drilling methods.

"It was great being part of a team that took an idea from whiteboard to reality," says Dustin. "And it's great to work for a company whose direct supervisors and senior leaders give us the support we need to be innovative and be able to execute on our ideas."

Our SkyStrat™ drilling rig is also expected to reduce the amount of water we use for drilling operations by up to 50 percent.



Foster Creek, an industry first

Foster Creek, pictured here, is recognized as being the first commercial SAGD project in Alberta. We've introduced a number of innovations at this project, including our Wedge Well™ technology which has increased production by 10 to 15 percent.

Visit cenovus.com for more information.

FOCUSING ON TECHNOLOGY BRINGS REWARDS

We received double honours at *New Technology Magazine's* Technology Star Awards. Our blowdown boiler technology was selected as the best health, safety and environment technology for its innovative approach to water recycling. And, our accelerated start-up with steam technology was selected as runner-up for best production technology.

"The blowdown boiler is a great example of how innovation and efficiency can help us limit our environmental impact," says Susan Sun, who's a water treatment engineer. The blowdown boiler technology has been implemented at Foster Creek and Christina Lake. The enhanced steam generation process allows us to recycle more water and use less natural gas while creating steam for SAGD projects. We expect to introduce this technology at future oil sands projects.

Accelerated start-up, the technology we commercialized in 2012, involves injecting steam down both the injector and producer wells in a controlled manner, to accelerate the interaction between the wells and increase mobility of the oil in the reservoir. This is one of the reasons why Christina Lake was able to achieve first production on phase D earlier than expected.

"Our accelerated start-up with steam dilation is one way we're getting oil out of the ground faster," says Maliha Zaman, one of our reservoir engineers.

COLLABORATION IS KEY TO EARLY START-UP AT CHRISTINA LAKE PHASE D

When our phase D expansion at Christina Lake began producing oil three months ahead of schedule, our operations superintendent, Darren Matvichuk, summed up the achievement in one word: collaboration.

"Our employees came together as a team to achieve this milestone. Collaboration is what strengthens our ability to execute," says

Darren. "We're always looking to challenge the status quo and improve the way we work. In this case we clarified roles and responsibilities, streamlined our processes, and integrated our planning and scheduling."

COSIA: DRAWING UPON THE BEST AND BRIGHTEST

Cenovus was one of the Canadian oil sands producers who in early 2012 joined together to form Canada's Oil Sands Innovation Alliance (COSIA). This new organization is focused on accelerating oil sands environmental performance through innovation and collaboration.

"COSIA is drawing upon the best minds within the industry to develop and implement practical solutions to environmental challenges," says Brian Ferguson, our President & Chief Executive Officer. "As a company, we believe in continuously improving, and we are excited to be a charter member."

COMMUNITY SPIRIT SHINING BRIGHTLY

There's something special about every community. That's why we launched the Great Communities contest, to celebrate the spirit that lives within the communities where we live and work. We asked residents to tell us why their communities are great in 50 words or less.

"I'm inspired by how passionate people are about their communities," says Dave Hassan, who leads the environment technology investment team and was one of the contest judges. "It's wonderful to see such strong community spirit."

In total there were 124 entries. Each of the 12 community residents who submitted winning entries received a $5,000 donation from Cenovus to give to their favourite local charity.

BUILDING MOMENTUM

MESSAGE FROM OUR BOARD CHAIR

The theme of Cenovus's 2012 annual report is building momentum, driving forward. From an operating perspective the company is certainly growing assets and asset value. From a governance perspective the question is whether that momentum can be expected to deliver desirable results. Because the company is "driving," in a responsible manner, toward goals valued by shareholders, your Board believes the answer to be an unequivocal "yes."

Cenovus began independent life in December 2009 with a large inventory of high quality, well understood assets. Since then the company has increased oil reserves and resources each year, increased oil production and sales volumes each year and accelerated schedules for many of its projects based on achieved results. Supported by its comprehensive stratigraphic test well program, Cenovus continues to convert its bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. Downstream integration has paid off with increased cash flow for investment when realized crude prices have been low. Good financial performance supported dividend increases. So, there is no question that momentum is building.

What about direction? An initial dividend and a dividend policy were announced after the company began independent operations. The 2012 dividend increase and the recently announced first quarter 2013 increase were consistent with that policy. A growth plan was laid out in early 2010. Subsequent operating results combined with independent third-party estimates of bitumen initially-in-place and economic contingent resources provided the basis for converting it to an achievable 10-year business plan. The disclosed increase in targeted bitumen production is consistent with that plan. Management adopted net asset value as a performance measure with a target of doubling it by the end of 2015. We believe all of these actions are aimed at goals valued by investors and demonstrate that Cenovus is doing what it said it would do.

All of this progress has been accomplished in a responsible manner, consistent with Cenovus's stated values. The company's financial structure is designed to support growth and absorb significant downside commodity price shock. Downstream integration has mitigated some of the crude oil price risk. The company continues to invest in energy and environmental technology to improve performance and reduce its environmental footprint. Cenovus published its first corporate responsibility report in 2010. The report is based on the company's Corporate Responsibility

Policy and provides a baseline against which performance may be measured. Cenovus has been recognized in each year as a leader in emissions reporting and has been on the Dow Jones Sustainability Index North America for three years, being named to the World Index in 2012.

For these and the many other reasons, described in the company's public documents, your Board believes that Cenovus is definitely building momentum toward goals that will serve investors and all other stakeholders well.

Respectfully submitted on behalf of the Board.

MICHAEL A. GRANDIN
Board Chair

OPERATING HIGHLIGHTS

Before royalties	**2012**	2011	% Change
Production			
Crude Oil and Natural Gas Liquids (bbls/d)			
Oil Sands – Heavy Oil			
Foster Creek	**57,833**	54,868	5
Christina Lake	**31,903**	11,665	173
Total	**89,736**	66,533	35
Pelican Lake	**22,552**	20,424	10
	112,288	86,957	29
Conventional Liquids			
Heavy Oil	**16,015**	15,657	2
Light and Medium Oil	**36,071**	30,524	18
Natural Gas Liquids	**1,029**	1,101	(7)
Total Crude Oil and Natural Gas Liquids (bbls/d)	**165,403**	134,239	23
Natural Gas (MMcf/d)	**594**	656	(9)
Refinery Operations [1]			
Crude Oil Capacity (Mbbls/d)	**452**	452	–
Crude Oil Runs (Mbbls/d)	**412**	401	3
Crude Utilization (%)	**91**	89	2
Proved Reserves [2]			
Total Reserves (MMBOE)	**2,175**	1,945	12
Year-end Bitumen Reserves (MMbbls)	**1,717**	1,455	18
Total Production Replacement (%)	**345**	422	(18)
Recycle Ratio [3]	**3.2**	5.3	(40)
Proved Finding & Development Costs ($/BOE) [4]	**9.04**	5.95	52
Reserve Life Index (years)	**23**	22	5

[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.

[3] Recycle ratio is calculated by dividing netback (before hedging and general and administrative costs) by Proved Finding and Development Costs (excluding changes in future development costs).

[4] Finding and Development Costs presented do not include changes in future development costs. Finding and Development Costs calculated with changes in future development costs for proved reserves and for proved plus probable reserves, are disclosed in the Advisory.

FINANCIAL HIGHLIGHTS

$ Millions, except per share and other amounts as noted	**2012**	2011	% Change
Gross Sales	**17,229**	16,185	6
Revenues	**16,842**	15,696	7
Cash Flow [1]	**3,643**	3,276	11
Per Share – Diluted	**4.80**	4.32	
Operating Earnings [1]	**866**	1,239	(30)
Per Share – Diluted	**1.14**	1.64	
Net Earnings	**993**	1,478	(33)
Per Share – Diluted	**1.31**	1.95	
Capital Investment	**3,368**	2,723	24
Net Acquisition and Divestiture Activity	**38**	(102)	
Net Capital Investment	**3,406**	2,621	30
Dividends Per Common Share	**0.88**	0.80	10
Dividend Yield (%) [2]	**2.6**	2.4	
Debt to Capitalization (%) [1]	**32**	27	
Debt to Adjusted EBITDA (times) [1]	**1.1**	1.0	

[1] Non-GAAP measures as referenced in the Advisory section.

[2] Based on TSX closing share price at year end.

"We had another strong year in 2012, achieving the milestones we set for ourselves. We added significant new reserves and resources, increased our oil production, enhanced net asset value and generated record cash flow. We remain committed to delivering a growing total shareholder return and have again increased our dividend by 10 percent."

– BRIAN FERGUSON, PRESIDENT & CHIEF EXECUTIVE OFFICER

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2012

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "Cenovus", or the "Company") dated February 13, 2013, should be read in conjunction with our December 31, 2012 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated and have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as operating cash flow, cash flow, operating earnings, free cash flow, debt, capitalization and adjusted EBITDA, 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 order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian, integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2012, we had a market capitalization of approximately $25 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our total 2012 average crude oil and NGLs production was in excess of 165,000 barrels per day, our average natural gas production was in excess of 590 MMcf per day and our refinery operations produced approximately 433,000 barrels per day of refined product. Our reportable segments are: Oil Sands, Conventional, Refining and Marketing and Corporate and Eliminations.

OUR STRATEGY

Our strategy is to create long-term value for our shareholders through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

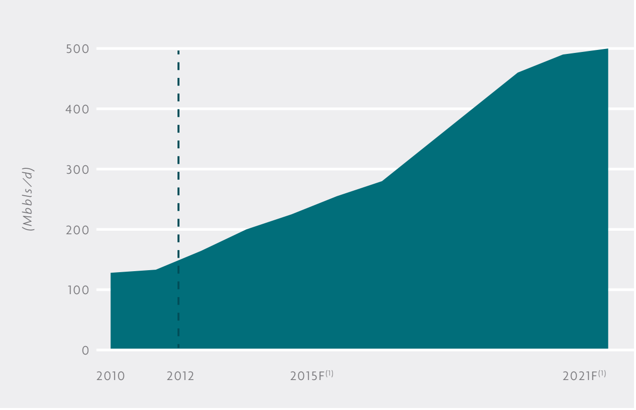
- Oil Sands for growth;
- Conventional crude oil for near-term cash flow and diversification of revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to 400,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 500,000 barrels per day by the end of 2021. We are focusing on the development of our substantial crude oil resources predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows Lake and our tight oil opportunities in Alberta and Saskatchewan. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 350-450 gross stratigraphic test wells each year for the next five years.

TOTAL OIL PRODUCTION (MBBLS/D) NET TO CENOVUS



(1) Expected gross production capacity.

OIL SANDS

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Ownership Interest *(percent)*	2012 Net Production Volumes *(bbls/d)*	Current Expected Gross Production Capacity *(bbls/d)*
Existing Projects			
Foster Creek	**50**	**57,833**	**310,000**
Christina Lake	**50**	**31,903**	**300,000**
Narrows Lake	**50**	**–**	**130,000**
Emerging Plays			
Grand Rapids	**100**	**–**	**180,000**
Telephone Lake	**100**	**–**	**300,000**

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca Region of northeast Alberta. In addition to current production, expansion work is underway at phases F, G and H at Foster Creek with added production capacity expected in 2014. In the third quarter of 2013, Christina Lake is anticipating production from phase E. For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval in December 2012 for phase A. Site preparation is underway and we anticipate first production in 2017.

Two of our emerging projects are Grand Rapids and Telephone Lake. At our Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and Environmental Impact Assessment ("EIA") for a commercial SAGD operation. We anticipate regulatory approval in the fourth quarter of 2013. Our Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA due to an increase in the project development area which we anticipate receiving regulatory approval in 2014.

Also located within the Athabasca Region is our wholly owned Pelican Lake property. Pelican Lake produces heavy oil using polymer flood technology and has expected production capacity of 55,000 barrels per day.

CONVENTIONAL

Our crude oil and NGLs production from our Conventional business segment continues to generate predictable near-term cash flows, which enables further development of our Oil Sands assets and provides diversification to our revenue stream. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations and provides cash flows to help fund our growth opportunities.

For the Year Ended December 31, 2012 ($ millions)	Crude Oil and NGLs	Natural Gas
Operating Cash Flow	**962**	**482**
Capital Investment	**805**	**43**
Operating Cash Flow in Excess of Related Capital Investment	**157**	**439**

We have established conventional crude oil and natural gas producing assets and developing tight oil assets. In Saskatchewan, we also inject carbon dioxide to enhance oil recovery at our Weyburn operations.

Refining and Marketing

Our operations include refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company:

	Ownership Interest *(percent)*	2012 Nameplate Capacity *(Mbbls/d)*
Wood River [(1)]	**50**	**306**
Borger	**50**	**146**

(1) Effective January 1, 2013, Wood River has a nameplate capacity of 311,000 barrels per day.

Our refining operations allow us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel to mitigate volatility associated with North American commodity price movements. This segment also includes the marketing of 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 *(continued)*

($ millions)	**2012**
Operating Cash Flow	**1,267**
Capital Investment	**118**
Operating Cash Flow in Excess of Related Capital Investment	**1,149**

Technology and Environment

Technology development plays a key role in improving the amount of bitumen we can access and extract from the ground, potentially reducing costs and building on our history of excellent project execution. The Cenovus culture fosters new ideas and new approaches and has a track record of developing innovative solutions that unlock previously inaccessible resources. Environmental considerations are embedded into our business with the objective of reducing our environmental impact. We are advancing technologies with the goal of reducing the amount of water, natural gas and electricity consumed in our operations and minimizing surface land disturbance.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return.

Net Asset Value

We measure our success in a number of ways with a key measure being growth in net asset value. Our operational and financial performance in 2012 and consistent production growth has increased our net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

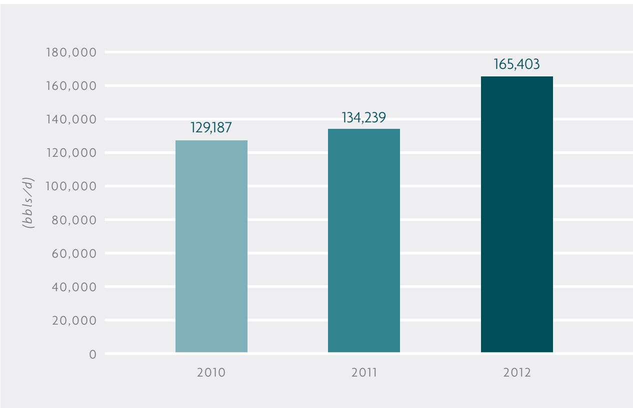
2012 OPERATING AND FINANCIAL HIGHLIGHTS

In 2012, we delivered solid performance and achieved or exceeded the milestones we set out for the year. We completed our planned capital programs, met or exceeded our production targets and increased our net asset value.

OPERATIONAL RESULTS

Crude oil production from our Oil Sands segment averaged 112,288 barrels per day, an increase of 29 percent, primarily due to increased production at Christina Lake and Foster Creek. Christina Lake phase D, our 9th SAGD expansion phase to come online, came on production ahead of schedule in late July, 2012 and below budgeted cost. This was the result of effective use of our Nisku module yard, faster ramp-up of production from improved start-up techniques and production commencing in a higher quality area of the reservoir. Christina Lake set a new single day gross production high of almost 94,000 barrels per day in 2012 and has exceeded gross nameplate capacity of 98,000 barrels per day in early 2013.

TOTAL CRUDE OIL AND NGLS PRODUCTION VOLUMES



Within our Conventional segment, crude oil and NGLs production averaged 53,115 barrels per day, an increase of 12 percent, as a result of our successful drilling programs. Alberta production increased 10 percent to an average of 30,357 barrels per day and Saskatchewan production increased 15 percent to an average of 22,758 barrels per day.

Our proved bitumen reserves increased 18 percent to over 1.7 billion barrels and our economic bitumen best estimate contingent resources increased 17 percent to 9.6 billion barrels, demonstrating our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Our refining operations produced approximately 433,000 barrels per day of refined products, an increase of about 14,000 barrels per day. The increase resulted from greater heavy crude oil processing capability as a result of a full year of operations from the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery which was completed in the fourth quarter of 2011. Refining operations processed an average of 412,000 (2011 – 401,000) barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, despite planned turnarounds at both refineries in the fourth quarter of 2012.

Other significant operational results in 2012, as compared to 2011, include:

- Christina Lake production averaging 31,903 barrels per day, more than doubling, due to the start-up of phases C and D in the third quarters of 2011 and 2012, respectively;
- Foster Creek production averaging 57,833 barrels per day, an increase of five percent due to plant optimization;
- Pelican Lake production averaging 22,552 barrels per day, an increase of 10 percent as a result of our infill drilling and polymer flood programs;

- Natural gas production declining nine percent to an average of 594 MMcf per day, primarily due to expected natural declines and the divestiture of a non-core property early in the first quarter of 2012;
- Receiving regulatory approval for phases A, B and C, and partner approval for phase A of our Narrows Lake project;
- Completing planned refinery turnarounds at both Borger and Wood River; and
- Accessing new markets for our crude oil through pipeline to the west coast and rail to the east coast and U.S.

FINANCIAL RESULTS

Throughout 2012, our financial results benefited from strong crude oil production and continued high refining margins, despite declines in crude oil, NGLs and natural gas prices. Total operating cash flow reached $4.4 billion (an increase of 15 percent) and cash flow was $3.6 billion (an increase of 11 percent). Operating earnings were $866 million (a decrease of 30 percent) primarily due to a goodwill impairment in the fourth quarter related to our Suffield area within our Conventional segment. Net earnings declined 33 percent to $993 million, primarily resulting from non-cash items related to decreases in gains recorded on unrealized risk management activities and divestitures. We completed a US$1.25 billion public offering of senior unsecured notes in August and paid annual dividends of $0.88 per share (2011 – $0.80 per share).

Other financial highlights for 2012, as compared to 2011, include:

Revenues

Revenues of $16,842 million, increasing $1,146 million or seven percent as a result of:

- Crude oil and NGLs sales volumes increasing 25 percent;
- Refining and Marketing revenues rising $731 million due primarily to higher refinery output and refined product prices; and
- A decrease in crude oil and NGLs royalties by 20 percent primarily due to an increase in capital investment.

Partially offsetting these increases in revenues were:

- Our crude oil and NGLs average sales prices (excluding financial hedging) decreasing 10 percent; and
- Natural gas revenues decreasing $344 million due to declining production and lower average sales prices.

Operating Cash Flow

Operating cash flow of $4,436 million, increasing $574 million or 15 percent due to:

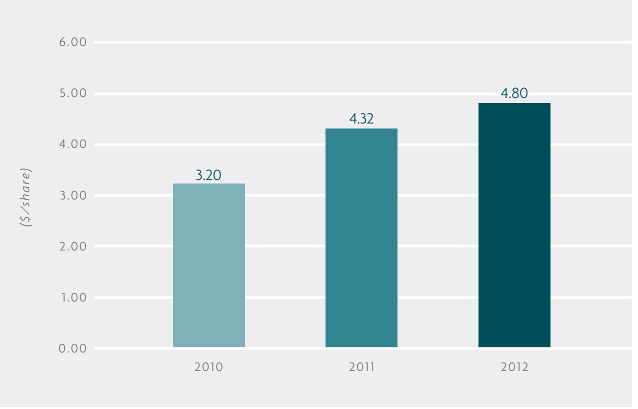
- Upstream operating cash flow of $3,169 million, an improvement of $288 million, due to higher crude oil and NGLs volumes, partially offset by lower realized crude oil and natural gas prices and lower natural gas volumes; and
- Operating cash flow of $1,267 million from our Refining and Marketing segment increasing $286 million on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

Cash Flow

Cash flow of $3,643 million, increasing $367 million or 11 percent, primarily due to higher operating cash flow, partially offset by:

- An increase in current income tax, excluding tax on divestitures, of $168 million mainly due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and improved operating cash flow from our Canadian operations; and
- An increase in our general and administrative expenses due to higher staffing and office support costs in-line with our growth.

CASH FLOW PER SHARE – DILUTED



Operating Earnings

Operating earnings of $866 million, decreasing $373 million or 30 percent primarily due to the following non-cash items:

- Goodwill impairment of $393 million in our Conventional segment at Suffield, resulting primarily from declining future cash flows due to lower natural gas and crude oil prices and increased operating costs. We have also had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the goodwill which arose in 2002, exceeded its fair value;
- Increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates; and
- Increased exploration expense.

Higher cash flow partially offset the decreases in operating earnings as discussed above.

Net Earnings

Net earnings of $993 million, decreasing $485 million or 33 percent, as decreases in operating earnings discussed above, decreases in unrealized risk management gains, after tax and a gain on divestiture in 2011 were partially offset by higher unrealized foreign exchange gains.

Capital Investment

Capital investment of $3,368 million, increasing $645 million or 24 percent primarily due to expansion of our Oil Sands operations and the development of tight oil opportunities in our Conventional segment, partially offset by reduced capital spending in Refining and Marketing with the completion of the CORE project in 2011.

OPERATING RESULTS

CRUDE OIL PRODUCTION VOLUMES

(barrels per day)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Oil Sands					
Foster Creek	**57,833**	**5%**	54,868	7%	51,147
Christina Lake	**31,903**	**173%**	11,665	48%	7,898
Pelican Lake	**22,552**	**10%**	20,424	-11%	22,966
Conventional					
Heavy Oil	**16,015**	**2%**	15,657	-6%	16,659
Light & Medium Oil	**36,071**	**18%**	30,524	4%	29,346
NGLs [1]	**1,029**	**-7%**	1,101	-6%	1,171
	165,403	**23%**	134,239	4%	129,187

(1) NGLs include condensate volumes.

In 2012, our crude oil and NGLs production increased 23 percent due to the start-up of Christina Lake phases C and D in the third quarters of 2011 and 2012 respectively, improved well performance and plant optimization at Foster Creek and rising production at Pelican Lake from our infill drilling and polymer flood program. Our successful drilling program in Alberta and drilling, completions and facilities work in Saskatchewan, also contributed to higher production.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Conventional	**561**	**-9%**	619	-11%	694
Oil Sands	**33**	**-11%**	37	-14%	43
	594	**-9%**	656	-11%	737

In 2012, our natural gas production declined nine percent. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years. Declines were also a result of the divestiture of our Boyer property in early 2012, partially offset by the absence of weather related production issues that were encountered in 2011. Excluding the impact of the first quarter divestiture, our natural gas production would have decreased six percent.

OPERATING NETBACKS

	2012		2011		2010	
	Crude Oil & NGLs *($/bbl)*	**Natural Gas *($/Mcf)***	Crude Oil & NGLs *($/bbl)*	Natural Gas *($/Mcf)*	Crude Oil & NGLs *($/bbl)*	Natural Gas *($/Mcf)*
Price [1]	**65.79**	**2.42**	72.84	3.65	62.96	4.09
Royalties	**6.29**	**0.03**	9.84	0.06	9.33	0.07
Transportation and Blending [1]	**2.65**	**0.10**	2.76	0.15	1.88	0.17
Operating Expenses	**13.90**	**1.10**	13.47	1.10	11.74	0.95
Production and Mineral Taxes	**0.56**	**0.01**	0.56	0.04	0.62	0.02
Netback Excluding Realized Risk Management	**42.39**	**1.18**	46.21	2.30	39.39	2.88
Realized Risk Management Gains (Losses)	**1.39**	**1.14**	(2.79)	0.87	(0.36)	1.07
Netback Including Realized Risk Management	**43.78**	**2.32**	43.42	3.17	39.03	3.95

(1) Heavy crude oil is mixed with purchased condensate. The crude oil and NGLs price and transportation and blending costs exclude the impact of condensate purchases of $26.72 per barrel (2011 – $24.91 per barrel; 2010 – $20.36 per barrel).

In 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $3.82 per barrel from 2011. Sales prices were lower in 2012, consistent with lower benchmark prices and decreased sales prices for Christina Lake due to the Christina Dilbit Blend ("CDB") differential to Western Canadian Select ("WCS"). In addition, higher operating costs as a result of workover activities, workforce and repairs and maintenance costs also decreased our average netback. This decrease was offset by a reduction in royalties primarily due to increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.12 per Mcf in 2012 predominantly as a result of lower sales prices as compared to 2011.

REFINING [1]

	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Crude Oil Runs *(Mbbls/d)*	**412**	**3%**	401	4%	386
Refined Product *(Mbbls/d)*	**433**	**3%**	419	3%	405
Crude Utilization *(percent)*	**91**	**2%**	89	3%	86

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

Crude oil runs and refined product improved three percent as a result of a full year of operations after completion of the CORE project at the Wood River Refinery. Improvements were partially offset by longer than expected planned turnarounds at both refineries in the fourth quarter of 2012.

Further information on the changes in our production volumes and items included in our operating netbacks can be found in the Reportable Segments section of this MD&A. Further information on our risk management strategy can be found in the Risk Management section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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 selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

SELECTED BENCHMARK PRICES AND EXCHANGE RATES [1]

	Q4 2012	2012	2011	2010
Crude Oil Prices *(US$/bbl)*				
Brent Futures				
Average	**110.13**	**111.68**	110.91	80.34
End of period	**111.11**	**111.11**	107.38	94.75
WTI				
Average	**88.23**	**94.15**	95.11	79.61
End of period	**91.82**	**91.82**	98.83	91.38
Average Differential Brent-WTI	**21.90**	**17.53**	15.80	0.73
WCS				
Average	**70.12**	**73.12**	77.96	65.38
End of period	**59.16**	**59.16**	84.37	72.87
Average Differential WTI-WCS	**18.11**	**21.03**	17.15	14.23
Condensate (C5 @ Edmonton) Average	**98.14**	**100.88**	105.34	81.91
Average Differential WTI-Condensate Premium	**(9.91)**	**(6.73)**	(10.23)	(2.30)
Refining Margin 3-2-1 Average Crack Spreads [2] *(US$/bbl)*				
Chicago	**28.18**	**27.76**	24.55	9.33
Midwest Combined ("Group 3")	**28.49**	**28.56**	25.26	9.48
Natural Gas Average Prices				
AECO *($/GJ)*	**2.90**	**2.28**	3.48	3.91
NYMEX *(US$/MMBtu)*	**3.40**	**2.79**	4.04	4.39
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.31**	**0.38**	0.31	0.40
U.S./Canadian Dollar Exchange Rate				
Average	**1.009**	**1.001**	1.012	0.971

(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Operating Netbacks table in the Operating Results section of this MD&A.

(2) The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and a last in, first out accounting basis ("LIFO").

Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and is also a better indicator than WTI of changes in inland refined product prices, which are tied to global markets. In 2012, the average price of Brent crude oil was roughly the same as in 2011, averaging near US$112 per barrel, as the effects of weak demand growth, was offset by supply outages caused by operational and geopolitical problems. Demand weakness was the result of weak European and North American economies, as governments addressed fiscal imbalances and slowing Chinese growth, as authorities tried to reduce the inflated value of products within the Chinese economy.

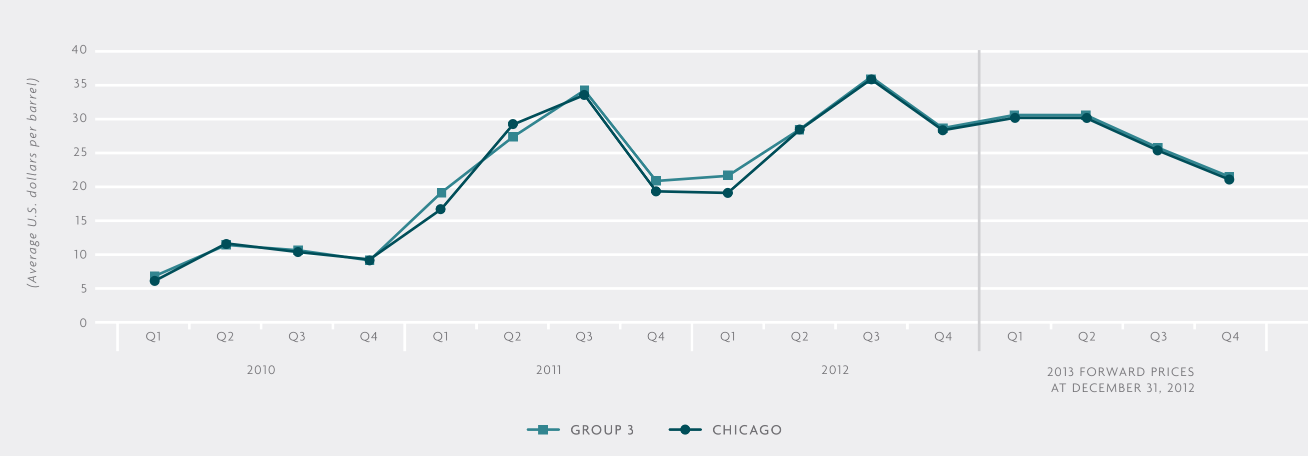
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI has been trading at a significant discount to Brent prices for the past two years as inland supply growth has strained the capacity of takeaway transportation from inland markets. These discounts widened somewhat in 2012 as additional transportation capacity provided by reversing the Seaway pipeline to flow out of the U.S. Midwest, was more than offset by growth in inland supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential widened in 2012, primarily due to greater transportation congestion out of the Western Canadian Sedimentary Basin ("WCSB"), despite increased supply outages and availability of rail capacity.

Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The WTI-Condensate differential is the Edmonton benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. Condensate differentials at Edmonton weakened in 2012 by US$3.50 per barrel due largely to the continued strong growth in North American condensate supply, mostly from the Eagleford basin in Texas, offset partially by increased costs of transport to the Edmonton market.

Refining 3-2-1 Crack Spread Benchmarks

Average 2012 crack spreads in the U.S. inland Chicago and Group 3 markets increased from strong 2011 levels due to increased North American crude oil discounts and global refinery closures.



Benchmark crack spreads are a simplified view of the market based on LIFO and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and feedstock costs based on first in, first out accounting basis.

Other Benchmarks

Average natural gas prices in 2012 fell sharply from 2011 levels due to one of the warmest winters on record coupled with continued strong growth in North American supply despite a falling rig count. In order to create sufficient demand to offset these imbalances, gas prices fell sufficiently to induce fuel switching away from coal-fired power generation to gas-fired power generation.

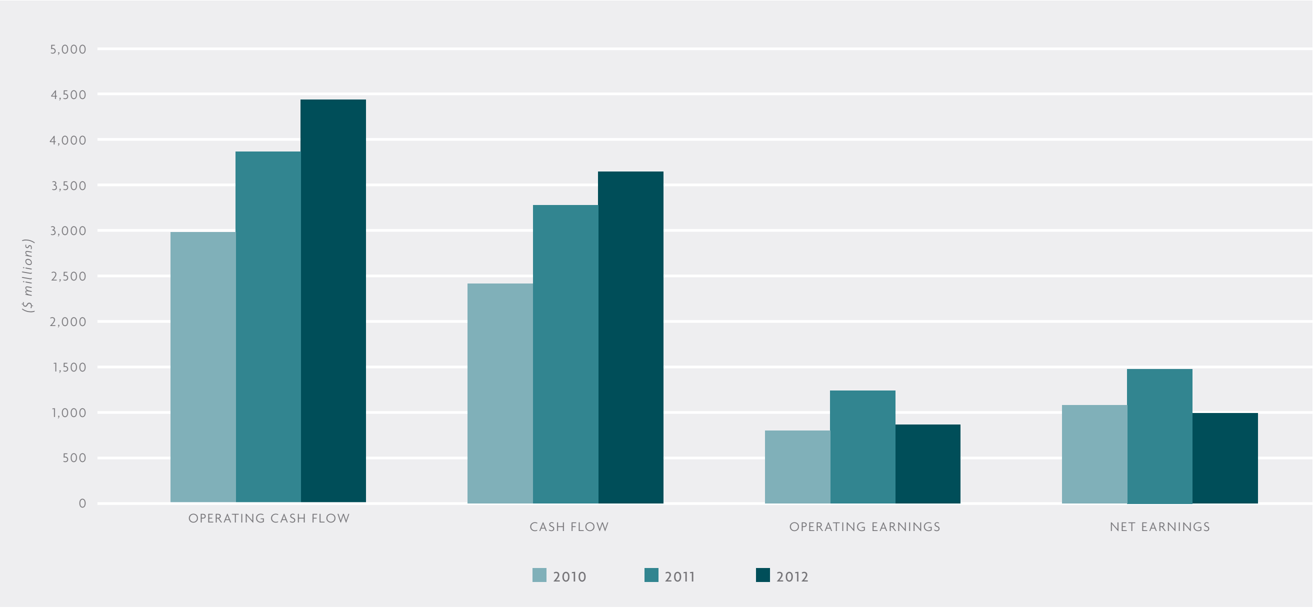
A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar increases our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. During 2012, the Canadian dollar weakened slightly relative to the U.S. dollar, but remained close to parity.

FINANCIAL RESULTS

SELECTED CONSOLIDATED FINANCIAL RESULTS

The following key performance indicators are discussed in more detail within this section:

OPERATING CASH FLOW, CASH FLOW, OPERATING EARNINGS AND NET EARNINGS



($ millions, except per share amounts)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Revenues	**16,842**	**7%**	15,696	24%	12,641
Operating Cash Flow [1]	**4,436**	**15%**	3,862	30%	2,981
Cash Flow [1]	**3,643**	**11%**	3,276	36%	2,412
per Share – Diluted	**4.80**	**11%**	4.32	35%	3.20
Operating Earnings [1]	**866**	**-30%**	1,239	55%	799
per Share – Diluted	**1.14**	**-30%**	1.64	55%	1.06
Net Earnings	**993**	**-33%**	1,478	37%	1,081
per Share – Basic	**1.31**	**-33%**	1.96	36%	1.44
per Share – Diluted	**1.31**	**-33%**	1.95	36%	1.43
Total Assets	**24,216**	**9%**	22,194	12%	19,840
Total Long-Term Financial Liabilities	**6,128**	**13%**	5,411	-4%	5,618
Capital Investment [2]	**3,368**	**24%**	2,723	29%	2,115
Cash Dividends	**665**	**10%**	603	0%	601
per Share	**0.88**	**10%**	0.80	0%	0.80

(1) Non-GAAP Measure and defined in this MD&A.

(2) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

REVENUE VARIANCE

($ millions)	2012 vs. 2011	2011 vs. 2010
Revenues, Comparative Year	**15,696**	12,641
Increase (Decrease) due to:		
Oil Sands	**866**	584
Conventional	**(227)**	9
Refining and Marketing	**731**	2,397
Corporate and Eliminations	**(224)**	65
Revenues, End of Year	**16,842**	15,696

Oil Sands revenues increased 29 percent primarily due to increased crude oil and condensate volumes, partially offset by decreased average crude oil prices. Conventional revenues decreased by 11 percent as crude oil and NGLs production increases were offset by lower crude oil prices and lower natural gas production and prices. Revenues generated by the Refining and Marketing segment rose by seven percent as a result of increased refined product output and higher refined product prices, despite reduced output levels during planned turnarounds. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility also increased revenues. Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

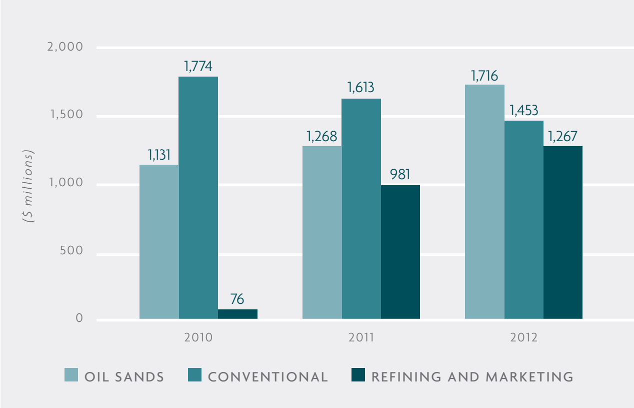
OPERATING CASH FLOW

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

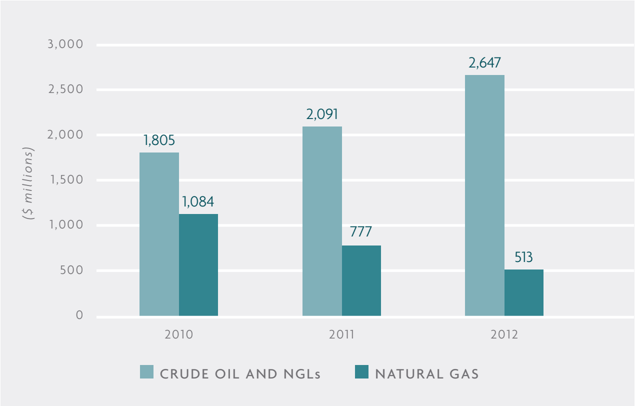
($ millions)	2012	2011	2010
Revenues (1)	**17,125**	15,755	12,765
(Add Back) Deduct:			
Purchased Product (1)	**9,506**	9,149	7,674
Transportation and Blending	**1,798**	1,369	1,065
Operating Expenses (1)	**1,684**	1,407	1,289
Production and Mineral Taxes	**37**	36	34
Realized Gain on Risk Management Activities (1)	**(336)**	(68)	(278)
Operating Cash Flow	**4,436**	3,862	2,981

(1) Excludes any revenues, purchased product and operating expenses included in the Corporate and Eliminations segment. See the notes to the Consolidated Financial Statements for details.

OPERATING CASH FLOW BY SEGMENT



OPERATING CASH FLOW BY UPSTREAM PRODUCT

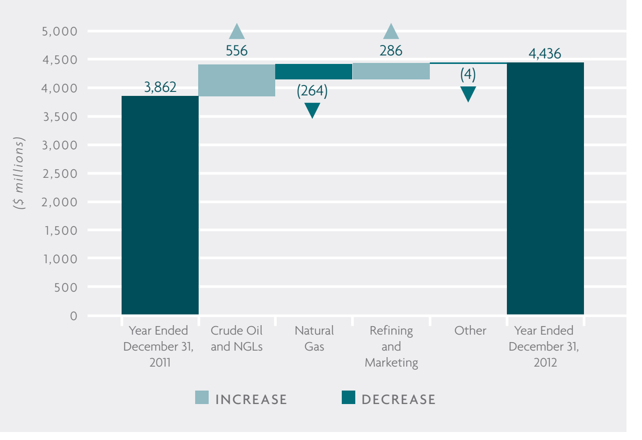


Operating Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011

Overall, operating cash flow increased $574 million or 15 percent as operating cash flow from crude oil and NGLs and Refining and Marketing increased 27 percent and 29 percent, respectively.

The increase in operating cash flow from crude oil and NGLs was driven by increased production volumes, partially offset by lower average crude oil sales prices and higher operating costs. Operating cash flow from natural gas declined $264 million (34 percent), as a result of lower average sales prices combined with reduced production volumes from expected natural declines and the divestiture of a non-core natural gas property in the first quarter of 2012. Refining and Marketing operating cash flow rose on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.



CASH FLOW

Cash flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

($ millions)	**2012**	2011	2010
Cash From Operating Activities	**3,420**	3,273	2,591
(Add Back) Deduct:			
Net Change in Other Assets and Liabilities	**(113)**	(82)	(55)
Net Change in Non-Cash Working Capital	**(110)**	79	234
Cash Flow	**3,643**	3,276	2,412

Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011

In 2012, our cash flow increased $367 million or 11 percent primarily due to:

- A 25 percent increase in our crude oil and NGLs sales volumes;
- An increase in operating cash flow from Refining and Marketing of $286 million due to improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds;
- Realized risk management gains before tax, excluding Refining and Marketing, of $332 million compared to gains of $82 million in 2011; and
- A decrease in royalties of $102 million primarily as a result of increased capital investment at Foster Creek and Pelican Lake. In 2011, inclusion of the Foster Creek expansion phases F, G and H capital investment was approved as part of the Foster Creek royalty calculation, resulting in a $65 million reduction in royalties in 2011.

The increases in our cash flow for 2012 were partially offset by:

- A 10 percent decrease in the average realized sales price of crude oil and NGLs to $65.79 per barrel;
- A 34 percent decrease in the average natural gas sales price to $2.42 per Mcf;
- An increase in operating expenses of $171 million, primarily from increased crude oil production at all of our upstream properties with crude oil per barrel operating costs increasing three percent to $13.99 per barrel;
- Increase in other expenditures of $219 million, primarily related to a $168 million increase in current income tax due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and higher Canadian tax due to improved operating cash flow from our Canadian operations; and
- A nine percent decline in natural gas production, primarily as a result of expected natural declines and the divestiture of a non-core property early in the first quarter of 2012.

OPERATING EARNINGS

Operating earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating earnings is defined as net earnings excluding the after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax gains (losses) on non-operating foreign exchange, after-tax effect of gains (losses) on divestiture of assets and the effect of changes in statutory income tax rates.

($ millions)	**2012**	2011	2010
Net Earnings	**993**	1,478	1,081
(Add Back) Deduct:			
Unrealized Risk Management Gains (Losses), after-tax [1]	**43**	134	34
Non-Operating Unrealized Foreign Exchange Gains (Losses), after-tax [2]	**84**	14	153
Gain (Loss) on Divestiture of Assets, after-tax	**–**	91	83
Gain (Loss) on Bargain Purchase, after-tax	**–**	–	12
Operating Earnings	**866**	1,239	799

(1) The unrealized risk management gains (losses), after-tax include 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 deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings of $866 million, decreased $373 million or 30 percent primarily due to a goodwill impairment, increased DD&A and exploration expense, partially offset by higher cash flow as discussed above.

NET EARNINGS VARIANCE

($ millions)	**2012 vs. 2011**	2011 vs. 2010
Net Earnings, Comparative Year	**1,478**	1,081
Increase (Decrease) due to:		
Operating Cash Flow	**574**	881
Corporate and Eliminations:		
Unrealized Risk Management Gains (Losses), after-tax	**(91)**	100
Unrealized Foreign Exchange Gains (Losses)	**28**	(27)
Gain (Loss) on Divestiture of Assets	**(107)**	(9)
Expenses (1)	**(52)**	(86)
Depreciation, Depletion and Amortization	**(290)**	7
Goodwill Impairment	**(393)**	–
Exploration Expense	**(68)**	3
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gains (Losses)	**(86)**	(472)
Net Earnings, End of Year	**993**	1,478

(1) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net and Corporate and Eliminations operating expenses.

Year over year, our net earnings decreased $485 million or 33 percent, primarily as a result of a goodwill impairment and the absence of gains recorded on divestitures of assets in 2012. Significant factors that impacted our net earnings for the year include:

- Goodwill impairment of $393 million on the carrying amount of the Suffield cash generating unit ("CGU") within our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area;
- An increase of $290 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs associated with total proved reserves and increased depreciable costs in Refining and Marketing, partially offset by decreased natural gas production;
- No gains recorded on divestitures of assets during 2012 as compared to a gain of $107 million in 2011;
- Unrealized risk management gains, after-tax, of $43 million, compared to gains of $134 million in 2011;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $769 million, compared to $683 million in 2011;
- An increase in exploration expense of $68 million; and
- An increase of $57 million for general and administrative expenses primarily due to higher staffing and office support costs.

Partially offset by:

- Increased operating cash flow as discussed previously; and
- Unrealized foreign exchange gains of $70 million compared to a gain of $42 million in 2011, consistent with the strengthening of the Canadian dollar exchange rate at December 31, 2012 resulting from the translation of our U.S. dollar long-term debt and Partnership Contribution Receivable.

NET CAPITAL INVESTMENT

($ millions)	**2012**	2011	2010
Oil Sands	**2,211**	1,415	857
Conventional	**848**	788	526
Refining and Marketing	**118**	393	656
Corporate and Eliminations	**191**	127	76
Capital Investment	**3,368**	2,723	2,115
Acquisitions (2)	**114**	71	86
Divestitures	**(76)**	(173)	(307)
Net Capital Investment (1)	**3,406**	2,621	1,894

(1) Includes expenditures on PP&E and E&E.

(2) Asset acquisition included the assumption of a decommissioning liability of $33 million.

Oil Sands capital investment increased primarily due to higher spending at Foster Creek on module assembly and facility construction for phase F, piling work, steel fabrication, module assembly and major equipment procurement for phase G and design engineering for phase H. In addition, Foster Creek also incurred main facility and infrastructure spending. At Christina Lake, the increase in capital investment included drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, as well as phase F site preparation, engineering and major equipment fabrication. Pelican Lake capital investment included infill drilling for expansion of the polymer flood, facility expansion, pipeline construction and maintenance capital. Capital investment in 2012 included the drilling of 473 gross stratigraphic test wells, down from the

480 gross wells drilled during 2011. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.

Conventional capital investment in 2012 was centered on the development of our crude oil properties including drilling, completion and major facilities work in Saskatchewan as well as drilling completion and tie-in in Alberta focused on tight oil opportunities.

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

Included in our capital investment is spending on technology development. Our teams look for ways to either improve existing technology or pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas. One of our ongoing objectives is to advance technologies that increase production while minimizing the use of water, natural gas, electricity and land. This philosophy is evidenced through the use of our Wedge Well™ technology at Foster Creek and Christina Lake, the use of enhanced start-up techniques at Christina Lake phase C and the development of our SkyStrat™ drilling rig used for the drilling of stratigraphic wells in remote areas.

Capital investment in our Corporate and Eliminations segment was for information technology and tenant improvements to new office space.

Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Acquisitions and Divestitures

The acquisitions were primarily for oil sands properties adjacent to our Telephone Lake and Narrows Lake properties as well as producing conventional crude oil properties in Alberta and Saskatchewan located adjacent to existing production. Divestitures in 2012 were mainly related to the sale of our Boyer natural gas property, located in northern Alberta, in the first quarter.

CAPITAL INVESTMENT DECISIONS

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow.

($ millions)	**2012**	2011	2010
Cash Flow	**3,643**	3,276	2,412
Capital Investment (Committed and Growth)	**3,368**	2,723	2,115
Free Cash Flow (1)	**275**	553	297
Dividends Paid	**665**	603	601
	(390)	(50)	(304)

(1) Free Cash Flow is a non-GAAP measure defined as cash flow less capital investment.

Over the next decade, we expect to increase our net crude oil production to approximately 500,000 barrels per day. In order to meet these project targets, we anticipate capital expenditures to average between $3.0 and $3.5 billion a year. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. In August 2012, we completed a public debt offering for the principal amount of US$1.25 billion. As at December 31, 2012, we have cash and cash equivalents of approximately $1.2 billion to fund future capital investment. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of our financial metrics.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

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 Phillips 66. 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 and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, 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.

REVENUE BY REPORTABLE SEGMENT

($ millions)	**2012**	2011	2010
Oil Sands	**3,873**	3,007	2,423
Conventional	**1,896**	2,123	2,114
Refining and Marketing	**11,356**	10,625	8,228
Corporate and Eliminations	**(283)**	(59)	(124)
	16,842	15,696	12,641

OIL SANDS

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

Significant factors that impacted our Oil Sands segment in 2012 include:

- Early completion of phase D at Christina Lake with production starting up in the third quarter of 2012;
- Foster Creek demonstrating excellent operating performance in 2012, exceeding nameplate capacity of 120,000 gross barrels per day for six months of the year;
- Expansion work at phases F, G and H at Foster Creek is progressing with added production capacity from phase F expected in the third quarter of 2014; and
- Receiving regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A.

OIL SANDS – CRUDE OIL

Financial Results

($ millions)	**2012**	2011	2010
Gross Sales	**4,037**	3,217	2,610
Less: Royalties	**215**	282	276
Revenues	**3,822**	2,935	2,334
Expenses			
Transportation and Blending	**1,651**	1,229	934
Operating	**548**	409	339
(Gains) Losses on Risk Management	**(62)**	87	14
Operating Cash Flow	**1,685**	1,210	1,047
Capital Investment	**2,203**	1,401	850
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**(518)**	(191)	197

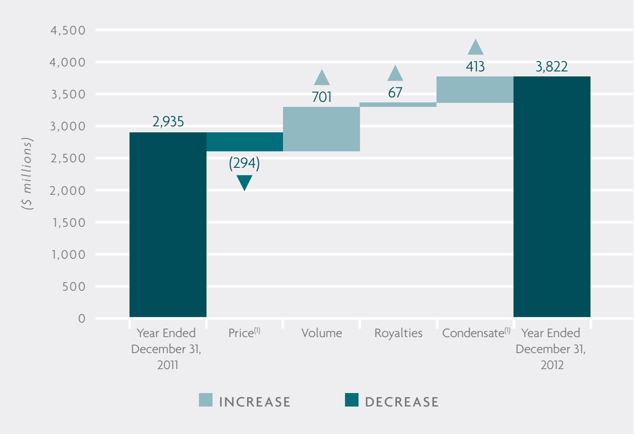
Capital expenditures in excess of operating cash flow for the Oil Sands segment are funded through operating cash flow generated by our conventional and refining operations.

Revenues

PRICING

In 2012, our average crude oil sales price was $60.84 per barrel, an 11 percent decrease from 2011, generally consistent with the decrease in the WCS benchmark price.

In 2012, with the introduction of a new crude stream to the market, CDB, approximately 74 percent (2011 – 12 percent) of our Christina Lake production was sold as CDB which sells at a discount to WCS. As the year progressed, the discount from WCS decreased as CDB became more widely accepted as a crude stream. The remaining Christina Lake production is being sold as part of the WCS stream and is subject to a quality equalization charge.



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

PRODUCTION

In 2012, the substantial increase in production at Christina Lake resulted from the start-up of phase C in the third quarter of 2011 and phase D coming on production in late July 2012, three months ahead of schedule. Foster Creek production increased due to improved well performance and plant optimization. In 2012, both Christina Lake and Foster Creek achieved new single day production highs of 93,936 and 130,580 gross barrels per day, respectively. Pelican Lake production rose steadily with production averaging 10 percent higher than 2011. The increases at Pelican Lake resulted from infill wells being brought on production in 2012. In addition, 2011 production was curtailed due to a scheduled plant turnaround and wild fires.

Crude Oil (barrels per day)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Foster Creek	**57,833**	**5%**	54,868	7%	51,147
Christina Lake	**31,903**	**173%**	11,665	48%	7,898
	89,736	**35%**	66,533	13%	59,045
Pelican Lake	**22,552**	**10%**	20,424	-11%	22,966
	112,288	**29%**	86,957	6%	82,011

ROYALTIES

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined by the Canadian dollar equivalent WTI benchmark price. Royalties at Christina Lake are based on a pre-payout, monthly calculation using the pre-payout royalty rate applied to the net revenue from the project, which is impacted by volumes and realized prices. Foster Creek and Pelican Lake royalties are based on a post-payout, annualized calculation using the post-payout royalty rate applied to a net profit from the project which is impacted by volumes, realized prices as well as allowed operating and capital costs.

Royalties decreased $67 million during 2012, primarily due to increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets and a $65 million decrease in 2011 royalties upon receiving approval for the inclusion of Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for 2012 were 11.8 percent at Foster Creek (2011 – 16.8 percent), 6.2 percent at Christina Lake (2011 – 5.2 percent) and 5.0 percent at Pelican Lake (2011 – 11.5 percent).

Expenses

TRANSPORTATION AND BLENDING

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce its viscosity in order to transport the product to market. Transportation and blending costs rose $422 million or 34 percent in 2012. The majority of the cost increase, $413 million, stems from additional condensate volumes required to blend as a result of higher production at Christina Lake and Foster Creek. This was partially offset by lower transportation charges on the Trans Mountain pipeline system under our long-term commitment for firm service, which commenced in February 2012.

OPERATING

Our operating costs for 2012 were primarily for workforce, workover activities, repairs and maintenance, chemical usage and fuel costs at Foster Creek and Christina Lake. In total, operating costs increased $139 million in 2012 mainly due to higher staffing levels, fuel consumption, chemicals and fluid and waste handling and trucking costs associated with the start-up of Christina Lake phases C and D which increased gross production capacity by 80,000 barrels per day. Overall, on a per barrel basis, operating costs were $13.33 (2011 – $13.27). On a per barrel basis, Christina Lake operating costs decreased 36 percent to $12.95 per barrel due to the increase in production. Foster Creek operating costs increased $0.65 per barrel to $11.99 per barrel due to increased workforce costs, higher waste handling, trucking and workover activity. Operating costs increased $2.22 per barrel at Pelican Lake primarily as the result of additional workover activities, workforce and increased polymer consumption as a result of the expansion of the polymer flood.

RISK MANAGEMENT

Risk management activities resulted in realized gains of $62 million (2011 – losses of $87 million), consistent with our 2012 contract prices exceeding average benchmark prices in 2012.

OIL SANDS – NATURAL GAS

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production decreased to 33 MMcf per day in 2012 (2011 – 37 MMcf per day) as the result of anticipated natural declines, partially offset by a reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues in the first quarter of 2012 and reduced volumes in the fourth quarter as a result of lower natural gas prices.

Reduced natural gas production in combination with lower prices resulted in operating cash flow declining to $31 million for 2012 (2011 – $52 million).

OIL SANDS – CAPITAL INVESTMENT

($ millions)	**2012**	2011	2010
Foster Creek	**735**	429	277
Christina Lake	**579**	472	346
	1,314	901	623
Pelican Lake	**518**	317	104
Narrows Lake	**44**	19	10
Telephone Lake	**138**	61	27
Grand Rapids	**65**	31	59
Other (1)	**132**	86	34
Capital Investment (2)	**2,211**	1,415	857

(1) Includes new resource plays and Athabasca natural gas.

(2) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2012 has been primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, facility expansion and infill drilling activities related to our Pelican Lake polymer flood, drilling of stratigraphic test wells to support the development of our Oil Sands projects and commencing operation of our dewatering pilot at Telephone Lake in the fourth quarter. In addition, capital investment increased at Narrows Lake as site preparation commenced for phase A. Construction of the phase A plant is scheduled to start in the third quarter of 2013.

Foster Creek

Foster Creek capital investment increased in 2012 compared to 2011 primarily as a result of higher phase F spending on module assembly and facility construction, phase G spending on piling work, steel fabrication, module assembly and major equipment procurement and phase H design engineering. Capital includes the drilling of 141 gross stratigraphic test wells in 2012 (2011 – 118 wells) and higher spending on the main facility and infrastructure. First production at phase F is expected in the third quarter of 2014 increasing production capacity by 45,000 gross barrels per day.

Christina Lake

Christina Lake capital investment increased in 2012 compared to 2011 primarily due to drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, phase F site preparation, engineering and major equipment fabrication and phase G design engineering, in addition to maintenance capital. Capital investment also included the drilling of stratigraphic test wells (2012 – 29 gross wells; 2011 – 63 gross wells). The increases in capital investment were partially offset by the completion of phases C and D construction in the second quarters of 2011 and 2012, respectively.

Pelican Lake

Pelican Lake capital investment in 2012 was primarily related to infill drilling to progress the polymer flood, facilities expansions, pipeline construction and maintenance capital. Facilities spending focused on expanding fluid handling capacity at Pelican Lake through additions and upgrades to our crude oil treating units and emulsion pipelines.

Telephone Lake

At Telephone Lake capital investment was primarily related to drilling, infrastructure, fuel storage and facility construction related to the dewatering pilot which started up in the fourth quarter of 2012.

Gross Production Wells Drilled [1]

	2012	2011	2010
Foster Creek	**28**	21	37
Christina Lake	**32**	19	32
	60	40	69
Pelican Lake	**76**	31	12
Grand Rapids	**1**	–	1
Other	**–**	3	–
	137	74	82

(1) Includes wells drilled using our Wedge Well™ technology.

FUTURE CAPITAL INVESTMENT

Expansion work at phases F, G and H at Foster Creek is proceeding as planned with additional production capacity from phase F expected in the third quarter of 2014. Progress is also being made for phase G on module assembly and facility construction and on phase H engineering and procurement is continuing with piling work and module assembly, scheduled to start in 2013. We anticipate submitting an application to regulators in 2013 for an additional expansion, phase J.

Production from phase E at Christina Lake is anticipated in the third quarter of 2013, a few months earlier than originally planned. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G. Expansion work on these phases is continuing in 2013 with module assembly, facility construction and procurement for phase F and detailed engineering for phase G.

In 2012, Narrows Lake received regulatory approval for phases A, B and C, and partner approval for phase A. Site preparation is underway, with construction of the phase A plant scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $140 million and $160 million in 2013.

Additional capital of approximately $270 to $300 million is expected to be invested in the emerging SAGD projects including Grand Rapids and Telephone Lake in 2013. We anticipate regulatory approval for Grand Rapids by the end of 2013. Steam injection started on the second pilot well pair during the third quarter of 2012, with first production expected early in 2013. At Telephone Lake, we are advancing the regulatory application for the project and continuing with operation of the dewatering pilot. We anticipate receiving regulatory approval in 2014.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed another large stratigraphic test well program in the first quarter of 2012. The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake are to support the expansion phases, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs between the end of the fourth quarter and the end of the first quarter. In 2012 we developed the SkyStrat™ drilling rig, which uses a helicopter and an experimental lightweight drilling rig to allow stratigraphic well drilling to be completed in remote exploratory drilling locations year-round.

Our 2012 stratigraphic test well program provided the primary basis for the 1.4 billion barrel increase to our economic bitumen best estimate contingent resources as results from the program caused prospective resources to be reclassified as contingent resources. Additional information about our resources, including definitions and year end results, is included in the Oil and Gas Reserves and Resources section of this MD&A.

GROSS STRATIGRAPHIC TEST WELLS DRILLED

	2012	2011	2010
Foster Creek	**141**	118	82
Christina Lake	**29**	63	24
	170	181	106
Pelican Lake	**5**	57	–
Narrows Lake	**42**	47	39
Grand Rapids	**62**	59	71
Telephone Lake	**29**	40	26
Borealis	**59**	44	–
Other	**106**	52	17
	473	480	259

CONVENTIONAL

Our Conventional operations include the development and production of crude oil and NGLs and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In Saskatchewan, our Conventional properties are predominantly crude oil producing properties, most notably the carbon dioxide enhanced oil recovery project in Weyburn. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to continue to assess the potential of new crude oil projects within our existing properties, as well as new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2012 include:

- Alberta crude oil and NGLs production averaging 30,357 barrels per day, increasing 10 percent primarily due to successful tight oil drilling programs and fewer weather and access issues than in 2011;
- Completing the construction and commissioning of batteries in both the Bakken and Lower Shaunavon areas, including all supporting infrastructure, to support production in the respective areas;
- Bakken and Lower Shaunavon crude oil and NGLs production averaging 6,480 barrels per day, a 79 percent increase due to ongoing drilling; and
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $439 million, a decrease of 30 percent from 2011. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years.

CONVENTIONAL – CRUDE OIL AND NGLS

Financial Results

($ millions)	**2012**	2011	2010
Gross Sales	**1,559**	1,492	1,229
Less: Royalties	**166**	193	153
Revenues	**1,393**	1,299	1,076
Expenses			
Transportation and Blending	**126**	104	86
Operating	**294**	244	199
Production and Mineral Taxes	**34**	27	28
(Gains) Losses on Risk Management	**(23)**	43	5
Operating Cash Flow	**962**	881	758
Capital Investment	**805**	686	363
Operating Cash Flow in Excess of Related Capital Investment	**157**	195	395

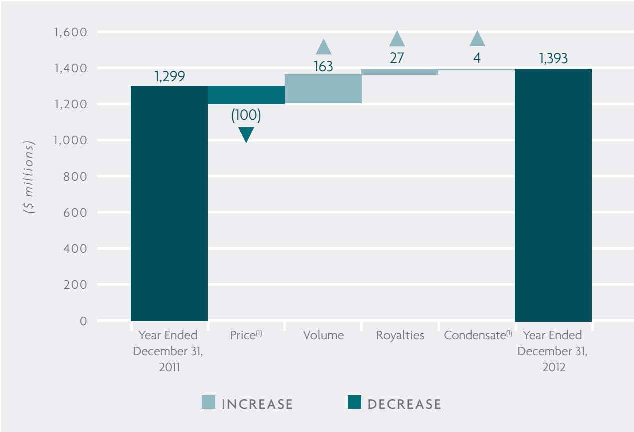
Revenues

PRICING

Our average crude oil and NGLs sales price in 2012 decreased six percent to $76.25 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

PRODUCTION

Our crude oil and NGLs production increased 12 percent in 2012 as a result of successful drilling completion and tie-in programs. Production in Alberta increased 10 percent to an average of 30,357 barrels per day and production in Saskatchewan increased 15 percent to an average of 22,758 barrels per day.



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil and NGLs price excludes the impact of condensate purchases.

PRODUCTION (CONTINUED)

(barrels per day)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Heavy Oil					
Alberta	**16,015**	**2%**	15,657	-6%	16,659
Light and Medium Oil					
Alberta	**13,378**	**24%**	10,763	-1%	10,854
Saskatchewan	**22,693**	**15%**	19,761	7%	18,492
NGLs	**1,029**	**-7%**	1,101	-6%	1,171
	53,115	**12%**	47,282	0%	47,176

ROYALTIES

Royalties decreased $27 million largely due to lower royalties in Weyburn primarily as a result of lower realized crude oil prices. The effective crude oil royalty rate in 2012 for the Conventional segment was 11.8 percent (2011 – 14.2 percent). Most of our crude oil and NGLs production in the Conventional segment is located on fee land which results in mineral tax recorded within production and mineral taxes.

Expenses

TRANSPORTATION AND BLENDING

Transportation and blending costs increased $22 million in 2012. The overall cost of condensate used in blending increased $4 million as slightly lower prices only partially offset increased usage in our heavy oil operations. Transportation costs increased $18 million due to higher produced volumes, an increase of trucking expenses attributable to the clean oil sold out of Shaunavon prior to the construction of the pipeline connected battery, a higher proportion of our volumes being subject to spot pipeline tolls and increased costs associated with accessing new markets, such as transporting our growing light and medium crude oil production by rail.

OPERATING

Operating costs are predominantly comprised of workover activities, electricity, repairs and maintenance and workforce. Operating costs increased $50 million in 2012 primarily due to a combination of fluid waste handling and trucking costs, additional workover activities, repairs and maintenance in connection with single well batteries and higher workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil which has resulted in higher crude oil production.

RISK MANAGEMENT

Risk management activities in 2012 resulted in realized gains of $23 million (2011 – loss of $43 million), consistent with our contract prices exceeding the average benchmark prices.

OPERATING CASH FLOW IN EXCESS OF CAPITAL INVESTMENT

Operating cash flow from crude oil and NGLs in excess of capital investment decreased by $38 million in 2012 as the $81 million increase in operating cash flow was more than offset by the $119 million increase in capital investment which was focused on drilling, completions and facilities work in Alberta and Saskatchewan.

CONVENTIONAL – NATURAL GAS

Financial Results

($ millions)	**2012**	2011	2010
Gross Sales	**496**	825	1,042
Less: Royalties	**6**	12	17
Revenues	**490**	813	1,025
Expenses			
Transportation and Blending	**19**	34	44
Operating	**215**	240	231
Production and Mineral Taxes	**3**	9	6
Gains on Risk Management	**(229)**	(195)	(263)
Operating Cash Flow	**482**	725	1,007
Capital Investment	**43**	102	163
Operating Cash Flow in Excess of Related Capital Investment	**439**	623	844

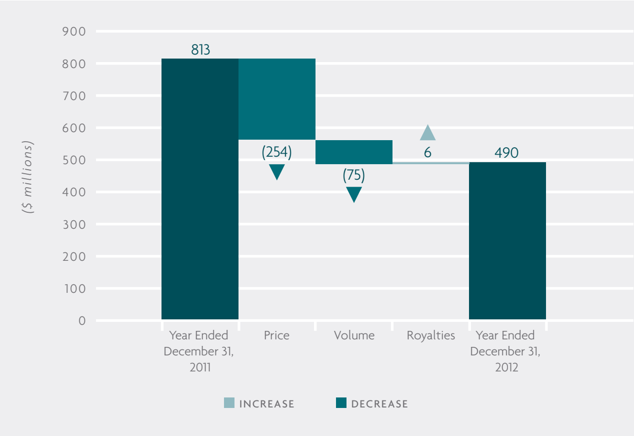
Revenues

PRICING

Our average natural gas sales price in 2012 decreased to $2.42 per Mcf compared to $3.65 per Mcf in 2011, consistent with the decline in the benchmark AECO price.

PRODUCTION

Our Conventional natural gas production decreased nine percent to 561 MMcf per day, primarily due to expected natural declines. Further production decreases stemmed from the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 21 MMcf per day. Excluding the impact of the Boyer divestiture, our natural gas production would have been six percent lower than in 2011.



ROYALTIES

Royalties decreased $6 million in 2012 due to lower volumes in combination with lower prices. The average royalty rate in 2012 was 1.3 percent (2011 – 1.5 percent). Most of our natural gas production in the Conventional segment is located on fee land where we hold mineral rights which results in mineral tax recorded within production and mineral taxes.

Expenses

TRANSPORTATION

Transportation costs decreased $15 million due to lower production volumes.

OPERATING

Our operating expenses are composed largely of property taxes and lease costs, repairs and maintenance and workforce. Operating expenses decreased $25 million in 2012. The reduction in natural gas activity and the disposition of the Boyer property early in 2012 resulted in lower repairs and maintenance and workover activity costs.

RISK MANAGEMENT

Risk management activities resulted in realized gains in 2012 of $229 million (2011 – gains of $195 million) consistent with our 2012 contract prices exceeding the 2012 average benchmark price.

OPERATING CASH FLOW IN EXCESS OF CAPITAL INVESTMENT

Operating cash flow from natural gas in excess of capital investment decreased $184 million primarily due to lower operating cash flow partially offset by a $59 million reduction in capital investment.

CONVENTIONAL – CAPITAL INVESTMENT [(1)]

($ millions)	**2012**	2011	2010
Crude Oil and NGLs	**805**	686	363
Natural Gas	**43**	102	163
	848	788	526

(1) Includes expenditures on PP&E and E&E assets.

Capital investments in our Conventional segment focused on crude oil opportunities. Capital was invested in our tight oil drilling programs in Saskatchewan and southeast Alberta. In addition, drilling and facilities work continued in Weyburn. Spending on natural gas activities was reduced in response to low natural gas prices.

Crude oil and NGLs wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

Conventional Drilling Activity

(net wells, unless otherwise stated)	**2012**	2011	2010
Crude Oil and NGLs	**276**	325	180
Natural Gas	**–**	65	495
Recompletions	**977**	1,122	1,194
Gross Stratigraphic Test Wells	**14**	11	9

Subsequent to December 31, 2012, Management decided to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The public sales process is expected to be launched in late February 2013. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. Operating results from these properties are included in the Conventional segment.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against reduced crude oil prices by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors related to our Refining and Marketing segment in 2012 include:

- Increased total heavy crude oil processing capacity to between 235,000 to 255,000 barrels per day (dependent on the quality of heavy crude oil that is economically available) as a result of a full year of operations from the CORE project at the Wood River Refinery, enhancing our ability to further integrate our growing bitumen production;
- Our refineries processing 412,000 barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, resulting in 433,000 barrels per day of refined product output; and
- Strong refining margins, resulting from higher crack spreads and discounted crude oil feedstock costs.

REFINERY OPERATIONS [1]

	2012	2011	2010
Crude Oil Capacity *(Mbbls/d)*	**452**	452	452
Crude Oil Runs *(Mbbls/d)*	**412**	401	386
Heavy Oil	**198**	126	104
Light/Medium	**214**	275	282
Crude Utilization *(percent)*	**91**	89	86
Refined Products *(Mbbls/d)*	**433**	419	405
Gasoline	**216**	207	204
Distillate	**138**	132	124
Other	**79**	80	77

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

Refining operations in 2012 reflect the start-up of the CORE project in the fourth quarter of 2011, which has increased heavy crude oil runs and refined product output. On a 100 percent basis, our refineries had a capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 235,000 to 255,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy oil production.

Our crude utilization represents the percentage of crude oil, heavy and other, that is processed in our refineries relative to the total capacity. The amount of heavy crude oils processed, such as WCS and CDB, is dependent on the quality of available crude oils with the total crude input slate being optimized to maximize economic benefit. The amount of heavy crude processed increased by 72,000 barrels per day, a 57 percent increase.

Clean product yield is the percentage output of high value product from every barrel of inputs going into our refineries. Our clean product yield has increased as a result of the start-up of the CORE project which increased our processing capacity of blended heavy crude oil. Total refined product output increased by three percent over 2011 with the proportion of gasoline, distillate and other refined products remaining relatively the same.

FINANCIAL RESULTS

($ millions)	**2012**	2011	2010
Revenues	**11,356**	10,625	8,228
Purchased Product	**9,506**	9,149	7,674
Gross Margin	**1,850**	1,476	554
Expenses			
Operating	**587**	481	488
(Gain) Loss on Risk Management	**(4)**	14	(10)
Operating Cash Flow	**1,267**	981	76
Capital Investment	**118**	393	656
Operating Cash Flow in Excess (Deficient) of Capital Investment	**1,149**	588	(580)

Gross Margin

The gross margin for the Refining and Marketing segment increased $374 million in 2012 primarily due to improved refined product output from higher clean product yield at Wood River, higher refined products prices and lower feedstock costs from processing more discounted heavy crude oil as a result of a full year of operations after completion of the CORE project.

Operating

Total operating costs consist mainly of labour, maintenance, utilities and supplies. Operating costs for 2012 increased $106 million due to higher labour and maintenance expenses, consistent with higher utilization, as well as costs related to turnaround activities at both refineries in the fourth quarter. While there is an increase in utility usage at the Wood River Refinery subsequent to the CORE project start-up, utilities costs have declined at both refineries due to significantly lower prices for fuel gas and electricity.

Operating Cash Flow

Operating cash flow from the Refining and Marketing segment increased $286 million to $1,267 million in 2012 as a result of improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

REFINING AND MARKETING – CAPITAL INVESTMENT

($ millions)	**2012**	2011	2010
Wood River Refinery	**54**	346	568
Borger Refinery	**64**	45	87
Marketing	**–**	2	1
	118	393	656

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on the long-term power purchase contract. The unrealized gains on risk management were $57 million for the year ended December 31, 2012 (December 31, 2011 – gains of $180 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

GENERAL AND ADMINISTRATIVE AND FINANCING COSTS

($ millions)	**2012**	2011	2010
General and Administrative	**352**	295	246
Finance Costs	**455**	447	498
Interest Income	**(109)**	(124)	(144)
Foreign Exchange (Gain) Loss, net	**(20)**	26	(51)
(Gain) Loss on Divestiture of Assets	**–**	(107)	(116)
Other (Income) Loss, net	**(5)**	4	(13)
	673	541	420

Expenses

GENERAL AND ADMINISTRATIVE

General and administrative expenses increased $57 million in 2012 primarily due to the recruiting of new employees to fill positions created by our growth, which resulted in additional staffing and office support costs, including training and development, information technology and office space.

FINANCE COSTS

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In 2012, finance costs were $8 million higher than 2011 due to the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2012 was 5.3 percent (2011 – 5.5 percent).

INTEREST INCOME

Interest income primarily includes interest earned on our U.S. dollar denominated Partnership Contribution Receivable as well as short-term investments. Interest income in 2012 decreased by $15 million, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

FOREIGN EXCHANGE

For 2012, we recognized net foreign exchange gains of $20 million (2011 – losses $26 million) which includes unrealized gains of $70 million (2011 – unrealized gains of $42 million) and realized losses of $50 million (2011 – realized losses $68 million). The majority of unrealized gains are due to translation of our U.S. dollar denominated debt as a result of a stronger Canadian dollar at December 31, 2012.

DD&A

($ millions)	**2012**	2011	2010
Oil Sands	**482**	347	375
Conventional	**905**	778	799
Refining and Marketing	**146**	130	96
Corporate and Eliminations	**52**	40	32
	1,585	1,295	1,302

Oil Sands DD&A for 2012 increased $135 million due to higher sales volumes at Foster Creek, Christina Lake and Pelican Lake as well as increased DD&A rates due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment increased $127 million in 2012 due to higher crude oil sales volumes and increased DD&A rates due to higher future development costs associated with proved reserves, partially offset by reduced natural gas sales volumes.

Refining and Marketing DD&A increased $16 million in 2012 as the capital costs of the CORE project are now subject to depreciation.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

EXPLORATION EXPENSE

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability has been established are capitalized as E&E assets. If a field, project or area is determined to no longer be technically feasible or commercially viable and we decide not to continue the E&E activity, the unrecoverable costs are charged to exploration expense.

During 2012, $68 million of capitalized E&E costs, related primarily to the Roncott asset, a small exploration acreage within the Conventional segment, were deemed not to be commercially viable and technically feasible, and were recognized as exploration expense.

GOODWILL IMPAIRMENT

For the purpose of impairment testing, goodwill, which arose on the acquisition of exploration and production assets, is allocated to the CGU to which it relates. At December 31, 2012, Cenovus determined that the carrying amount of the Suffield CGU, including the allocated goodwill, exceeded its fair value less costs to sell resulting in an impairment loss of $393 million. The full amount of the impairment was attributed to goodwill. This goodwill arose in 2002 upon the formation of the predecessor corporation. The impairment resulted primarily due to a decline in natural gas and crude oil prices and increased operating costs. In addition, we have had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill, which is not subject to depreciation, depletion and amortization, exceeded its fair value.

INCOME TAX EXPENSE

($ millions)	**2012**	2011	2010
Current Tax			
Canada	**188**	150	82
U.S.	**121**	4	–
Total Current Tax	**309**	154	82
Deferred Tax	**474**	575	141
	783	729	223

In 2012, current taxes were higher due to increased cash flow from upstream operations taxed at Canadian rates, additional U.S. income tax from our refining operations and $68 million of withholding tax on the payment of a U.S. dividend. We did not have U.S. federal taxable income as we had sufficient deductions for 2012. U.S. current tax expense is much higher than 2011 because of higher state income tax, where certain loss deductions are deferred to future years for state tax purposes. The decrease in deferred tax is due to lower unrealized risk management gains, the reversal of certain taxable timing differences, partially offset by an increase in income from our refining operations.

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

($ millions, except percent amounts)	**2012**	2011	2010
Earnings Before Income Tax	**1,776**	2,207	1,304
Canadian Statutory Rate	**25.2%**	26.7%	28.2%
Expected Income Tax	**448**	589	368
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**146**	82	(22)
Non-deductible Stock-based Compensation	**10**	18	34
Multi-jurisdictional Financing	**(27)**	(50)	(93)
Foreign Exchange Gains (Losses) not Included in Net Earnings	**14**	(9)	28
Non-taxable Capital Gains	**(7)**	(8)	(13)
Recognition of Capital Losses	**(22)**	26	(107)
Adjustments Arising From Prior Year Tax Filings	**33**	31	26
Withholding Tax on Foreign Dividends	**68**	–	–
Goodwill Impairment	**99**	–	–
Other	**21**	50	2
Total Tax	**783**	729	223
Effective Tax Rate	**44.1%**	33.0%	17.1%

The Canadian statutory tax rate decreased to 25.2 percent as a result of tax legislation enacted in 2007. The U.S. statutory tax rate has increased to 38.5 percent as a result of the allocation of taxable income to U.S. states.

The increase in our effective tax rate in 2012 is primarily due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, the impairment of goodwill, U.S. withholding tax on the payment of a dividend in 2012 and lower benefits of multi-jurisdictional financing.

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 permanent differences into consideration, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Permanent differences include:

- Withholding tax on foreign dividends;
- Goodwill impairment;
- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. The effective rate for 2012 is higher than 2011 due to a change in the weighting of income between our U.S. and Canadian operations.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

QUARTERLY RESULTS

($ millions, except per share amounts)	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010
Production Volumes									
Crude Oil and NGLs *(bbls/d)*	**177,646**	**171,350**	**155,566**	**156,850**	144,273	133,496	121,762	137,355	129,593
Natural Gas *(MMcf/d)*	**566**	**577**	**596**	**636**	660	656	654	652	688
Revenues	**3,724**	**4,340**	**4,214**	**4,564**	4,329	3,858	4,009	3,500	3,363
Operating Cash Flow (1)	**963**	**1,310**	**1,078**	**1,085**	1,019	945	1,064	834	815
Cash Flow (1)	**697**	**1,117**	**925**	**904**	851	793	939	693	645
per Share – Diluted	**0.92**	**1.47**	**1.22**	**1.19**	1.12	1.05	1.24	0.91	0.85
Operating Earnings (Loss) (1)	**(189)**	**432**	**283**	**340**	332	303	395	209	147
per Share – Diluted	**(0.25)**	**0.57**	**0.37**	**0.45**	0.44	0.40	0.52	0.28	0.19
Net Earnings (Loss)	**(118)**	**289**	**396**	**426**	266	510	655	47	78
per Share – Basic	**(0.16)**	**0.38**	**0.52**	**0.56**	0.35	0.68	0.87	0.06	0.10
per Share – Diluted	**(0.16)**	**0.38**	**0.52**	**0.56**	0.35	0.67	0.86	0.06	0.10
Capital Investment (2)	**978**	**830**	**660**	**900**	903	631	476	713	701
Cash Dividends	**167**	**166**	**166**	**166**	151	150	151	151	151
per Share	**0.22**	**0.22**	**0.22**	**0.22**	0.20	0.20	0.20	0.20	0.20

(1) Non-GAAP measures defined in the Financial Results section of this MD&A.

(2) Includes expenditures on PP&E and E&E assets.

FOURTH QUARTER 2012 RESULTS OF OPERATIONS

In the fourth quarter, our financial results were negatively impacted by lower crude oil and natural gas prices, with significant decreases in crude oil benchmark prices in the month of December. The average WTI-WCS differential in December was US$30.37 per barrel as compared to US$11.72 per barrel for the same period last year. The fourth quarter was also impacted by a $393 million goodwill impairment charge, resulting primarily from the decline in future natural gas and crude oil prices and increased operating costs at our Suffield property within our Conventional segment. In addition, low refinery utilization as a result of planned turnaround activities, negatively impacted our financial results.

Realized price decreases were partially offset by crude oil and NGLs production increases of 23 percent, with the most significant increase at Christina Lake mainly due to phase C reaching full production capacity in the second quarter of 2012 and the start of production at phase D in the third quarter of 2012. In 2012, we achieved a new single day production high of 93,936 gross barrels at Christina Lake. At Narrows Lake we received final partner approval for the first phase.

Natural gas production in the fourth quarter of 2012 was 566 MMcf per day, a decrease of 14 percent from 2011, mainly due to expected declines in production from limited capital investment.

FOURTH QUARTER 2012 FINANCIAL RESULTS

Operating Cash Flow

Operating cash flow decreased $56 million in the fourth quarter of 2012, as compared to the same period in 2011, primarily due to:

- A decrease of $116 million in Refining and Marketing operating cash flow due to lower refinery utilization during planned turnarounds and higher operating costs related to those activities; and
- A 25 percent decrease in our average sales price of crude oil and NGLs to $60.13 per barrel, caused mainly by the increase in benchmark price differentials.

Partially offset by:

- Crude oil and NGLs sales volumes increasing 31 percent, primarily resulting from an increase in production volumes at Christina Lake;
- Realized risk management gains before tax, excluding Refining and Marketing, of $102 million compared to gains of $29 million in 2011; and
- A decrease in crude oil and NGLs royalties of 48 percent due mainly to an increase in capital investments.

Cash Flow

Our cash flow decreased $154 million in the fourth quarter of 2012 primarily due to decreases in operating cash flow as discussed above; and

- An increase in current tax expense, excluding tax on divestitures, of $74 million in the fourth quarter of 2012 primarily due to withholding tax on U.S. dividends.

Operating Earnings

Our operating earnings decreased $521 million in the fourth quarter of 2012 primarily due to:

- Goodwill impairment of $393 million in our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill exceeded its fair value;
- Decreased cash flow as discussed above; and
- Increased DD&A as a result of higher production and higher DD&A rates.

Partially offset by:

- A decrease in deferred income tax, excluding deferred tax on gains and losses on unrealized risk management, non-operating foreign exchange and divestitures of $20 million.

Net Earnings

In the fourth quarter of 2012, our net earnings decreased $384 million. The factors discussed above that decreased our operating earnings also impacted net earnings in addition to:

- No divestitures in 2012 as compared to an after-tax gain on divestiture of $89 million in the same period in 2011; and
- Unrealized foreign exchange losses in 2012 as compared to gains in 2011.

Partially offset by:

- Unrealized risk management gains, after-tax, of $87 million as compared to losses of $180 million in the fourth quarter of 2011.

Capital Investment

Capital investment in the fourth quarter of 2012 was $978 million, an increase of $75 million from the same period in 2011. The fourth quarter was busy with construction on three phases at Foster Creek, two phases at Christina Lake and our drilling and completions programs across the other areas.

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").

Our reserves are primarily located in Alberta and Saskatchewan, Canada. We retained two independent qualified reserves evaluators ("IQREs"), McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and CBM 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 crude oil and natural gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets independently with Management and with 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 provide a recommendation on approval of the reserves and resources disclosure to the Board.

Highlights in 2012 include:

- Proved bitumen reserves increased approximately 18 percent and proved plus probable reserves increased approximately 23 percent;
  - Regulatory approval for phases A, B and C, and partner approval for phase A of the Narrows Lake project added proved reserves of 222 million barrels and proved plus probable reserves of 359 million barrels, transitioning contingent resources to proved reserves;
  - Christina Lake added proved reserves of 41 million barrels while proved plus probable reserves increased by 42 million barrels. Increases at Christina Lake were a result of increasing well density through most of the project area and improving steam to oil ratio performance;
  - Foster Creek added proved reserves of 32 million barrels and proved plus probable reserves of 80 million barrels. Increases at Foster Creek were a result of improved recovery due to improving steam to oil ratio performance and more efficient drainage of bitumen in the steam chamber;
- Heavy oil proved reserves increased approximately five percent and proved plus probable reserves increased approximately two percent. These increases were a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves increased by approximately three percent, as a result of expanding waterflood and carbon dioxide flood areas at Weyburn;
- Natural gas proved reserves declined approximately 21 percent and proved plus probable reserves declined approximately 19 percent as reduced extensions and technical revisions from lower capital investment did not offset production and dispositions. Also included in the decline, is a loss of 58 Bcf of gas reserves due to lower gas prices in the forecast causing some gas reserves to become uneconomic to produce;
- Economic bitumen best estimate contingent resources increased 1.4 billion barrels or approximately 17 percent. This increase is a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources, the recognition of SAGD feasibility in the Wabiskaw formation adjacent to Foster Creek and the recognition of contingent resources on the acquired land near Telephone Lake; and
- Bitumen best estimate prospective resources declined 1.5 billion barrels or approximately 15 percent, as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling and the sterilization of lands through approval of the Lower Athabasca Regional Plan ("LARP").

The reserves and resources data that follows is presented as at December 31, 2012 using McDaniel's January 1, 2013 forecast prices and costs and comparative information as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

RESERVES AS AT DECEMBER 31

Before Royalties	Bitumen (MMbbls) 2012	Bitumen (MMbbls) 2011	Heavy Oil (MMbbls) 2012	Heavy Oil (MMbbls) 2011	Light & Medium Oil & NGLs (MMbbls) 2012	Light & Medium Oil & NGLs (MMbbls) 2011	Natural Gas & CBM (Bcf) 2012	Natural Gas & CBM (Bcf) 2011
Proved	**1,717**	1,455	**184**	175	**115**	115	**955**	1,203
Probable	**676**	490	**105**	109	**56**	51	**338**	391
Proved plus Probable	**2,393**	1,945	**289**	284	**171**	166	**1,293**	1,594

RECONCILIATION OF PROVED RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2011	**1,455**	**175**	**115**	**1,203**
Extensions and Improved Recovery	**265**	**17**	**13**	**29**
Discoveries	**–**	**–**	**–**	**–**
Technical Revisions	**30**	**6**	**(2)**	**51**
Economic Factors	**–**	**–**	**–**	**(58)**
Acquisitions	**–**	**–**	**1**	**1**
Dispositions	**–**	**–**	**–**	**(59)**
Production	**(33)**	**(14)**	**(12)**	**(212)**
December 31, 2012	**1,717**	**184**	**115**	**955**
Year Over Year Change	**262**	**9**	**–**	**(248)**
	18%	**5%**	**0%**	**(21%)**

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2011	**490**	**109**	**51**	**391**
Extensions and Improved Recovery	**140**	**11**	**5**	**8**
Discoveries	**–**	**–**	**–**	**–**
Technical Revisions	**46**	**(15)**	**–**	**(30)**
Economic Factors	**–**	**–**	**–**	**(4)**
Acquisitions	**–**	**–**	**–**	**–**
Dispositions	**–**	**–**	**–**	**(27)**
Production	**–**	**–**	**–**	**–**
December 31, 2012	**676**	**105**	**56**	**338**
Year Over Year Change	**186**	**(4)**	**5**	**(53)**
	38%	**(4%)**	**10%**	**(14%)**

ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES AS AT DECEMBER 31

(billions of barrels, before royalties)	Bitumen 2012	Bitumen 2011
Economic Contingent Resources (1)		
Low Estimate	**7.1**	6.0
Best Estimate	**9.6**	8.2
High Estimate	**12.8**	10.8
Prospective Resources (1)(2)		
Low Estimate	**5.0**	5.7
Best Estimate	**8.5**	10.0
High Estimate	**14.8**	17.9

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and low, best and high estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) 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.

Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican.

At Foster Creek and Christina Lake we have economic contingent resources located outside the currently approved development project areas. Regulatory approval of development project area expansion is necessary to enable the reclassification of these economic contingent resources as reserves. The rate at which we submit applications for development area expansion is dependent on the rate of development drilling, which ties to an orderly development plan that maximizes utilization of steam generation facilities and ultimately optimizes production, capital utilization and value.

In the Borealis Region we have submitted an application for a development project at the Telephone Lake property which, if approved, would enable the reclassification of certain economic contingent resources in the area to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity in order to submit regulatory applications for development projects. Stratigraphic test well drilling and seismic activity is continuing in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

In the Greater Pelican Region we submitted an application in the fourth quarter of 2011 for development project approval at the Grand Rapids property. Provided all regulatory requirements are met, we anticipate receiving regulatory approval in 2013. Pilot project work is underway to examine optimal development strategies.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, approval of the Narrows Lake project resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic test well program in the Borealis Region moved some prospective resources to contingent resources. The overall reduction to prospective resources is the expected outcome of a successful stratigraphic test well program, which converts undiscovered resources to discovered resources.

Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to continue to improve overall recovery from our bitumen assets as technology develops.

Information with respect to pricing as well as additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resource estimates, is contained in our AIF for the year ended December 31, 2012.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	**2012**	2011	2010
Net Cash From (Used In)			
Operating Activities	**3,420**	3,273	2,591
Investing Activities	**(3,336)**	(2,530)	(1,793)
Net Cash Provided before Financing Activities	**84**	743	798
Financing Activities	**592**	(558)	(631)
Foreign Exchange Gains (Losses) on Cash and Cash Equivalents Held in Foreign Currency	**(11)**	10	(22)
Increase in Cash and Cash Equivalents	**665**	195	145

OPERATING ACTIVITIES

Cash from operating activities was $147 million higher in 2012 mainly due to the $367 million increase in cash flow, partially offset by the net change in non-cash working capital. Cash flow is discussed in the Financial Results section of this MD&A. Cash from operating activities is also impacted by the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $1,043 million at December 31, 2012 compared to $283 million at December 31, 2011. We anticipate that we will continue to meet our payment obligations as they come due.

INVESTING ACTIVITIES

Cash used for investing activities in 2012 was $806 million higher than 2011. The increase is primarily due to higher capital expenditures of $3.4 billion in 2012. Capital expenditures are further discussed under Net Capital Investment within the Financial Results section and Capital Investment within the Reportable Segments section of this MD&A.

FINANCING ACTIVITIES

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend and finally to growth capital. In 2012, we paid a dividend of $0.88 per share (2011 – $0.80 per share).

Total dividend payments in 2012 were $665 million (2011 – $603 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash from financing activities in 2012 increased $1.15 billion as a result of the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by increased dividends paid and the repayment of short-term borrowings throughout the year.

Our long-term debt was $4,679 million at December 31, 2012 with no payments of principal due until September 2014 (US$800 million). We had cash and cash equivalents of $1,160 million at December 31, 2012. Long-term debt and cash and cash equivalents increased with the issuance of senior unsecured notes in 2012.

U.S. Senior Unsecured Notes

On August 17, 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00 percent due August 15, 2022 (10 year) and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042 (30 year). The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

AVAILABLE SOURCES OF LIQUIDITY

($ millions)	**Amount**	**Term**
Cash and Cash Equivalents	**1,160**	Not applicable
Committed Credit Facility	**3,000**	November 2016
Canadian Base Shelf Prospectus [1]	**1,500**	June 2014
U.S. Base Shelf Prospectus [1]	**US$ 750**	July 2014

(1) Availability is subject to market conditions.

As at December 31, 2012, we are in compliance with all of the terms of our debt agreements.

Committed Credit Facility

In September 2012, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and reducing both the standby fees to maintain the facility as well as the cost of future borrowings. We also have a commercial paper program which, together with the committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding. As of December 31, 2012, no amounts were drawn on our committed credit facility and there was no commercial paper outstanding.

Canadian Base Shelf Prospectus

On May 24, 2012, 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 issuance of medium-term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

U.S. Base Shelf Prospectus

On June 6, 2012, we filed a U.S. base shelf prospectus for senior unsecured notes in the amount of US$2.0 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 with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, US$750 million remains available under our U.S. base shelf prospectus. The U.S. base shelf prospectus expires in July 2014.

FINANCIAL METRICS

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairment, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

	2012	2011	2010
Debt to Capitalization	**32%**	27%	29%
Debt to Adjusted EBITDA *(times)*	**1.1x**	1.0x	1.3x

Debt to Capitalization is calculated as follows:

As at December 31,	**2012**	2011	2010
Debt	**4,679**	3,527	3,432
Shareholders' Equity	**9,806**	9,406	8,395
Capitalization	**14,485**	12,933	11,827
Debt to Capitalization	**32%**	27%	29%

The following is a reconciliation of Adjusted EBITDA and the calculation of Debt to Adjusted EBITDA:

As at December 31,	**2012**	2011	2010
Debt	**4,679**	3,527	3,432
Net Earnings	**993**	1,478	1,081
Add (Deduct):			
Finance Costs	**455**	447	498
Interest Income	**(109)**	(124)	(144)
Income Tax Expense	**783**	729	223
DD&A	**1,585**	1,295	1,302
Goodwill Impairment	**393**	–	–
Exploration Expense	**68**	–	–
Unrealized Gain on Risk Management	**(57)**	(180)	(46)
Foreign Exchange (Gain) Loss, net	**(20)**	26	(51)
(Gain) Loss on Divestiture of Assets	**–**	(107)	(116)
Other (Income) Loss, net	**(5)**	4	(13)
Adjusted EBITDA	**4,086**	3,568	2,734
Debt to Adjusted EBITDA	**1.1x**	1.0x	1.3x

We continue to have long-term targets for 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. At December 31, 2012, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

Our debt levels at December 31, 2012 were higher than at December 31, 2011 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter of 2012. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

OUTSTANDING SHARE DATA AND STOCK-BASED COMPENSATION PLANS

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. At December 31, 2012, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of Cenovus. Options issued by Cenovus prior to February 24, 2011, have associated tandem stock appreciation rights ("TSARs") and options issued after February 24, 2011 have associated net settlement rights ("NSRs").

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. DSUs vest immediately and are equivalent in value to a Cenovus common share on the date of redemption.

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSR's and PSU's are 1.42, 5.85 and 1.24 years, respectively.
See the notes to the Consolidated Financial Statements for details of our stock-based compensation plans.

Total Outstanding Common Shares and Stock-Based Compensation Plans

(thousands of units)	**December 31, 2012**
Common Shares	**755,843**
Stock Options	
NSRs	**15,074**
TSARs	**11,251**
Cenovus Replacement TSARs	**5,229**
Encana Replacement TSARs	**7,722**
Other Stock-Based Compensation Plans	
PSUs	**5,258**
DSUs	**1,084**

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The below contractual obligations have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise:

	Expected Payment Date						
($ millions)	2013	2014	2015	2016	2017	2018+	Total
Operating							
Pipeline Transportation (1)	145	209	378	403	675	8,130	9,940
Operating Leases (Building Leases)	109	106	112	110	104	1,602	2,143
Product Purchases	81	18	18	6	–	–	123
Other Long-term Commitments	32	25	18	7	6	10	98
Interest on Long-term Debt	254	252	216	216	216	3,120	4,274
Interest on Partnership Contribution Payable	100	76	51	25	2	–	254
Total Operating	721	686	793	767	1,003	12,862	16,832
Investing							
Capital Commitments (2)	320	54	61	53	6	2	496
Other Long-term Commitments	1	–	–	–	–	–	1
Decommissioning Liabilities	85	142	125	128	137	6,248	6,865
Total Investing	406	196	186	181	143	6,250	7,362
Financing							
Long-term Debt	–	796	–	–	–	3,930	4,726
Partnership Contribution Payable	386	410	435	462	120	–	1,813
Total Financing	386	1,206	435	462	120	3,930	6,539
Total Payments (3)	1,513	2,088	1,414	1,410	1,266	23,042	30,733
Fixed Price Product Sales	50	52	54	55	3	–	214
Partnership Contribution Receivable	471	471	471	471	118	–	2,002

(1) Certain transportation commitments included are subject to regulatory approval.

(2) Includes commitments related to joint operations.

(3) Contracts on behalf of the FCCL Partnership ("FCCL") and WRB Refining LP ("WRB") are reflected at our 50 percent interest.

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), debt, future building leases, marketing agreements and capital commitments. 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, 2012, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 49 Bcf of natural gas at a weighted average price of $4.38 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 a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

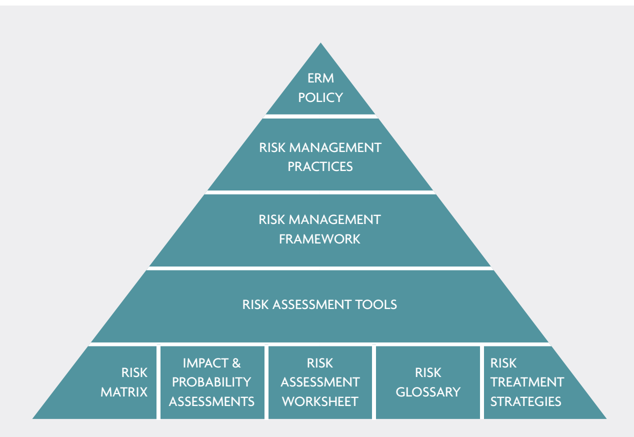
RISK MANAGEMENT

The Canadian Institute of Chartered Accountants issued new guidance in 2012, which suggested that corporate reporting would be enhanced with further disclosures of how companies approach and mitigate risks generally. Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others that are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk within our risk appetite ultimately determined by Management and confirmed by the Board.

RISK GOVERNANCE

Through our Enterprise Risk Management ("ERM") program, we have established a systematic process for identifying, measuring, prioritizing and managing risk across Cenovus.

The ERM Policy, approved by our Board, outlines our risk management principles and expectations as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Practices, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in their *ISO 31000 – Risk Management Principles and Guidelines*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through quarterly updates.



RISK ASSESSMENT

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized assessment tools.

Using the Risk Matrix, each risk is classified on a continuum ranging from "Marginal" to "Catastrophic" based on the potential impact and likelihood of occurrence. Risks are first evaluated on an inherent basis, without considering the presence of controls or mitigating measures. Risks are then re-evaluated based on their residual risk ranking, reflecting the risk that remains after mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking and there are prescribed actions for elevating these exposures to the right decision makers.

RISK MANAGEMENT ROLES AND RESPONSIBILITIES

The roles and responsibilities of the various participants of our ERM Program are:

Board:

- Oversees the implementation of the ERM program by Management and provides oversight for risk management activities; and
- The Audit Committee of the Board reviews our Risk Management Framework and related processes on an annual basis to ensure processes remain current and relevant.

Senior Management:

- Confirms our corporate risk appetite with the Board. The executive team is interviewed annually and collaborative workshops are held with SVP's and VP's to support the development of the Annual Risk Report.

The Financial & Enterprise Risk Team reports to the Executive Vice President & Chief Financial Officer and is responsible for managing our ERM program and the related risk reporting.

PRINCIPAL AND STRATEGIC RISKS

Cenovus's operations, financial condition and in some cases our reputation, may be impacted by principal and strategic risks. Cenovus defines principal risks as those risks that when measured in terms of likelihood and impact, may adversely affect the achievement of our strategic or major business objectives. Strategic risk is the risk of loss resulting from the inability to adequately plan or implement an appropriate business strategy, or to adapt to changes in the external business, political or regulatory environment.

Principal and strategic risks are categorized into:

- Financial risks, which includes commodity price risk and liquidity risk;
- Operational risks such as risks related to safety, the environment, transportation restrictions, project execution and reserves replacement; and
- Regulatory risks from the regulatory approval process and changes to or introduction of environmental regulations.

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2012.

The following is a discussion of how some of the material principal and strategic risks impact our business:

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit is managed through our Board approved credit policy.

COMMODITY PRICE RISK

Fluctuations in future commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints and alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

Changes in future commodity prices will affect the revenue generated by the sale of our crude oil, NGLs, natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

We anticipate commodity prices and refining margins will continue to be volatile over the next few years. If crude oil and natural gas prices decline significantly and remained at low levels for an extended period of time, the carrying value of our assets may be subject to impairment, future capital programs could be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations.

We manage our commodity price exposure through a combination of activities including integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations.

We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts. These transactions protect a portion of the budgeted cash flow and ensure funds are available for capital projects. These activities are reviewed and approved by the Risk Management Committee which is comprised of the President & Chief Executive Officer, Executive Vice President & Chief Financial Officer and one other EVP. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits. We have partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Widening location or quality differentials for crude oil and natural gas with fixed price differential and basis swaps; and
- Electricity consumption costs through a derivative power contract.

The details of these financial instruments as at December 31, 2012 are disclosed in the notes to the Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2012			2011		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil and NGLs	**81**	**247**	**328**	(135)	106	(29)
Natural Gas	**247**	**(176)**	**71**	210	38	248
Refining	**7**	**1**	**8**	(14)	7	(7)
Power	**1**	**(15)**	**(14)**	7	29	36
Gains (Losses) on Risk Management	**336**	**57**	**393**	68	180	248
Income Tax Expense	**86**	**14**	**100**	17	46	63
Gains (Losses) on Risk Management, after-tax	**250**	**43**	**293**	51	134	185

In 2012, our strategy to manage commodity price risk resulted in realized gains on both crude oil and natural gas financial instruments as contract benchmark commodity prices settled below our contract prices. We recognized unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices and the widening of light/heavy differentials at the end of 2012 compared to our contract prices. Natural gas financial instruments incurred unrealized losses as a result of increasing forward natural gas commodity prices. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We recognize that on an integrated basis, we have a long position in refined products which has become more strongly correlated to Brent crude rather than WTI. To better align our corporate risk management program with this exposure, we converted all existing 2013 WTI crude oil financial instruments to Brent pricing during 2012. In addition, 17,000 barrels per day were executed through financial instruments at fixed Brent pricing, resulting in a total of 37,000 barrels per day locked into a weighted average Brent price of US$111.32 per barrel.

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) for the year impacting earnings before income tax on open risk management positions as at December 31, 2012 as follows:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent & WTI Hedges	**(156)**	**156**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	**111**	**(111)**
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX Natural Gas Hedges	**(55)**	**55**
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	**1**	**(1)**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**

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. In depressed economic times or due to unforeseen events, Cenovus's liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows and reputation.

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, 2012, we had cash and cash equivalents of $1.2 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$750 million in unused capacity under our U.S. base shelf prospectus, the availability of which are dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term from unforeseen economic events that could create further volatility in cash flow.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that could impact the achievement of our objectives.

SAFETY RISK

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury. The inability to operate safely has the potential to have a material adverse impact on Cenovus's reputation, financial condition, results of operations and cash flow.

We are committed to safety in our operations. We take an active role with our refining partner in ensuring safety is the first priority. Our safety policies and standards comply with government regulations and industry standards. To partially mitigate safety risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System to identify, assess and control safety, security and environmental risk across our operations. In order to ensure we engage contractors who share the same commitment to safety, Cenovus uses a third party online safety prequalification system and safety performance data management tool. Prevention of occupational diseases and illnesses is also an integral part of our health and safety focus. We take a risk-based approach to systematically identify, evaluate, and manage health hazards of all workers at our sites.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies for approval by our Board and oversees compliance with government laws and regulations.

TRANSPORTATION RESTRICTIONS

Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower realized prices at specific locations or for specific grades and, in extreme situations, production curtailment. While this risk may impact our natural gas production, it has the greatest potential to impact our crude oil production, which could negatively affect our financial position, results of operations and cash flows within our Oil Sands and Conventional segments.

To help mitigate these risks, we employ a diversified sales strategy which includes sales at multiple market hubs to a variety of creditworthy counterparties utilizing multiple transportation options. In addition, we support and are prepared to commit to new and expanding transportation infrastructure with access to additional markets for our production, including cargo and railcar transportation methods.

We anticipate transportation constraints will continue in the near term. The Keystone XL project and the Northern Gateway Pipeline project, if approved, will benefit heavy oil producers. The Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Northern Gateway pipeline project in its current form will connect Alberta's oil sands to the western Canada coast, allowing for transportation to new markets, such as Asia. Other industry options are being developed and we are actively participating in those developments.

CAPITAL PROJECT EXECUTION AND OPERATING RISK

There are risks associated with the execution and operations of our upstream and refining projects. Over the next 10 years, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations and availability of skilled labour, key components or other scarce resources, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures.

Operational risks affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. Our operational risks include, but are not limited to safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, phased growth execution of oil sands projects and partner risks. We attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

RESERVES REPLACEMENT RISK

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. Our financial position, results of operations and cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

To mitigate the risk associated with replacing reserves, we evaluate projects on a fully risked basis including geological risk and engineering risk. In addition, our asset teams undertake a project look-back process, whereby each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results and are incorporated into the current year's plan. On an annual basis, look-back results are analyzed in relation to our capital program, with the results and identified learnings shared across our company.

To date our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our 10 year strategic plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2012.

ENVIRONMENTAL RISK

Developing and operating our projects is subject to hazards of recovering, transporting and processing hydrocarbons which can cause damage to the environment. We take our responsibility for the environment very seriously. To manage these risks, we strive to use, recycle and dispose of water safely, manage air emissions, limit our physical footprint and minimize our impact on habitat, including wildlife. Working with our stakeholders, we identify the unique needs of the different areas where we operate. Employees, contractors and third-party service providers receive the appropriate training they need to comply with regulations and be responsible environmental stewards. Our environmental impact is measured using the Cenovus Operations Management System to monitor, manage and accurately report our activities.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, 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, have been designed to provide assurance that environmental and regulatory standards are met. Contingency plans have been put in place for a timely response to an environmental event and remediation/reclamation programs have been put in place and utilized to restore the environment.

Regulatory Risk

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for a crude oil or natural gas development project. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as impose a cost of compliance, adversely impacting our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION RISK

The complexities of changes in environmental regulation make it difficult to predict the potential future impact to Cenovus. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. However, we expect that the cost of meeting new environmental and climate change regulations will not be so high as to cause a material disadvantage to our competitive position. Non-compliance with environmental regulations could also have an adverse impact on Cenovus's reputation.

Further discussion on specific areas that currently have, and are reasonably likely to have, an impact on Cenovus's operations is below.

Water Use Impacts

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements under these licenses reduces the amount of water available for our use, our production could decline or operating costs could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

Greenhouse Gases & Air Pollutants

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. A number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in Canada and the U.S.

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating costs and reduce demand for crude oil, natural gas 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.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. We incorporate the potential costs of carbon, ranging from \$15-\$65 per tonne of CO_2, into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

Land Use, Habitat and Biodiversity

Alberta's Land-Use Framework has been implemented under the Alberta Land Stewardship Act ("ALSA") which 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. In some cases, ALSA amends or extinguishes 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. On August 22, 2012, the Government of Alberta approved its LARP, which was issued under the ALSA, and came into effect on September 1, 2012.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Some of our Oil Sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted limiting the pace of development due to environmental limits and thresholds. The areas identified have no direct impact on our strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

We are required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING JUDGMENTS IN APPLYING ACCOUNTING POLICIES

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in Cenovus's Consolidated Financial Statements.

Exploration and Evaluation Assets

The application of Cenovus's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is no longer technically feasible or commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Cenovus's upstream and refining assets are grouped into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Cenovus's upstream, refining and corporate assets are assessed at the CGU level and therefore could have a significant impact on impairment losses.

KEY SOURCES OF ESTIMATION UNCERTAINTY

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Reserves

There are a number of inherent uncertainties associated with estimating reserves. Reserve estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserve estimates which would have a significant impact on the impairment test and depreciation, depletion and amortization expense of Cenovus's crude oil and natural gas assets. Cenovus's crude oil and natural gas reserves are evaluated and reported to us by independent qualified reserves evaluators.

Impairment of Assets

Property, plant and equipment, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, transportation capacity and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

At December 31, 2012, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs to sell. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

OIL AND NATURAL GAS PRICES

The future prices used to determine cash flows from oil and gas reserves are as follows:

	2013	2014	2015	2016	2017	Average Annual Percent Change to 2024
WTI *(US$/barrel)*	92.50	92.50	93.60	95.50	97.40	2%
AECO *($/Mcf)*	3.35	3.85	4.35	4.70	5.10	3%

DISCOUNT RATE

Evaluations of discounted future cash flow generally use, as a starting point, the discount rate of 10 percent which is an industry standard rate used by independent qualified reserve evaluators in preparing their reserve reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of Cenovus's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. During the year ended December 31, 2012, the decommissioning liability increased $417 million as a result of changes in the discount rate, the timing of settlement and the estimated costs that will arise on settlement. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As a result, there are usually a number of tax matters under review. As such, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

CHANGES IN ACCOUNTING POLICIES AND FUTURE ACCOUNTING PRONOUNCEMENTS

During the year ended December 31, 2012, Cenovus did not adopt any new accounting policies.

The following summarizes the future accounting pronouncements that will impact Cenovus. We will adopt each of the following accounting pronouncements on the effective date. Unless otherwise stated below, the impact of the initial application of the standards listed was not known or reasonably estimable at the time of authorization of the Consolidated Financial Statements.

Joint Arrangements, Consolidation, Associates and Disclosures

In May 2011, the International Accounting Standards Board ("IASB") issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control to include three elements: (1) power over an investee, (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.
- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". Under IFRS 11, a joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.
- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31 and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10, but retains the current guidance for separate financial statements.
- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. It is anticipated that the application of these five standards will not have a significant impact on the Consolidated Financial Statements.

Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of Cenovus's accounting policy under IFRS 11 requires judgment in determining the classification of its joint arrangements. It was determined that Cenovus has rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements will be classified as joint operations under IFRS 11 and Cenovus's share of the assets, liabilities, revenues and expenses will be recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, Cenovus considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The Partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Employee Benefits

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendments require the recognition of changes in defined benefit obligations and fair value of plan assets when they occur, eliminating the 'corridor approach', and accelerates the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are to be recognized immediately through Other Comprehensive Income ("OCI"). In addition, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendments also enhance financial statement disclosures.

The amendments to IAS 19 require retrospective application. Based on Cenovus's preliminary assessment, when the amendments are applied for the first time for the year ending December 31, 2013, net earnings for the year ended December 31, 2012 would increase $1 million and other comprehensive income after tax would decrease by $3 million (2011 – $nil and decrease $12 million, respectively). Shareholders' equity as at December 31, 2012 would decrease $24 million (January 1, 2012 – decrease $22 million) with corresponding adjustments being recognized in other liabilities and deferred income tax liability.

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. IFRS 13 will not have a significant impact on the Consolidated Financial Statements.

Financial Instruments

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. Cenovus is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The adoption of this amendment will not have a significant impact on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures*" ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar arrangements.
- IAS 32, "*Financial Instruments: Presentation*" ("IAS 32"), has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. It is anticipated that IFRS 7 and IAS 32 will not have significant impacts on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2012. Based on their evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2012.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2012.

There have been no changes to ICFR during the year ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, ICFR.

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.

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 continues to drive our commitments, strategy and reporting, and 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 is available on our website at www.cenovus.com.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We will not compromise the health and safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the CR policy includes reference to emergency response management, investment in efficiency projects, new technologies and research and support of the principles of the Universal Declaration of Human Rights.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. Our Corporate Responsibility Report can be found on our website at www.cenovus.com. This report was aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

In September 2012, we were named to the Dow Jones Sustainability World Index ("DJSI World") for the first time and to the Dow Jones Sustainability North America Index for the third year in a row. We were the only Canadian integrated oil and gas company listed to the DJSI World in 2012. DJSI World recognizes the top 10 percent of the 2,500 largest companies in the Dow Jones Global Total Stock Market Index that lead the field in terms of corporate responsibility performance. In October 2012, for the third year in a row, Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. In January 2013, we were named for the first time to the Corporate Knights Global 100 list for 2013, which recognizes the world's most sustainable corporations.

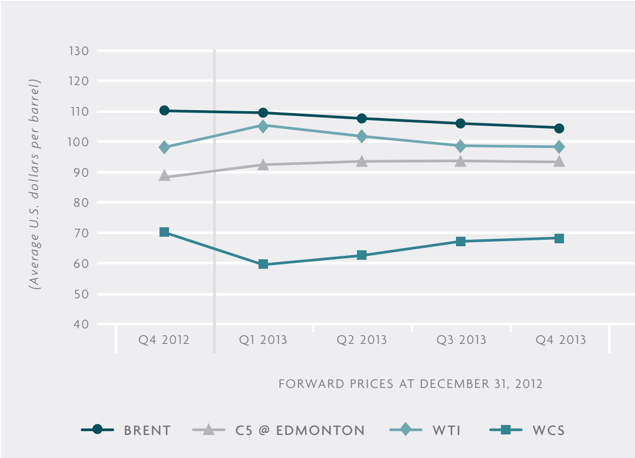
OUTLOOK

We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Grand Rapids and Telephone Lake. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Our crude oil pricing outlook is influenced by the following:

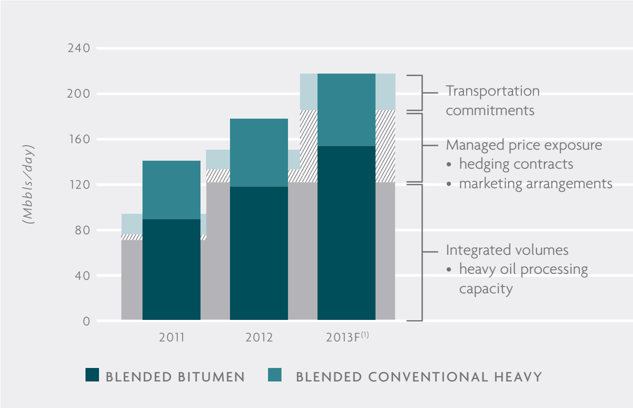
- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. Short-term prices are likely to remain volatile and be impacted by market expectations;
- Brent-WTI differentials are expected to narrow over the first half of 2013 as new pipeline capacity is added to move crude oil from Cushing to U.S. Gulf Coast markets;
- WCS prices should weaken relative to U.S. Gulf Coast pricing as inland crude oil supply continues to grow at a faster pace than rail and pipeline takeaway capacity. Although all WCSB crude oil should show downward price pressure, heavy grades should perform somewhat better in the latter half of 2013 once new coking capacity is added in the U.S. Midwest;
- Refining crack margins are projected to soften in 2013 when new pipeline capacity out of Cushing should cause WTI crude oil discounts to moderate. Refiners processing WCSB crude oil should continue to see strong margins; and
- Natural gas prices should continue to firm, provided weather remains near historic norms, as supply growth moderates with reduced activity and demand growth continues due to still very competitive North American gas pricing.



While we expect to see volatility in crude prices we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products which are closely tied to Brent pricing;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Congestion



(1) Expected gross production capacity

KEY PRIORITIES FOR 2013

Market Access

We are focused on near and mid-term strategies to broaden market access for Canadian oil. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. This will include increasing our rail shipping capacity for oil to approximately 10,000 barrels per day, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil.

Attacking Cost Structures

We have a track record of cost efficiency. To continue to meet our business plan, we must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we have a number of opportunities to improve our cost efficiency by further leveraging our supply chain management to improve capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans including timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A. We also direct our shareholders to review the guidance for 2013 that we published on our website, www.cenovus.com, in connection with our December 2012 news release.

CAPITAL ALLOCATION IN THE FUTURE

We will continue to develop our strategy with respect to capital investment and returns to shareholders. We believe that strong operational performance will translate into solid financial performance. Future cash flow will continue to be allocated using a disciplined approached, focusing on the following priorities:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow.

Future dividends are at the sole discretion of the Board and considered quarterly.

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board 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 on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public 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, 2012. 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 December 31, 2012.

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, 2012, as stated in their Auditor's Report dated February 13, 2013. PricewaterhouseCoopers LLP has provided such opinions.

BRIAN C. FERGUSON
President &
Chief Executive Officer
Cenovus Energy Inc.

February 13, 2013

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

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CENOVUS ENERGY INC.

We have completed an integrated audit of Cenovus Energy Inc.'s 2012 and 2011 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2012 and an audit of its 2010 Consolidated Financial Statements. 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 as at December 31, 2012 and December 31, 2011 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, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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 International Financial Reporting Standards as issued by the International Accounting Standards Board 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 about 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 auditor's 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, 2012 and December 31, 2011 and its financial performance and cash flows for each of the three years in the period ended December 31, 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2012, 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

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 Report of Management.

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

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, 2012 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP

Chartered Accountants
Calgary, Alberta, Canada

February 13, 2013

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, ($ millions, except per share amounts)	Notes	**2012**	2011	2010
Revenues	1			
Gross Sales		**17,229**	16,185	13,090
Less: Royalties		**387**	489	449
		16,842	15,696	12,641
Expenses	1			
Purchased Product		**9,223**	9,090	7,551
Transportation and Blending		**1,798**	1,369	1,065
Operating		**1,682**	1,406	1,286
Production and Mineral Taxes		**37**	36	34
(Gain) Loss on Risk Management	31	**(393)**	(248)	(324)
Depreciation, Depletion and Amortization	16	**1,585**	1,295	1,302
Goodwill Impairment	19	**393**	–	–
Exploration Expense	15	**68**	–	3
General and Administrative		**352**	295	246
Finance Costs	5	**455**	447	498
Interest Income	6	**(109)**	(124)	(144)
Foreign Exchange (Gain) Loss, net	7	**(20)**	26	(51)
(Gain) Loss on Divestiture of Assets	17	**–**	(107)	(116)
Other (Income) Loss, net		**(5)**	4	(13)
Earnings Before Income Tax		**1,776**	2,207	1,304
Income Tax Expense	8	**783**	729	223
Net Earnings		**993**	1,478	1,081
Other Comprehensive Income (Loss), Net of Tax				
Foreign Currency Translation Adjustment		**(24)**	48	71
Comprehensive Income		**969**	1,526	1,152
Net Earnings per Common Share	9			
Basic		**$ 1.31**	$ 1.96	$ 1.44
Diluted		**$ 1.31**	$ 1.95	$ 1.43

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31, *($ millions)*	Notes	**2012**	2011
Assets			
Current Assets			
Cash and Cash Equivalents	10	**1,160**	495
Accounts Receivable and Accrued Revenues	11	**1,464**	1,405
Current Portion of Partnership Contribution Receivable	12	**384**	372
Inventories	13	**1,288**	1,291
Risk Management	31	**283**	232
Assets Held for Sale	14	**–**	116
Current Assets		**4,579**	3,911
Exploration and Evaluation Assets	1, 15	**1,285**	880
Property, Plant and Equipment, net	1, 16	**16,152**	14,324
Partnership Contribution Receivable	12	**1,398**	1,822
Risk Management	31	**5**	52
Income Tax Receivable		**–**	29
Other Assets	18	**58**	44
Goodwill	1, 19	**739**	1,132
Total Assets		**24,216**	22,194
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	20	**2,650**	2,579
Income Tax Payable		**217**	329
Current Portion of Partnership Contribution Payable	12	**386**	372
Risk Management	31	**17**	54
Liabilities Related to Assets Held for Sale	14	**–**	54
Current Liabilities		**3,270**	3,388
Long-Term Debt	21	**4,679**	3,527
Partnership Contribution Payable	12	**1,426**	1,853
Risk Management	31	**1**	14
Decommissioning Liabilities	22	**2,315**	1,777
Other Liabilities	23	**151**	128
Deferred Income Taxes	8	**2,568**	2,101
Total Liabilities		**14,410**	12,788
Shareholders' Equity		**9,806**	9,406
Total Liabilities and Shareholders' Equity		**24,216**	22,194

Commitments and Contingencies 33

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

MICHAEL A. GRANDIN
Director
Cenovus Energy Inc.

COLIN TAYLOR
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)	Share Capital (Note 25)	Paid in Surplus (Note 25)	Retained Earnings	AOCI [1]	Total
Balance as at January 1, 2010	3,681	4,083	45	–	7,809
Net Earnings	–	–	1,081	–	1,081
Other Comprehensive Income (Loss)	–	–	–	71	71
Total Comprehensive Income for the Year	–	–	1,081	71	1,152
Common Shares Issued Under Option Plans	35	–	–	–	35
Dividends on Common Shares	–	–	(601)	–	(601)
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net Earnings	–	–	1,478	–	1,478
Other Comprehensive Income (Loss)	–	–	–	48	48
Total Comprehensive Income for the Year	–	–	1,478	48	1,526
Common Shares Issued Under Option Plans	64	–	–	–	64
Stock-Based Compensation Expense	–	24	–	–	24
Dividends on Common Shares	–	–	(603)	–	(603)
Balance as at December 31, 2011	3,780	4,107	1,400	119	9,406
Net Earnings	–	–	993	–	993
Other Comprehensive Income (Loss)	–	–	–	(24)	(24)
Total Comprehensive Income for the Year	–	–	993	(24)	969
Common Shares Issued Under Option Plans	49	–	–	–	49
Stock-Based Compensation Expense	–	47	–	–	47
Dividends on Common Shares	–	–	(665)	–	(665)
Balance as at December 31, 2012	**3,829**	**4,154**	**1,728**	**95**	**9,806**

(1) Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, *($ millions)*	Notes	2012	2011	2010
Operating Activities				
Net Earnings		**993**	1,478	1,081
Depreciation, Depletion and Amortization		**1,585**	1,295	1,302
Goodwill Impairment		**393**	–	–
Exploration Expense		**68**	–	–
Deferred Income Taxes	8	**474**	575	141
Cash Tax on Divestiture of Assets		**–**	13	–
Unrealized (Gain) Loss on Risk Management	31	**(57)**	(180)	(46)
Unrealized Foreign Exchange (Gain) Loss	7	**(70)**	(42)	(69)
(Gain) Loss on Divestiture of Assets	17	**–**	(107)	(116)
Unwinding of Discount on Decommissioning Liabilities	5, 22	**86**	75	75
Other		**171**	169	44
		3,643	3,276	2,412
Net Change in Other Assets and Liabilities		**(113)**	(82)	(55)
Net Change in Non-Cash Working Capital		**(110)**	79	234
Cash From Operating Activities		**3,420**	3,273	2,591
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	15	**(654)**	(527)	(350)
Capital Expenditures – Property, Plant and Equipment	16	**(2,795)**	(2,265)	(1,851)
Proceeds From Divestiture of Assets		**76**	173	309
Cash Tax on Divestiture of Assets		**–**	(13)	–
Net Change in Investments and Other		**(13)**	(28)	4
Net Change in Non-Cash Working Capital		**50**	130	95
Cash (Used in) Investing Activities		**(3,336)**	(2,530)	(1,793)
Net Cash Provided (Used) before Financing Activities		**84**	743	798
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**3**	(9)	–
Net Issuance (Repayment) of Revolving Long-Term Debt		**–**	–	(58)
Issuance of Long-Term Debt		**1,219**	–	–
Proceeds on Issuance of Common Shares		**37**	48	28
Dividends Paid on Common Shares	9	**(665)**	(603)	(601)
Other		**(2)**	6	–
Cash From (Used in) Financing Activities		**592**	(558)	(631)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(11)**	10	(22)
Increase (Decrease) in Cash and Cash Equivalents		**665**	195	145
Cash and Cash Equivalents, Beginning of Year		**495**	300	155
Cash and Cash Equivalents, End of Year		**1,160**	495	300

Supplementary Cash Flow Information 32

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2012

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc., and its subsidiaries, (together "Cenovus" or the "Company") are 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.").

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.

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of presentation for these Consolidated Financial Statements is found in Note 2.

The Company's reportable segments are as follows:

- **Oil Sands**, includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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 Phillips 66, an unrelated U.S. public company. 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 and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, 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 tabular financial information which follows presents the segmented information first by segment, then by product and geographic location.

A) RESULTS OF OPERATIONS – SEGMENT AND OPERATIONAL INFORMATION

	Oil Sands			Conventional			Refining and Marketing		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**4,088**	3,291	2,702	**2,068**	2,328	2,284	**11,356**	10,625	8,228
Less: Royalties	**215**	284	279	**172**	205	170	**–**	–	–
	3,873	3,007	2,423	**1,896**	2,123	2,114	**11,356**	10,625	8,228
Expenses									
Purchased Product	**–**	–	–	**–**	–	–	**9,506**	9,149	7,674
Transportation and Blending	**1,653**	1,231	935	**145**	138	130	**–**	–	–
Operating	**584**	438	367	**513**	488	434	**587**	481	488
Production and Mineral Taxes	**–**	–	–	**37**	36	34	**–**	–	–
(Gain) Loss on Risk Management	**(80)**	70	(10)	**(252)**	(152)	(258)	**(4)**	14	(10)
Operating Cash Flow	**1,716**	1,268	1,131	**1,453**	1,613	1,774	**1,267**	981	76
Depreciation, Depletion and Amortization	**482**	347	375	**905**	778	799	**146**	130	96
Goodwill Impairment	**–**	–	–	**393**	–	–	**–**	–	–
Exploration Expense	**–**	–	3	**68**	–	–	**–**	–	–
Segment Income (Loss)	**1,234**	921	753	**87**	835	975	**1,121**	851	(20)

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Revenues						
Gross Sales	**(283)**	(59)	(124)	**17,229**	16,185	13,090
Less: Royalties	**–**	–	–	**387**	489	449
	(283)	(59)	(124)	**16,842**	15,696	12,641
Expenses						
Purchased Product	**(283)**	(59)	(123)	**9,223**	9,090	7,551
Transportation and Blending	**–**	–	–	**1,798**	1,369	1,065
Operating	**(2)**	(1)	(3)	**1,682**	1,406	1,286
Production and Mineral Taxes	**–**	–	–	**37**	36	34
(Gain) Loss on Risk Management	**(57)**	(180)	(46)	**(393)**	(248)	(324)
	59	181	48	**4,495**	4,043	3,029
Depreciation, Depletion and Amortization	**52**	40	32	**1,585**	1,295	1,302
Goodwill Impairment	**–**	–	–	**393**	–	–
Exploration Expense	**–**	–	–	**68**	–	3
Segment Income (Loss)	**7**	141	16	**2,449**	2,748	1,724
General and Administrative	**352**	295	246	**352**	295	246
Finance Costs	**455**	447	498	**455**	447	498
Interest Income	**(109)**	(124)	(144)	**(109)**	(124)	(144)
Foreign Exchange (Gain) Loss, net	**(20)**	26	(51)	**(20)**	26	(51)
(Gain) Loss on Divestiture of Assets	**–**	(107)	(116)	**–**	(107)	(116)
Other (Income) Loss, net	**(5)**	4	(13)	**(5)**	4	(13)
	673	541	420	**673**	541	420
Earnings Before Income Tax				**1,776**	2,207	1,304
Income Tax Expense				**783**	729	223
Net Earnings				**993**	1,478	1,081

B) FINANCIAL RESULTS BY UPSTREAM PRODUCT

	Crude Oil and NGLs								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**4,037**	3,217	2,610	**1,559**	1,492	1,229	**5,596**	4,709	3,839
Less: Royalties	**215**	282	276	**166**	193	153	**381**	475	429
	3,822	2,935	2,334	**1,393**	1,299	1,076	**5,215**	4,234	3,410
Expenses									
Transportation and Blending	**1,651**	1,229	934	**126**	104	86	**1,777**	1,333	1,020
Operating	**548**	409	339	**294**	244	199	**842**	653	538
Production and Mineral Taxes	**–**	–	–	**34**	27	28	**34**	27	28
(Gain) Loss on Risk Management	**(62)**	87	14	**(23)**	43	5	**(85)**	130	19
Operating Cash Flow	**1,685**	1,210	1,047	**962**	881	758	**2,647**	2,091	1,805

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**40**	63	78	**496**	825	1,042	**536**	888	1,120
Less: Royalties	**–**	2	1	**6**	12	17	**6**	14	18
	40	61	77	**490**	813	1,025	**530**	874	1,102
Expenses									
Transportation and Blending	**2**	2	1	**19**	34	44	**21**	36	45
Operating	**25**	24	23	**215**	240	231	**240**	264	254
Production and Mineral Taxes	**–**	–	–	**3**	9	6	**3**	9	6
(Gain) Loss on Risk Management	**(18)**	(17)	(24)	**(229)**	(195)	(263)	**(247)**	(212)	(287)
Operating Cash Flow	**31**	52	77	**482**	725	1,007	**513**	777	1,084

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**11**	11	14	**13**	11	13	**24**	22	27
Less: Royalties	**–**	–	2	**–**	–	–	**–**	–	2
	11	11	12	**13**	11	13	**24**	22	25
Expenses									
Transportation and Blending	**–**	–	–	**–**	–	–	**–**	–	–
Operating	**11**	5	5	**4**	4	4	**15**	9	9
Production and Mineral Taxes	**–**	–	–	**–**	–	–	**–**	–	–
(Gain) Loss on Risk Management	**–**	–	–	**–**	–	–	**–**	–	–
Operating Cash Flow	**–**	6	7	**9**	7	9	**9**	13	16

	Total Upstream								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**4,088**	3,291	2,702	**2,068**	2,328	2,284	**6,156**	5,619	4,986
Less: Royalties	**215**	284	279	**172**	205	170	**387**	489	449
	3,873	3,007	2,423	**1,896**	2,123	2,114	**5,769**	5,130	4,537
Expenses									
Transportation and Blending	**1,653**	1,231	935	**145**	138	130	**1,798**	1,369	1,065
Operating	**584**	438	367	**513**	488	434	**1,097**	926	801
Production and Mineral Taxes	**–**	–	–	**37**	36	34	**37**	36	34
(Gain) Loss on Risk Management	**(80)**	70	(10)	**(252)**	(152)	(258)	**(332)**	(82)	(268)
Operating Cash Flow	**1,716**	1,268	1,131	**1,453**	1,613	1,774	**3,169**	2,881	2,905

C) GEOGRAPHIC INFORMATION

For the years ended December 31,	Canada			United States			Consolidated		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Revenues									
Gross Sales	**8,069**	7,513	6,466	**9,160**	8,672	6,624	**17,229**	16,185	13,090
Less: Royalties	**387**	489	449	**–**	–	–	**387**	489	449
	7,682	7,024	6,017	**9,160**	8,672	6,624	**16,842**	15,696	12,641
Expenses									
Purchased Product	**1,884**	1,867	1,456	**7,339**	7,223	6,095	**9,223**	9,090	7,551
Transportation and Blending	**1,798**	1,369	1,065	**–**	–	–	**1,798**	1,369	1,065
Operating	**1,118**	947	814	**564**	459	472	**1,682**	1,406	1,286
Production and Mineral Taxes	**37**	36	34	**–**	–	–	**37**	36	34
(Gain) Loss on Risk Management	**(385)**	(255)	(322)	**(8)**	7	(2)	**(393)**	(248)	(324)
	3,230	3,060	2,970	**1,265**	983	59	**4,495**	4,043	3,029
Depreciation, Depletion and Amortization	**1,439**	1,165	1,216	**146**	130	86	**1,585**	1,295	1,302
Goodwill Impairment	**393**	–	–	**–**	–	–	**393**	–	–
Exploration Expense	**68**	–	3	**–**	–	–	**68**	–	3
Segment Income (Loss)	**1,330**	1,895	1,751	**1,119**	853	(27)	**2,449**	2,748	1,724

The Oil Sands and Conventional segments operate in Canada. Both of Cenovus's refining facilities are located and carry on business in the U.S. 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 U.S. are considered to be export sales undertaken by a Canadian business. The Corporate and Eliminations segment is attributed to Canada, with the exception of the unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $671 million (2011 – $700 million; 2010 – $646 million).

D) EXPLORATION AND EVALUATION ASSETS, PROPERTY, PLANT AND EQUIPMENT, GOODWILL AND TOTAL ASSETS

By Segment

As at December 31,	Exploration and Evaluation Assets		Property, Plant and Equipment	
	2012	2011	**2012**	2011
Oil Sands	**1,110**	741	**7,764**	6,224
Conventional	**175**	139	**4,929**	4,668
Refining and Marketing	**–**	–	**3,088**	3,200
Corporate and Eliminations	**–**	–	**371**	232
Consolidated	**1,285**	880	**16,152**	14,324

As at December 31,	Goodwill		Total Assets	
	2012	2011	**2012**	2011
Oil Sands	**739**	739	**11,972**	10,524
Conventional	**–**	393	**5,304**	5,566
Refining and Marketing	**–**	–	**5,018**	4,927
Corporate and Eliminations	**–**	–	**1,922**	1,177
Consolidated	**739**	1,132	**24,216**	22,194

By Geographic Region

As at December 31,	Exploration and Evaluation Assets 2012	2011	Property, Plant and Equipment 2012	2011
Canada	**1,285**	880	**13,065**	11,124
United States	**–**	–	**3,087**	3,200
Consolidated	**1,285**	880	**16,152**	14,324

As at December 31,	Goodwill 2012	2011	Total Assets 2012	2011
Canada	**739**	1,132	**19,744**	17,536
United States	**–**	–	**4,472**	4,658
Consolidated	**739**	1,132	**24,216**	22,194

E) CAPITAL EXPENDITURES

For the years ended December 31,	**2012**	2011	2010
Capital			
Oil Sands	**2,211**	1,415	857
Conventional	**848**	788	526
Refining and Marketing	**118**	393	656
Corporate	**191**	127	76
	3,368	2,723	2,115
Acquisition Capital			
Oil Sands (2)	**69**	44	23
Conventional	**45**	25	25
Refining and Marketing	**–**	–	38
Corporate	**–**	2	–
Total (1)	**3,482**	2,794	2,201

(1) Includes expenditures on property, plant and equipment and exploration & evaluation assets.

(2) 2012 asset acquisition included the assumption of a decommissioning liability of $33 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, 2012, Cenovus had three customers (2011 – two; 2010 – two) which individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $3,928 million, $3,300 million and $2,839 million, respectively (2011 – $7,324 million and $2,683 million; 2010 – $5,376 million and $2,295 million).

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements of Cenovus were approved by the Board of Directors on February 13, 2013.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has the power to govern the financial and operating policies. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Investments in jointly controlled partnerships and unincorporated joint operations 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 consolidated accounts.

B) SEGMENT REPORTING

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow.

C) FOREIGN CURRENCY TRANSLATION

Functional and Presentation Currency

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation which continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. 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 Statements of Earnings and Comprehensive Income.

D) REVENUE AND INTEREST INCOME RECOGNITION

Sales of Product

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

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.

Interest Income

Interest income is recognized as the interest accrues using the effective interest method.

E) TRANSPORTATION AND BLENDING

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 sold.

F) 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 sold.

G) EXPLORATION EXPENSE

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the field/project/area is not technically feasible or commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

H) EMPLOYEE BENEFIT PLANS

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component, and other post-employment benefit plans ("OPEB").

Accruals for obligations under the employee defined benefit pension plan and the related costs are recorded net of plan assets.

The cost of the defined benefit pension plan and other post-employment benefits is actuarially determined using the projected unit credit 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.

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 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 non-vested expected average remaining service lives of employees and recognized immediately for vested benefits covered by the plans.

Pension expense for the defined contribution pension is recorded as the benefits are earned.

I) INCOME TAXES

Income taxes comprise current and deferred taxes. Current and deferred income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred 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, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized.

Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction.

Deferred income tax assets and liabilities are presented as non-current.

J) NET EARNINGS PER SHARE AMOUNTS

Basic net earnings per common share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

K) 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.

L) INVENTORIES

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused it no longer exist.

M) ASSETS (DISPOSAL GROUP) HELD FOR SALE

Non-current assets or disposal groups are classified as held for sale when their carrying amount will be principally recovered through a sales transaction rather than through continued use and a sales transaction is highly probable. Assets held for sale are recorded at the lower of carrying value and fair value less cost to sell.

N) EXPLORATION AND EVALUATION ("E&E") ASSETS

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired.

Once technical feasibility and commercial viability have been established for a field/project/area, the carrying value of the E&E assets associated with that field/area/project is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as property, plant and equipment.

E&E costs are subject to regular technical, commercial and management review to confirm the continued intent to develop the resources. If a field/project/area is determined to no longer be technically feasible or commercially viable, and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense in the period in which the determination occurs.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

O) PROPERTY, PLANT AND EQUIPMENT

Development and Production Assets

Development and production assets are stated at cost less accumulated depreciation, depletion, amortization and net impairment losses. Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of the crude oil and natural gas properties, as well as any E&E expenditures incurred in finding commercial reserves of crude oil or natural gas transferred from E&E assets. Capitalized costs include internal costs, decommissioning liabilities, and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For the purpose of this calculation, natural gas is converted to oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

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. Land is not depreciated.

Any gains or losses from the divestiture of development and production assets are recognized in net earnings.

Other Upstream Assets

Other upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.

Refining Assets

The refining assets are stated at cost less accumulated depreciation and net impairment losses.

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, the associated decommissioning costs and, for qualifying assets, borrowing costs. Routine maintenance and repair costs are expensed in the period in which they are incurred.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

Land Improvements and Buildings	25 to 40 years
Office Equipment and Vehicles	3 to 20 years
Refining Equipment	5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted if appropriate.

Other Assets

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. The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted, if appropriate. Assets under construction are not subject to depreciation until they are available for use. 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. Land is not depreciated.

P) IMPAIRMENT

Non-Financial Assets

Property, plant and equipment and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The recoverable amount is determined as the greater of an asset's or cash-generating unit's ("CGU") value-in-use ("VIU") and fair value less costs to sell ("FVLCTS"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or asset.

The impairment test is performed at the CGU for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses on PP&E are recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional depreciation, depletion and amortization and are separately disclosed. An impairment of E&E assets is recognized as exploration expense in the Consolidated Statements of Earnings and Comprehensive Income.

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flow and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.

An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

Q) BORROWING COSTS

Borrowing costs are recognized as an expense in the period in which they are incurred unless there is a qualifying asset. Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized when a substantial period of time is required to make the asset ready for its intended use. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use.

R) GOVERNMENT GRANTS

Government grants are recognized at fair value when there is reasonable assurance that the grants will be received and the Company will comply with the conditions of the grant. Grants related to assets are recorded as a reduction of the asset's carrying value and are depreciated over the useful life of the asset. Grants related to income are treated as a reduction of the related expense in the Consolidated Statements of Earnings and Comprehensive Income.

S) LEASES

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within property, plant and equipment.

T) BUSINESS COMBINATIONS AND GOODWILL

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

U) PROVISIONS

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities and refining facilities. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in property, plant and equipment is depreciated over the useful life of the related asset. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.

V) SHARE CAPITAL

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

W) DIVIDENDS

Dividends are accrued when declared by the Board of Directors.

X) STOCK-BASED COMPENSATION

Cenovus has a number of cash and stock-based compensation plans which include stock options with associated tandem stock appreciation rights, stock options with associated net settlement rights, performance share units and deferred share units.

Tandem Stock Appreciation Rights

Stock options with associated tandem stock appreciation rights ("TSARs") are accounted for as liability instruments which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Net Settlement Rights

Stock options with associated net settlement rights ("NSRs") are accounted for as equity instruments which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as compensation costs over the vesting period of the options, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Performance and Deferred Share Units

Performance share units ("PSUs") and deferred share units ("DSUs") are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as compensation costs over the vesting period. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

Y) FINANCIAL INSTRUMENTS

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings and Comprehensive Income.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial assets at initial recognition. Financial instruments are initially measured at fair value except in the case of "financial liabilities measured at amortized cost" which are initially measured at fair value net of directly attributable transaction costs.

The Company's consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivable, the Partnership Contribution Receivable, risk management assets and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

Fair Value through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

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 as a (gain) loss on risk management. 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 required documentation and approvals for the use of derivative financial instruments. 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.

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenue, partner loans receivable, the Partnership Contribution Receivable and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Held to Maturity Investments

"Held-to-maturity investments" are measured at amortized cost using the effective interest method of amortization.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value, with changes in the fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

Z) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2012.

AA) RECENT ACCOUNTING PRONOUNCEMENTS

New and Amended Standards Adopted

The Company did not adopt any new standards, amendments or interpretations effective during the year ended December 31, 2012.

New Standards and Interpretations not Yet Adopted

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after January 1, 2012, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2012. The standards and interpretations applicable to the Company are as follows and will be adopted on their respective effective date:

JOINT ARRANGEMENTS, CONSOLIDATION, ASSOCIATES AND DISCLOSURES

In May 2011, the IASB issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.
- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". Under IFRS 11, a joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.
- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10, but retains the current guidance for separate financial statements.
- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. It is anticipated that the application of these five standards will not have a significant impact on the Consolidated Financial Statements.

Cenovus performed a comprehensive review of its interests in other entities and identified two individually significant interests, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of the Company's accounting policy under IFRS 11 requires judgment in determining the classification of its joint arrangements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements will be classified as joint operations under IFRS 11 and the Company's share of the assets, liabilities, revenues and expenses will be recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, the Company considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

EMPLOYEE BENEFITS

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendments require the recognition of changes in defined benefit obligations and fair value of plan assets when they occur, eliminating the "corridor approach", and accelerates the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are to be recognized immediately through OCI. In addition, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendments also enhance financial statement disclosures.

The amendments to IAS 19 require retrospective application. Based on Cenovus's preliminary assessment, when the amendments are applied for the first time for the year ending December 31, 2013, net earnings for the year ended December 31, 2012 would increase by $1 million and other comprehensive income after tax would decrease by $3 million (2011 – $nil and decrease $12 million, respectively). Shareholders' equity as at December 31, 2012 would decrease by $24 million (January 1, 2012 – decrease $22 million) with corresponding adjustments, being recognized in other liabilities and deferred income taxes.

FAIR VALUE MEASUREMENT

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. IFRS 13 will not have a significant impact on the Consolidated Financial Statements.

FINANCIAL INSTRUMENTS

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses accounting for financial assets and financial liabilities. The second phase will address impairment of financial instruments and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. Although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. The Company is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

PRESENTATION OF ITEMS OF OTHER COMPREHENSIVE INCOME

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within OCI based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The adoption of this amendment will not have a significant impact on the Consolidated Financial Statements.

OFFSETTING FINANCIAL ASSETS AND FINANCIAL LIABILITIES

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures*" ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the Consolidated Balance Sheets or that are subject to enforceable master netting or similar arrangements.
- IAS 32, "*Financial Instruments: Presentation*" ("IAS 32"), has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. It is anticipated that IFRS 7 and IAS 32 will not have significant impacts on the Consolidated Financial Statements.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS 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. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) CRITICAL JUDGMENTS IN APPLYING ACCOUNTING POLICIES

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's Consolidated Financial Statements.

Exploration and Evaluation Assets

The application of the Company's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is no longer technically feasible or commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

The Company's upstream and refining assets are grouped into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining and corporate assets are assessed at the CGU level and therefore could have a significant impact on impairment losses.

B) KEY SOURCES OF ESTIMATION UNCERTAINTY

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Reserves

There are a number of inherent uncertainties associated with estimating reserves. Reserve estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would have a significant impact on the impairment test and depreciation, depletion and amortization expense of the Company's crude oil and natural gas assets. The Company's crude oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserves evaluators.

Impairment of Assets

Property, plant and equipment, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, transportation capacity and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

At December 31, 2012, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs to sell. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

OIL AND NATURAL GAS PRICES

The future prices used to determine cash flows from crude oil and natural gas reserves are as follows:

	2013	2014	2015	2016	2017	Average Annual % Change to 2024
WTI (US$/barrel)	92.50	92.50	93.60	95.50	97.40	2%
AECO ($/Mcf)	3.35	3.85	4.35	4.70	5.10	3%

DISCOUNT RATE

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent which is an industry standard rate used by independent qualified reserve evaluators in preparing their reserve reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As a result, there are usually a number of tax matters under review. As such, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

5. FINANCE COSTS

For the years ended December 31,	**2012**	2011	2010
Interest Expense – Short-Term Borrowings and Long-Term Debt	**230**	213	227
Interest Expense – Partnership Contribution Payable (Note 12)	**118**	138	165
Unwinding of Discount on Decommissioning Liabilities	**86**	75	75
Other	**21**	21	31
	455	447	498

6. INTEREST INCOME

For the years ended December 31,	**2012**	2011	2010
Interest Income – Partnership Contribution Receivable (Note 12)	**(102)**	(120)	(144)
Other	**(7)**	(4)	–
	(109)	(124)	(144)

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2012**	2011	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:			
U.S. Dollar Debt Issued from Canada	**(69)**	78	(182)
U.S. Dollar Partnership Contribution Receivable Issued from Canada	**(15)**	(107)	91
Other	**14**	(13)	22
Unrealized Foreign Exchange (Gain) Loss	**(70)**	(42)	(69)
Realized Foreign Exchange (Gain) Loss	**50**	68	18
	(20)	26	(51)

8. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31,	**2012**	2011	2010
Current Tax			
Canada	**188**	150	82
United States [1]	**121**	4	–
Total Current Tax	**309**	154	82
Deferred Tax	**474**	575	141
	783	729	223

(1) Includes $68 million of withholding tax on a U.S. dividend in 2012.

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

For the years ended December 31,	**2012**	2011	2010
Earnings Before Income Tax	**1,776**	2,207	1,304
Canadian Statutory Rate	**25.2%**	26.7%	28.2%
Expected Income Tax	**448**	589	368
Effect of Taxes Resulting from:			
Foreign Tax Rate Differential	**146**	82	(22)
Non-Deductible Stock-Based Compensation	**10**	18	34
Multi-Jurisdictional Financing	**(27)**	(50)	(93)
Foreign Exchange Gains (Losses) Not Included in Net Earnings	**14**	(9)	28
Non-Taxable Capital (Gains) Losses	**(7)**	(8)	(13)
Recognition of Capital Losses	**(22)**	26	(107)
Adjustments Arising from Prior Year Tax Filings	**33**	31	26
Withholding Tax on Foreign Dividend	**68**	–	–
Goodwill Impairment	**99**	–	–
Other	**21**	50	2
Total Tax	**783**	729	223
Effective Tax Rate	**44.1%**	33.0%	17.1%

The Canadian statutory tax rate decreased to 25.2 percent in 2012 from 26.7 percent in 2011 and 28.2 percent in 2010 as a result of tax legislation enacted in 2007. The U.S. statutory tax rate has increased to 38.5 percent in 2012 from 37.5 percent in 2011 and 2010 as a result of the allocation of taxable income to U.S. states.

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

As at December 31,	**2012**	2011
Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**140**	117
Deferred Tax Liabilities to be Settled After More Than 12 Months	**2,428**	1,984
Net Deferred Income Tax Liability	**2,568**	2,101

For the purposes of the above table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these occur in the same entity and jurisdiction. The deferred income tax liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

Deferred Income Tax Liabilities	Property Plant and Equipment	Timing of Partnership Items	Net Foreign Exchange Gains	Risk Management	Other	Total
As at January 1, 2010	1,678	9	61	17	–	1,765
Charged/(Credited) to Earnings	83	116	66	38	54	357
Charged/(Credited) to Held for Sale	2	–	–	–	–	2
Charged/(Credited) to OCI	(112)	–	–	–	1	(111)
As at December 31, 2010	1,651	125	127	55	55	2,013
Charged/(Credited) to Earnings	725	38	(15)	16	75	839
Charged/(Credited) to OCI	18	–	–	–	2	20
As at December 31, 2011	2,394	163	112	71	132	2,872
Charged/(Credited) to Earnings	418	(104)	(85)	2	(32)	199
Charged/(Credited) to OCI	(17)	–	–	–	(1)	(18)
As at December 31, 2012	**2,795**	**59**	**27**	**73**	**99**	**3,053**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
As at January 1, 2010	(242)	(33)	(9)	(284)
Charged/(Credited) to Earnings	(47)	(12)	(161)	(220)
Charged/(Credited) to OCI	8	–	–	8
As at December 31, 2010	(281)	(45)	(170)	(496)
Charged/(Credited) to Earnings	(270)	29	(21)	(262)
Charged/(Credited) to OCI	(13)	–	–	(13)
As at December 31, 2011	(564)	(16)	(191)	(771)
Charged/(Credited) to Earnings	244	11	20	275
Charged/(Credited) to OCI	11	–	–	11
As at December 31, 2012	**(309)**	**(5)**	**(171)**	**(485)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at January 1, 2010	1,481
Charged/(Credited) to Earnings	137
Charged/(Credited) to Held for Sale	2
Charged/(Credited) to OCI	(103)
Net Deferred Income Tax Liabilities as at December 31, 2010	1,517
Charged/(Credited) to Earnings	577
Charged/(Credited) to OCI	7
Net Deferred Income Tax Liabilities as at December 31, 2011	2,101
Charged/(Credited) to Earnings	474
Charged/(Credited) to OCI	(7)
Net Deferred Income Tax Liabilities as at December 31, 2012	**2,568**

The allocation of deferred income tax expense is comprised of:

As at December 31,	**2012**	2011	2010
Credited/(Charged) to Net Deferred Income Tax Liabilities	**474**	577	137
Credited/(Charged) to Liabilities Related to Assets Held for Sale	**–**	(2)	4
Deferred Income Tax Expense	**474**	575	141

No tax liability has been recognized in respect of temporary differences associated with investments in subsidiaries. As no taxes are expected to be paid in respect of these differences related to Canadian subsidiaries, the amounts have not been determined. There are no taxable temporary differences associated with investments in non-Canadian subsidiaries.

The approximate amounts of tax pools available are as follows:

As at December 31,	**2012**	2011
Canada	**4,895**	4,471
United States	**1,607**	2,740
	6,502	7,211

At December 31, 2012, the above tax pools included $13 million (2011 – $78 million; 2010 – $236 million) of Canadian non-capital losses and $791 million (2011 – $1,479 million; 2010 – $607 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2012 tax pools are Canadian net capital losses totaling $512 million (2011 – $759 million; 2010 – $983 million) which are available for carry forward to reduce future capital gains. Of these losses, $406 million are unrecognized as a deferred income tax asset at December 31, 2012 (2011 – $286 million; 2010 – $415 million). Recognition is dependent on the level of future capital gains.

9. PER SHARE AMOUNTS

A) NET EARNINGS PER SHARE

For the years ended December 31, ($ millions, except earnings per share)	**2012**	2011	2010
Net Earnings – Basic and Diluted	**993**	1,478	1,081
Weighted Average Number of Shares – Basic	**755.6**	754.0	751.9
Dilutive Effect of Cenovus TSARs	**2.9**	3.7	2.1
Dilutive Effect of NSRs	**–**	–	–
Weighted Average Number of Shares – Diluted	**758.5**	757.7	754.0
Basic Earnings per share	**$ 1.31**	$ 1.96	$ 1.44
Diluted Earnings per share	**$ 1.31**	$ 1.95	$ 1.43

B) DIVIDENDS PER SHARE

The dividends paid in 2012 were $665 million or $0.88 per share, (2011 – $603 million, $0.80 per share; 2010 – $601 million, $0.80 per share). The Cenovus Board of Directors declared a first quarter 2013 dividend of $0.242 per share, payable on March 28, 2013, to common shareholders of record as of March 15, 2013.

10. CASH AND CASH EQUIVALENTS

As at December 31,	**2012**	2011
Cash	**339**	232
Short-Term Investments	**821**	263
	1,160	495

11. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2012**	2011
Accruals	**965**	801
Trade	**232**	251
Joint Operations with Partners	**30**	30
Prepaids and Deposits	**45**	34
Interest	**23**	28
Other	**169**	261
	1,464	1,405

12. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

Cenovus has two significant joint operations, FCCL and WRB (Note 29). Through its interests in these joint operations, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Receivable and Payable which arose when Cenovus became a 50 percent partner of an integrated North American oil business. The integrated business consists of an upstream entity, FCCL, and a refining entity, WRB. On formation of the upstream entity Cenovus contributed assets, primarily Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable of an equal amount was contributed by the partner ("Partnership Contribution Receivable"). For the refining entity, the partner contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Cenovus contributed a note payable of an equal amount ("Partnership Contribution Payable").

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 receipts to date.

Mandatory Receipts – Partnership Contribution Receivable

	2013	2014	2015	2016	2017	Thereafter	**Total**
US$	386	407	429	452	117	–	**1,791**
C$ equivalent	384	405	427	450	116	–	**1,782**

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 – Partnership Contribution Payable

	2013	2014	2015	2016	2017	Thereafter	**Total**
US$	388	412	437	464	121	–	**1,822**
C$ equivalent	386	410	435	462	119	–	**1,812**

13. INVENTORIES

As at December 31,	**2012**	2011
Product		
Refining and Marketing	**1,056**	1,079
Oil Sands	**202**	186
Conventional	**1**	1
Parts and Supplies	**29**	25
	1,288	1,291

During the year ended December 31, 2012, approximately $12,378 million of produced and purchased inventory was recognized as an expense (2011 – $11,576 million; 2010 – $9,692 million). Inventory costs include purchased product, the cost of condensate blended with heavy oil and related operating costs.

14. ASSETS AND LIABILITIES HELD FOR SALE

As at December 31,	**2012**	2011
Assets Held for Sale		
Property, Plant and Equipment	**–**	116
Liabilities Related to Assets Held for Sale		
Decommissioning Liabilities	**–**	54
Deferred Income Taxes	**–**	–
	–	54

Non-Core Natural Gas Assets

At December 31, 2011, the Company classified certain non-core natural gas assets located in Northern Alberta as assets held for sale. The assets were recorded at the lesser of fair value less costs to sell and their carrying amount. This resulted in an impairment loss of approximately $2 million which has been recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income. These assets and the related liabilities were reported in the Conventional segment.

In January 2012, the Company completed the sale of these natural gas assets to an unrelated third party for net proceeds of $64 million.

15. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at December 31, 2010	713
Additions	527
Transfers to Property, Plant and Equipment (Note 16)	(356)
Divestitures	(3)
Change in Decommissioning Liabilities	(1)
As at December 31, 2011	880
Additions (1)	687
Transfers to Property, Plant and Equipment (Note 16)	(218)
Exploration Expense	(68)
Divestitures	(11)
Change in Decommissioning Liabilities	15
As at December 31, 2012	**1,285**

(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

E&E assets consist of the Company's evaluation projects which are pending the determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the year ended December 31, 2012 include $37 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – $15 million).

For the year ended December 31, 2012, $218 million of E&E assets were transferred to property, plant and equipment – development and production assets, following the determination of technical feasibility and commercial viability of the projects (year ended December 31, 2011 – $356 million).

IMPAIRMENT

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2012, $68 million of previously capitalized E&E costs related primarily to the Roncott assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense. There were no impairment losses for the years ended December 31, 2011 and 2010.

16. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2010	21,720	153	2,950	450	25,273
Additions	1,704	41	391	131	2,267
Transfers from E&E Assets (Note 15)	356	–	–	–	356
Transfers and Reclassifications	(326)	–	(5)	(2)	(333)
Change in Decommissioning Liabilities	403	–	10	1	414
Exchange Rate Movements	1	–	79	–	80
Divestitures	–	–	–	(4)	(4)
As at December 31, 2011	23,858	194	3,425	576	28,053
Additions	2,442	44	118	191	2,795
Transfers from E&E Assets (Note 15)	218	–	–	–	218
Transfers and Reclassifications	–	–	(55)	–	(55)
Change in Decommissioning Liabilities	484	–	(16)	–	468
Exchange Rate Movements	1	–	(73)	–	(72)
Divestitures	–	–	–	–	–
As at December 31, 2012	**27,003**	**238**	**3,399**	**767**	**31,407**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and Depletion Expense	1,108	15	85	40	1,248
Transfers and Reclassifications	(211)	–	(5)	–	(216)
Impairment Losses	2	–	45	–	47
Exchange Rate Movements	1	–	3	–	4
As at December 31, 2011	13,021	139	225	344	13,729
Depreciation and Depletion Expense	1,368	19	146	52	1,585
Transfers and Reclassifications	–	–	(55)	–	(55)
Impairment Losses	–	–	–	–	–
Exchange Rate Movements	1	–	(5)	–	(4)
As at December 31, 2012	**14,390**	**158**	**311**	**396**	**15,255**
CARRYING VALUE					
As at December 31, 2010	9,599	29	2,853	146	12,627
As at December 31, 2011	10,837	55	3,200	232	14,324
As at December 31, 2012	**12,613**	**80**	**3,088**	**371**	**16,152**

(1) Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.

Additions to development and production assets include internal costs directly related to the development, construction and production of crude oil and natural gas properties of $161 million (2011 – $125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized in 2012 (2011 – $nil).

Property, plant and equipment include the following amounts in respect of assets not available for use which are not subject to depreciation until put into use:

As at December 31,	**2012**	2011
Development and Production	**38**	52
Refining Equipment	**13**	125
Other	**11**	112
	62	289

IMPAIRMENT

The impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income.

Depreciation, depletion and amortization expense includes impairment losses as follows:

For the years ended December 31,	**2012**	2011	2010
Development and Production	**–**	2	–
Refining Equipment	**–**	45	14
	–	47	14

There were no impairments or impairment reversals of property, plant and equipment in 2012. The impairment losses for the year ended December 31, 2011 were related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations, and an impairment on non-core natural gas assets that were reclassified as held for sale (Note 14). The natural gas assets reside in the Conventional segment. The 2010 impairment loss related to a processing unit at the Borger Refinery which was determined to be a redundant asset.

17. DIVESTITURES

In January 2012, the Company completed the sale of non-core natural gas assets located in Northern Alberta. A loss of $2 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

In 2011, the Company disposed of non-core crude oil and natural gas properties and marine terminal facilities recognizing an after-tax gain of $91 million in the Statement of Earnings and Comprehensive Income. In 2010, an after-tax gain of $116 million was recognized on the disposition of non-core crude oil and natural gas properties and corporate assets.

18. OTHER ASSETS

As at December 31,	**2012**	2011
Long-Term Receivables	**22**	18
Prepaids	**8**	8
Other	**28**	18
	58	44

19. GOODWILL

As at December 31,	**2012**	2011
Carrying Value, Beginning of Year	**1,132**	1,132
Impairment	**(393)**	–
Carrying Value, End of Year	**739**	1,132

There were no additions to goodwill during 2012 or 2011.

IMPAIRMENT TEST FOR CASH-GENERATING UNITS CONTAINING GOODWILL

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose on the acquisition of exploration and production assets. The carrying amount of goodwill allocated to the Company's exploration and production CGUs was as follows:

As at December 31,	**2012**	2011
Suffield	**–**	393
Foster Creek	**242**	242
Northern Alberta	**497**	497
	739	1,132

At December 31, 2012, the Company determined that the carrying amount of the Suffield CGU exceeded its fair value less costs to sell and the full amount of the impairment was attributed to goodwill. This goodwill arose in 2002 upon the formation of the predecessor corporation. An impairment loss of $393 million was recorded as goodwill impairment on the Consolidated Statement of Earnings and Comprehensive Income. The Suffield property resides on the Canadian Forces Base in southeast Alberta and the operating results are included in the Conventional segment. Future cash flows for the area have declined due to lower natural gas and crude oil prices and increased operating costs. In addition, minimal levels of capital spending for natural gas resulted in production exceeding reserve replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the goodwill exceeded its fair value.

The recoverable amount was determined using fair value less costs to sell. A calculation based on discounted after-tax cash flows of proved and probable reserves using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators was completed (Note 4). To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed.

There was no impairment of goodwill in 2011 or 2010.

SENSITIVITIES

Changes to the assumed discount rate or forward price estimates independently would have the following impact on the impairment of the Suffield CGU:

	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Price Estimates
Impairment of Goodwill	**–**	**–**
Impairment of PP&E	**50**	**100**

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2012**	2011
Accruals	**1,510**	1,193
Trade	**676**	789
Employee Long-Term Incentives	**196**	209
Interest	**82**	72
Other	**186**	316
	2,650	2,579

21. LONG-TERM DEBT

As at December 31,		**2012**	2011
Revolving Term Debt (1)	A	**–**	–
U.S. Dollar Denominated Unsecured Notes	B	**4,726**	3,559
Total Debt Principal	C	**4,726**	3,559
Debt Discounts and Transaction Costs	D	**(47)**	(32)
		4,679	3,527

(1) Revolving term debt may include 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, 2012 was 5.3 percent (2011 – 5.5 percent, 2010 – 5.8 percent).

A) REVOLVING TERM DEBT

At December 31, 2012, Cenovus had in place a committed credit facility in the amount of $3.0 billion or the equivalent amount in U.S. dollars. The committed credit facility was renegotiated in September 2012 to slightly reduce both the standby fees required to maintain the facility as well as the cost of future borrowings. The maturity date was extended to November 30, 2016 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, 2012, there were no amounts drawn on Cenovus's committed bank credit facility (2011 – $nil).

B) UNSECURED NOTES

Unsecured notes are comprised of the following:

As at December 31,	**US$ Principal Amount**	**2012**	2011
4.50% due September 15, 2014	**800**	**796**	814
5.70% due October 15, 2019	**1,300**	**1,293**	1,322
3.00% due August 15, 2022	**500**	**498**	–
6.75% due November 15, 2039	**1,400**	**1,393**	1,423
4.45% due September 15, 2042	**750**	**746**	–
	4,750	**4,726**	3,559

Cenovus has in place a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. 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, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 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, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, US$750 million remains under this U.S. base shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 17, 2012, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$500 million, with a coupon rate of 3.00 percent, due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042, for an aggregate principal amount of US$1.25 billion. The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

As at December 31, 2012, the Company is in compliance with all of the terms of its debt agreements.

C) MANDATORY DEBT PAYMENTS

	US$ Principal Amount	C$ Principal Amount	**Total C$ Equivalent**
2013	–	–	**–**
2014	800	–	**796**
2015	–	–	**–**
2016	–	–	**–**
2017	–	–	**–**
Thereafter	3,950	–	**3,930**
	4,750	–	**4,726**

D) DEBT DISCOUNTS AND TRANSACTION COSTS

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are being amortized over the remaining term of the committed credit facility. During 2012, additional transaction costs of $19 million were recorded (2011 – $3 million).

22. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets and refining facilities. The aggregate carrying amount of the obligation is as follows:

As at December 31,	**2012**	2011
Decommissioning Liabilities, Beginning of Year	**1,777**	1,399
Liabilities Incurred	**99**	49
Liabilities Settled	**(66)**	(56)
Transfers and Reclassifications	**3**	(55)
Change in Estimated Future Cash Flows	**144**	146
Change in Discount Rate	**273**	218
Unwinding of Discount on Decommissioning Liabilities	**86**	75
Foreign Currency Translation	**(1)**	1
Decommissioning Liabilities, End of Year	**2,315**	1,777

The undiscounted amount of estimated cash flows required to settle the obligation is $6,865 million (2011 – $6,541 million), which has been discounted using a credit-adjusted risk-free rate of 4.2 percent (2011 – 4.8 percent). Most of these obligations are not expected to be paid for several years, or decades, and will be funded from general resources at that time. Revisions in estimated cash flows resulted from accelerated timing of forecast abandonment and reclamation spending and higher cost estimates.

SENSITIVITIES

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2012		2011	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(408)**	**572**	(367)	504
One Percent Decrease	**565**	**(418)**	494	(379)

23. OTHER LIABILITIES

As at December 31,	**2012**	2011
Deferred Revenue	**31**	35
Employee Long-Term Incentives	**64**	55
Pension and Other Post-Employment Benefits (Note 24)	**28**	16
Other	**28**	22
	151	128

24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and other post-employment benefit plans ("OPEB"). Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria are eligible to elect to convert from the current defined contribution pension to a defined benefit pension.

The Company is required to file an actuarial valuation of its registered defined benefit pension plan with the provincial regulator at least every three years. The most recently filed valuation was dated June 30, 2012 and the next required actuarial valuation will be as at December 31, 2014.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The defined benefit pension is funded according to the federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plans are based on the results of the actuarial valuation and direction by the Human Resources and Compensation Committee of the Board.

The Company's OPEB provides retired employees with life insurance benefits, health care and dental benefits until age 65. These benefits are funded on an as required basis.

A) DEFINED BENEFIT AND OPEB PLAN OBLIGATION AND FUNDED STATUS

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

	Pension Benefits		OPEB	
As at December 31,	**2012**	2011	**2012**	2011
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**84**	68	**19**	14
Current Service Costs	**10**	3	**2**	2
Interest Costs	**4**	3	**1**	1
Benefits Paid	**(2)**	(1)	**–**	–
Plan Participant Contributions	**1**	–	**–**	–
Actuarial (Gains) Losses	**7**	11	**(2)**	2
Plan Conversion	**30**	–	**–**	–
Defined Benefit Obligation, End of Year	**134**	84	**20**	19
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**61**	59	**–**	–
Expected Return on Plan Assets	**4**	3	**–**	–
Employer Contributions	**22**	4	**–**	–
Plan Participant Contributions	**1**	–	**–**	–
Actuarial Gains (Losses)	**–**	(4)	**–**	–
Benefits Paid	**(2)**	(1)	**–**	–
Asset Transfer from Plan Conversion	**12**	–	**–**	–
Fair Value of Plan Assets, End of Year	**98**	61	**–**	–
Funded Status – Plan Assets (Less) than Benefit Obligation	**(36)**	(23)	**(20)**	(19)
Unamortized Net Actuarial (Gain) Loss not Recognized	**26**	22	**2**	4
Pension and Other Post-Employment Benefit (Liability)	**(10)**	(1)	**(18)**	(15)

The pension and other post-employment benefit liability is included in other liabilities on the Consolidated Balance Sheets.

B) PENSION AND OTHER POST-EMPLOYMENT BENEFIT COSTS

Pension and other post-employment benefit costs are as follows:

	Pension Benefits			OPEB		
For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Current Service Cost	**10**	3	3	**3**	2	1
Interest Cost	**4**	4	3	**1**	1	1
Expected Return on Plan Assets	**(4)**	(4)	(3)	**–**	–	–
Actuarial Gains (Losses)	**3**	1	–	**–**	–	–
Past Service Cost (1)	**18**	–	–	**–**	–	–
Defined Benefit Plan Cost	**31**	4	3	**4**	3	2
Defined Contribution Plan Cost	**25**	22	18	**–**	–	–
Total Plan Cost	**56**	26	21	**4**	3	2

(1) Past service costs for eligible employees who were given a one-time option to convert from the defined contribution pension to defined benefit pension retrospectively to the later of the date they would have been eligible to enroll in the defined benefit pension or November 30, 2009. Past service costs were fully vested and recorded immediately.

Pension costs are recorded in operating and general and administrative expenses, and PP&E and E&E assets, corresponding to where the associated salaries and wages of the employees rendering the service are recorded.

C) ACTUARIAL ASSUMPTIONS

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			OPEB		
	2012	2011	2010	**2012**	2011	2010
Benefit Obligation at December 31						
Discount Rate	**4.00%**	4.25%	5.25%	**4.00%**	4.25%	5.25%
Rate of Compensation Increase	**4.39%**	3.99%	4.05%	**5.77%**	5.77%	5.65%
Benefit Expense for the Year						
Discount Rate	**4.25%**	5.25%	6.00%	**4.25%**	5.25%	6.00%
Expected Return on Plan Assets	**5.54%**	5.59%	5.59%	**N/A**	N/A	N/A
Rate of Compensation Increase	**3.99%**	4.05%	4.05%	**5.77%**	5.65%	5.77%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio.

The expected average remaining service period of the active employees covered by the defined benefit pension and OPEB plans are seven and 11 years, respectively.

Assumed health care cost trend rates are as follows:

	2012	2011	2010
Health Care Cost Trend for Next Year	**8%**	10%	10%
Rate that the Trend Rate Gradually Trends to	**5%**	5%	5%
Year that the Trend Rate Reaches the Rate Which it is Expected to Remain At	**2021**	2022	2021

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

	One Percentage Point Increase	**One Percentage Point Decrease**
Effect on Service and Interest Cost	**–**	**–**
Effect on Pension and Other Post-Employment Benefit Liability	**1**	**(1)**

D) PLAN ASSETS AND INVESTMENT OBJECTIVES

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The actual return on the plan assets for the year ended December 31, 2012 was $3 million (2011 – $nil).

The Company's weighted average pension plan asset allocation, based on market values as at December 31, 2012 and 2011, are as follows:

	Target Allocation	Percentage of Plan Assets	
		2012	2011
Equity Securities	**65-70%**	**63%**	60%
Debt Securities	**30%**	**30%**	33%
Real Estate and Other	**0-5%**	**7%**	7%
Total	**100%**	**100%**	100%

Equity securities do not include any direct investments in Cenovus shares.

The expected contributions for the year ended December 31, 2013 is $15 million for the defined benefit pension plan and $nil for the OPEB.

E) DEFINED BENEFIT PLAN AND OPEB EXPERIENCE ADJUSTMENTS

Experience adjustments as a percentage of total plan assets and liabilities are as follows:

As at December 31,	**2012**	2011	2010
Defined Benefit			
Experience Adjustments Arising on Plan Liabilities	**2%**	(1%)	3%
Experience Adjustments Arising on Plan Assets	**0%**	7%	(2%)
OPEB			
Experience Adjustments Arising on Plan Liabilities	**3%**	2%	2%

25. SHARE CAPITAL

A) 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. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) ISSUED AND OUTSTANDING

	2012		2011	
As at December 31,	**Number of Common Shares** *(thousands)*	**Amount**	Number of Common Shares *(thousands)*	Amount
Outstanding, Beginning of Year	**754,499**	**3,780**	752,675	3,716
Common Shares Issued under Stock Option Plans	**1,344**	**49**	1,824	64
Outstanding, End of Year	**755,843**	**3,829**	754,499	3,780

There were no preferred shares outstanding as at December 31, 2012 (2011 – nil).

At December 31, 2012, there were 28 million (2011 – 30 million) common shares available for future issuance under stock option plans.

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.

C) PAID IN SURPLUS

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana under the Arrangement into two independent energy companies, Encana and Cenovus. In addition, paid in surplus includes compensation expense related to the Company's NSRs discussed in Note 26 A.

	Pre-Arrangement Earnings	**Stock-Based Compensation**	**Total**
As at December 31, 2010	4,083	–	4,083
Stock-Based Compensation Expense	–	24	24
As at December 31, 2011	4,083	24	4,107
Stock-Based Compensation Expense	–	47	47
As at December 31, 2012	**4,083**	**71**	**4,154**

26. STOCK-BASED COMPENSATION PLANS

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 or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 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 option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

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 1, 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.

As at December 31, 2012	**Issued**	**Term** *(Years)*	**Weighted Average Remaining Contractual Life** *(Years)*	**Weighted Average Exercise Price** *($)*	**Closing Share Price** *($)*	**Units Outstanding**
Encana Replacement TSARs held by Cenovus Employees	Prior to Arrangement	5	0.66	32.66	19.66	7,722
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	5	0.70	29.29	33.29	5,229
TSARs	Prior to February 17, 2010	5	0.72	29.28	33.29	6,225
TSARs	On or After February 17, 2010	7	4.20	26.71	33.29	5,026
NSRs	On or After February 24, 2011	7	5.85	37.52	33.29	15,074

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

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2012 was $7.62 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	1.37%
Expected Dividend Yield	2.31%
Expected Volatility (1)	28.62%
Expected Life (Years)	4.55

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize information related to the NSRs as at December 31, 2012:

As at December 31, 2012 (thousands of units)	**NSRs**	**Weighted Average Exercise Price** *($)*
Outstanding, Beginning of Year	5,809	36.95
Granted	9,665	37.87
Exercised for Common Shares	(5)	33.99
Forfeited	(395)	37.56
Outstanding, End of Year	15,074	37.52
Exercisable, End of Year	1,700	36.98

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $35.28.

As at December 31, 2012 Range of Exercise Price ($)	Outstanding NSRs (thousands of units) NSRs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
30.00 to 39.99	**15,074**	**5.85**	**37.52**

As at December 31, 2012 Range of Exercise Price ($)	Exercisable NSRs (thousands of units) NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	**1,700**	**36.98**

TSARs Held by Cenovus Employees

The Company has recorded a liability of $64 million at December 31, 2012 (December 31, 2011 – $90 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.28%**
Expected Dividend Yield	**2.58%**
Expected Volatility [1]	**27.80%**
Cenovus's Common Share Price	**$ 33.29**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2012 was $45 million (2011 – $43 million).

The following tables summarize information related to the TSARs held by Cenovus employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	9,391	5,530	**14,921**	**28.12**
Granted	–	–	**–**	**–**
Exercised for Cash Payment	(937)	(1,057)	**(1,994)**	**28.52**
Exercised as Options for Common Shares	(683)	(641)	**(1,324)**	**27.77**
Forfeited	(134)	(207)	**(341)**	**26.77**
Expired	(11)	–	**(11)**	**30.85**
Outstanding, End of Year	**7,626**	**3,625**	**11,251**	**28.13**
Exercisable, End of Year	**5,369**	**3,625**	**8,994**	**28.46**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.73.

As at December 31, 2012 Range of Exercise Price ($)	Outstanding TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	6,269	2,143	**8,412**	**2.88**	**26.38**
30.00 to 39.99	1,294	1,482	**2,776**	**0.48**	**33.10**
40.00 to 49.99	63	–	**63**	**0.45**	**43.29**
	7,626	**3,625**	**11,251**	**2.27**	**28.13**

As at December 31, 2012 *Range of Exercise Price ($)*	Exercisable TSARs *(thousands of units)* TSARs	 Performance TSARs	 Total	 Weighted Average Exercise Price *($)*
20.00 to 29.99	4,132	2,143	**6,275**	**26.35**
30.00 to 39.99	1,174	1,482	**2,656**	**33.11**
40.00 to 49.99	63	–	**63**	**43.29**
	5,369	**3,625**	**8,994**	**28.46**

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.

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 $1 million at December 31, 2012 (2011 – $1 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.21%**
Expected Dividend Yield	**3.86%**
Expected Volatility [1]	**30.40%**
Encana's Common Share Price	**$ 19.66**

(1) Expected volatility has been based on the historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at December 31, 2012 was $nil (2011 – $nil).

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price *($)*
Outstanding, Beginning of Year	4,281	6,130	**10,411**	**31.97**
Exercised for Cash Payment	–	–	**–**	**–**
Exercised as Options for Encana Common Shares	–	–	**–**	**–**
Forfeited	(112)	(333)	**(445)**	**31.04**
Expired	(1,008)	(1,236)	**(2,244)**	**29.79**
Outstanding, End of Year	**3,161**	**4,561**	**7,722**	**32.66**
Exercisable, End of Year	**3,161**	**4,561**	**7,722**	**32.66**

As at December 31, 2012 *Range of Exercise Price ($)*	Outstanding & Exercisable TSARs *(thousands of units)* TSARs	 Performance TSARs	 Total	 Weighted Average Remaining Contractual Life *(Years)*	 Weighted Average Exercise Price *($)*
20.00 to 29.99	1,564	2,510	**4,074**	**1.12**	**29.02**
30.00 to 39.99	1,465	2,051	**3,516**	**0.15**	**36.41**
40.00 to 49.99	130	–	**130**	**0.48**	**44.85**
50.00 to 59.99	2	–	**2**	**0.39**	**50.39**
	3,161	**4,561**	**7,722**	**0.66**	**32.66**

The closing price of Encana common shares on the TSX as at December 31, 2012 was $19.66.

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana 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.

The Company has recorded a liability of $35 million at December 31, 2012 (2011 – $83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.21%**
Expected Dividend Yield	**2.58%**
Expected Volatility [1]	**27.80%**
Cenovus's Common Share Price	**$ 33.29**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at December 31, 2012 was $22 million (2011 – $32 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Exercise Price** *($)*
Outstanding, Beginning of Year	3,935	5,751	**9,686**	**28.96**
Exercised for Cash Payment	(1,788)	(2,189)	**(3,977)**	**28.69**
Exercised as Options for Common Shares	(8)	(12)	**(20)**	**26.64**
Forfeited	(84)	(314)	**(398)**	**27.67**
Expired	(30)	(32)	**(62)**	**27.67**
Outstanding, End of Year	**2,025**	**3,204**	**5,229**	**29.29**
Exercisable, End of Year	**2,025**	**3,204**	**5,229**	**29.29**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.72.

	Outstanding & Exercisable TSARs *(thousands of units)*				
As at December 31, 2012 Range of Exercise Price ($)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Remaining Contractual Life** *(Years)*	**Weighted Average Exercise Price** *($)*
20.00 to 29.99	1,087	1,899	**2,986**	**1.12**	**26.27**
30.00 to 39.99	886	1,305	**2,191**	**0.14**	**33.08**
40.00 to 49.99	52	–	**52**	**0.44**	**42.70**
	2,025	**3,204**	**5,229**	**0.70**	**29.29**

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.

B) PERFORMANCE SHARE UNITS

Cenovus 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. For a portion of PSUs, 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. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $124 million at December 31, 2012 (2011 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2012. The intrinsic value of vested PSUs was $nil at December 31, 2012 and 2011 as PSUs are paid out upon vesting.

The following table summarizes the information related to the PSUs held by Cenovus employees as at December 31, 2012:

(thousands of units)	PSUs
Outstanding, Beginning of Year	**2,623**
Granted	**2,704**
Cancelled	**(183)**
Units in Lieu of Dividends	**114**
Outstanding, End of Year	**5,258**

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 zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $36 million at December 31, 2012 (2011 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2012. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2012:

(thousands of units)	DSUs
Outstanding, Beginning of Year	**1,042**
Granted to Directors	**64**
Granted from Annual Bonus Awards	**22**
Units in Lieu of Dividends	**30**
Exercised	**(74)**
Outstanding, End of Year	**1,084**

D) TOTAL 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:

For the years ended December 31,	**2012**	2011	2010
NSRs	**27**	16	–
TSARs Held by Cenovus Employees	**(1)**	24	45
Encana Replacement TSARs Held by Cenovus Employees	**–**	(8)	(20)
PSUs	**46**	27	13
DSUs	**3**	4	9
Total Stock-Based Compensation Expense (Recovery)	**75**	63	47

27. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2012**	2011	2010
Salaries, Bonuses and Other Short-Term Employee Benefits	**441**	399	348
Defined Contribution Pension Plan	**14**	13	11
Defined Benefit Pension Plan and OPEB	**20**	4	(1)
Stock-Based Compensation (Note 26)	**75**	63	47
	550	479	405

28. RELATED PARTY TRANSACTIONS

KEY MANAGEMENT COMPENSATION

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is as follows:

For the years ended December 31,	**2012**	2011	2010
Salaries, Director Fees and Short-Term Benefits	**27**	25	22
Post-Employment Benefits	**7**	3	2
Other Long-Term Benefits	**–**	–	–
Stock-Based Compensation	**35**	35	37
Total	**69**	63	61

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recognized during the year associated with stock options, NSRs, TSARs, PSUs and DSUs.

29. INTEREST IN JOINT OPERATIONS

On January 2, 2007, Cenovus became a 50 percent partner in an integrated North American heavy oil business. The integrated business is structured through two joint arrangements. The upstream entity, FCCL Partnership, is involved in the development and production of crude oil and is jointly controlled with ConocoPhillips. The refining entity, WRB Refining LP, includes two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with Phillips 66.

Cenovus recognizes its share of the assets, liabilities, revenues and expenses (proportionately consolidates) of these joint operations with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Cenovus's Consolidated Financial Statements include the following amounts related to these joint arrangements:

	FCCL Partnership (1)			WRB Refining LP (1)		
Statements of Earnings For the years ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Revenues	**3,132**	2,364	1,829	**9,160**	8,672	6,624
Expenses						
Purchased Product	**–**	–	–	**7,339**	7,223	6,095
Operating, Transportation and Blending and Realized Gain/Loss on Risk Management	**1,944**	1,397	1,074	**552**	473	462
Operating Cash Flow	**1,188**	967	755	**1,269**	976	67
Depreciation, Depletion and Amortization	**303**	205	210	**135**	130	86
Other Expenses (Income)	**1**	(136)	20	**4**	(4)	13
Net Earnings (Loss)	**884**	898	525	**1,130**	850	(32)

(1) FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.

	FCCL Partnership		WRB Refining LP	
As at December 31,	**2012**	2011	**2012**	2011
Cash and Cash Equivalents	**388**	145	**172**	166
Other Current Assets	**761**	792	**1,111**	1,236
Long-Term Assets	**7,599**	6,864	**3,087**	3,188
Current Liabilities	**350**	317	**566**	759
Long-Term Liabilities	**137**	83	**58**	73

Capital commitments through jointly controlled entities are as follows:

As at December 31, 2012	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Capital Commitments [1]	268	34	44	40	2	1	**389**

(1) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.

As at December 31, 2011	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Capital Commitments [1]	179	58	11	2	3	–	253

(1) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.

There are no contingent liabilities related to the Company's interest in jointly controlled entities, nor contingent liabilities of the jointly controlled entities themselves.

30. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. 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 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 ("Adjusted EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at December 31,	**2012**	2011
Long-Term Debt	**4,679**	3,527
Shareholders' Equity	**9,806**	9,406
Capitalization	**14,485**	12,933
Debt to Capitalization	**32%**	27%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

As at December 31,	**2012**	2011	2010
Debt	**4,679**	3,527	3,432
Net Earnings	**993**	1,478	1,081
Add (Deduct):			
Finance Costs	**455**	447	498
Interest Income	**(109)**	(124)	(144)
Income Tax Expense	**783**	729	223
Depreciation, Depletion and Amortization	**1,585**	1,295	1,302
Goodwill Impairment	**393**	–	–
Exploration Expense	**68**	–	–
Unrealized (Gain) Loss on Risk Management	**(57)**	(180)	(46)
Foreign Exchange (Gain) Loss, net	**(20)**	26	(51)
(Gain) Loss on Divestiture of Assets	**–**	(107)	(116)
Other (Income) Loss, net	**(5)**	4	(13)
Adjusted EBITDA	**4,086**	3,568	2,734
Debt to Adjusted EBITDA	**1.1x**	1.0x	1.3x

It is Cenovus's intention to maintain investment grade credit ratings to help 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 its 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.

At December 31, 2012, Cenovus is in compliance with all of the terms of its debt agreements.

31. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings 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, partner loans and long-term receivables 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 prices sourced from market data. As at December 31, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $4,679 million and the fair value was $5,582 million (December 31, 2011 carrying value – $3,527 million, fair value – $4,316 million).

B) RISK MANAGEMENT ASSETS AND LIABILITIES

Under the terms of the Arrangement, 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,	**2012**	2011
Risk Management Assets		
Current Asset	**283**	232
Long-Term Asset	**5**	52
	288	284
Risk Management Liabilities		
Current Liability	**17**	54
Long-Term Liability	**1**	14
	18	68
Net Risk Management Asset (Liability)	**270**	216

Summary of Unrealized Risk Management Positions

	2012			2011		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**221**	**16**	**205**	22	65	(43)
Natural Gas	**66**	**1**	**65**	247	3	244
Power	**1**	**1**	**–**	15	–	15
Total Fair Value	**288**	**18**	**270**	284	68	216

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at December 31,	**2012**	2011
Prices Actively Quoted (Level 1)	**120**	226
Prices Sourced from Observable Data or Market Corroboration (Level 2)	**150**	(10)
Total Fair Value	**270**	216

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, 2012

As at December 31, 2012	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price (1)	18,500 bbls/d	2013	US$110.36/bbl	**23**
Brent Fixed Price (1)	18,500 bbls/d	2013	$111.72/bbl	**33**
WCS Differential (2)	49,200 bbls/d	2013	US$(20.74)/bbl	**145**
WCS Differential (2)	9,400 bbls/d	2014	US$(20.13)/bbl	**5**
Other Financial Positions (3)				**(1)**
Crude Oil Fair Value Position				**205**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	**66**
Other Fixed Price Contracts (4)				**(1)**
Natural Gas Fair Value Position				**65**
Power Purchase Contracts				
Power Fair Value Position				**–**

(1) Brent fixed price positions consist of both Brent fixed price swaps and WTI swaps converted to Brent.

(2) Cenovus has entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.

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

(4) Cenovus has entered into other fixed price contracts to protect against widening price differentials between production areas and various sales points.

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

For the years ended December 31,	**2012**	2011	2010
Realized Gain (Loss) (1)			
Crude Oil	**81**	(135)	(17)
Natural Gas	**247**	210	289
Refining	**7**	(14)	10
Power	**1**	7	(4)
	336	68	278
Unrealized Gain (Loss) (2)			
Crude Oil	**247**	106	(92)
Natural Gas	**(176)**	38	152
Refining	**1**	7	(8)
Power	**(15)**	29	(6)
	57	180	46
Gain (Loss) on Risk Management	**393**	248	324

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.

(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

Reconciliation of Unrealized Risk Management Positions from January 1 to December 31, 2012

	2012		2011	2010
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**216**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**393**	**393**	248	324
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(3)**	**–**	–	–
Fair Value of Contracts Realized During the Year	**(336)**	**(336)**	(68)	(278)
Fair Value of Contracts, End of Year	**270**	**57**	180	46

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. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices on the Company's open risk management positions as at December 31 could have resulted in unrealized gains (losses) impacting earnings before income tax for the year ended December 31 as follows:

RISK MANAGEMENT POSITIONS IN PLACE AS AT DECEMBER 31, 2012

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent & WTI Hedges	**(156)**	**156**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	**111**	**(111)**
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX Natural Gas Hedges	**(55)**	**55**
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	**1**	**(1)**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**

RISK MANAGEMENT POSITIONS IN PLACE AS AT DECEMBER 31, 2011

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to WTI Hedges	(214)	214
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	67	(67)
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX and AECO Hedges	(160)	160
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	2	(2)
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)

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 instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX price. 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 a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of 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 and with large commercial counterparties, most of which have 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. At December 31, 2012 and 2011, substantially all of the Company's accounts receivable were current. As at December 31, 2012, 87 percent (2011 – 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2012, Cenovus had two counterparties (2011 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value. The majority 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 and by maintaining appropriate access to credit. As disclosed in Note 30, over the long term, 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, 2012, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$750 million under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

2012	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,650	–	–	–	**2,650**
Risk Management Liabilities	17	1	–	–	**18**
Long-Term Debt [(1)]	254	1,263	432	7,051	**9,000**
Partnership Contribution Payable [(1)]	486	972	609	–	**2,067**
Other [(1)]	–	9	4	4	**17**

(1) Principal and interest, including current portion.

2011	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,579	–	–	–	2,579
Risk Management Liabilities	54	14	–	–	68
Long-Term Debt [(1)]	208	1,230	343	5,182	6,963
Partnership Contribution Payable [(1)]	497	994	994	125	2,610
Other [(1)]	3	10	3	4	20

(1) Principal and interest, including current portion.

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.

As disclosed in Note 7, 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, 2012, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2011 – US$3,500 million; 2010 – US$3,500 million) and US$1,791 million related to the U.S. dollar Partnership Contribution Receivable (2011 – US$2,157 million; 2010 – US$2,505 million). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $30 million change in foreign exchange (gain) loss at December 31, 2012 (2011 – $13 million; 2010 – $10 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect 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, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2011 – $nil; 2010 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

32. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2012**	2011	2010
Interest Paid	**342**	357	423
Interest Received	**113**	128	148
Income Taxes Paid	**304**	–	62

33. 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:

2012	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Pipeline Transportation (1)	145	209	378	403	675	8,130	**9,940**
Operating Leases (Building Leases)	109	106	112	110	104	1,602	**2,143**
Product Purchases	81	18	18	6	–	–	**123**
Capital Commitments (2)	320	54	61	53	6	2	**496**
Other Long-Term Commitments	33	25	18	7	6	10	**99**
Total Payments (3)	688	412	587	579	791	9,744	**12,801**
Fixed Price Product Sales	50	52	54	55	3	–	**214**

(1) Certain transportation commitments included are subject to regulatory approval.

(2) Includes those commitments related to jointly controlled entities.

(3) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.

2011	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Pipeline Transportation (1)	143	137	187	311	347	2,754	3,879
Operating Leases (Building Leases)	71	93	85	80	80	1,491	1,900
Product Purchases	19	18	19	19	6	–	81
Capital Commitments (2)	366	98	40	23	22	20	569
Other Long-Term Commitments	5	4	1	1	–	1	12
Total Payments (3)	604	350	332	434	455	4,266	6,441
Fixed Price Product Sales	52	54	56	57	60	3	282

(1) Certain transportation commitments included are subject to regulatory approval.

(2) Includes those commitments related to jointly controlled entities.

(3) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.

At December 31, 2012, there were outstanding letters of credit aggregating $36 million issued as security for performance under certain contracts (2011 – $17 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 31.

B) CONTINGENCIES

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recognized a liability of $2,315 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. 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.

34. SUBSEQUENT EVENT

Subsequent to December 31, 2012, Management decided to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The public sales process is expected to be launched in late February 2013. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. Operating results from these properties are included in the Conventional segment.

SUPPLEMENTAL INFORMATION

(UNAUDITED)

FINANCIAL STATISTICS

	2012					2011				
($ millions, except per share amounts)	**Year**	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**17,229**	3,802	4,462	4,279	4,686	16,185	4,480	3,989	4,085	3,631
Less: Royalties	**387**	78	122	65	122	489	151	131	76	131
Revenues	**16,842**	3,724	4,340	4,214	4,564	15,696	4,329	3,858	4,009	3,500
OPERATING CASH FLOW										
Crude Oil and Natural Gas Liquids										
Foster Creek	**924**	246	227	223	228	780	213	194	222	151
Christina Lake	**343**	118	93	70	62	125	61	19	23	22
Pelican Lake	**418**	98	108	85	127	305	69	83	76	77
Conventional	**962**	240	227	228	267	881	246	209	218	208
Natural Gas	**513**	134	126	121	132	777	188	200	197	192
Other Upstream Operations	**9**	5	2	–	2	13	4	2	3	4
	3,169	841	783	727	818	2,881	781	707	739	654
Refining and Marketing	**1,267**	122	527	351	267	981	238	238	325	180
Operating Cash Flow (1)	**4,436**	963	1,310	1,078	1,085	3,862	1,019	945	1,064	834
CASH FLOW INFORMATION										
Cash from Operating Activities	**3,420**	758	1,029	968	665	3,273	952	921	769	631
Deduct (Add back):										
Net change in other assets and liabilities	**(113)**	(42)	(19)	(20)	(32)	(82)	(20)	(17)	(16)	(29)
Net change in non-cash working capital	**(110)**	103	(69)	63	(207)	79	121	145	(154)	(33)
Cash Flow (2)	**3,643**	697	1,117	925	904	3,276	851	793	939	693
Per share – Basic	**4.82**	0.92	1.48	1.22	1.20	4.34	1.13	1.05	1.25	0.92
– Diluted	**4.80**	0.92	1.47	1.22	1.19	4.32	1.12	1.05	1.24	0.91
Operating Earnings (3)	**866**	(189)	432	283	340	1,239	332	303	395	209
Per share – Diluted	**1.14**	(0.25)	0.57	0.37	0.45	1.64	0.44	0.40	0.52	0.28
Net Earnings	**993**	(118)	289	396	426	1,478	266	510	655	47
Per share – Basic	**1.31**	(0.16)	0.38	0.52	0.56	1.96	0.35	0.68	0.87	0.06
– Diluted	**1.31**	(0.16)	0.38	0.52	0.56	1.95	0.35	0.67	0.86	0.06
Effective Tax Rates using										
Net Earnings	**44.1%**					33.0%				
Operating Earnings, excluding divestitures	**47.0%**					34.5%				
Canadian Statutory Rate	**25.2%**					26.7%				
U.S. Statutory Rate	**38.5%**					37.5%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**1.001**	1.009	1.005	0.990	0.999	1.012	0.978	1.020	1.033	1.015
Period end	**1.005**	1.005	1.017	0.981	1.001	0.983	0.983	0.963	1.037	1.029

(1) Operating Cash Flow is a non-GAAP measure defined as revenue less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities.

(2) 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.

(3) 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 risk management gains (losses) on derivative instruments, 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, after-tax gains (losses) on divestiture of assets, deferred 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)*

	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
FINANCIAL METRICS (NON-GAAP MEASURES)										
Debt to Capitalization [4], [5]	**32%**					27%				
Debt to Adjusted EBITDA [5], [6]	**1.1x**					1.0x				
Return on Capital Employed [7]	**9%**					13%				
Return on Common Equity [8]	**10%**					17%				

(4) Capitalization is a non-GAAP measure defined as Debt plus Shareholders' Equity.

(5) Debt includes the Company's short-term borrowings plus long-term debt, including the current portion of long-term debt.

(6) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.

(7) Calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average Shareholders' Equity plus average Debt.

(8) Calculated, on a trailing twelve-month basis, as net earnings divided by average Shareholders' Equity.

COMMON SHARE INFORMATION	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period end	**755.8**	755.8	755.8	755.7	755.6	754.5	754.5	754.3	754.1	753.9
Average – Basic	**755.6**	755.8	755.7	755.7	755.1	754.0	754.4	754.3	754.1	753.2
Average – Diluted	**758.5**	758.3	758.0	757.9	759.5	757.7	757.1	757.8	758.0	758.1
Price Range *($ per share)*										
TSX – C$										
High	**39.64**	35.69	36.25	36.68	39.64	38.98	37.11	38.38	38.98	38.90
Low	**30.09**	31.82	30.37	30.09	33.24	28.85	28.85	29.87	31.73	31.15
Close	**33.29**	33.29	34.31	32.37	35.90	33.83	33.83	32.27	36.40	38.30
NYSE - US$										
High	**39.81**	36.11	37.31	37.26	39.81	40.73	37.35	40.61	40.73	40.06
Low	**28.83**	31.74	30.20	28.83	32.45	27.15	27.15	29.02	32.48	31.11
Close	**33.54**	33.54	34.85	31.80	35.94	33.20	33.20	30.71	37.66	39.38
Dividends Paid *($ per share)*	**$ 0.88**	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ 0.80	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Share Volume Traded *(millions)*	**664.3**	141.7	152.6	192.6	177.4	873.7	213.3	239.8	215.9	204.7

NET CAPITAL INVESTMENT	2012					2011				
($ millions)	**Year**	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Oil Sands										
Foster Creek	**735**	208	199	169	159	429	139	110	77	103
Christina Lake	**579**	167	147	138	127	472	126	117	121	108
Total	**1,314**	375	346	307	286	901	265	227	198	211
Pelican Lake	**518**	147	128	104	139	317	132	70	31	84
Other Oil Sands	**379**	83	42	43	211	197	68	9	11	109
	2,211	605	516	454	636	1,415	465	306	240	404
Conventional	**848**	257	231	129	231	788	330	193	89	176
Refining and Marketing	**118**	58	38	24	(2)	393	73	101	117	102
Corporate	**191**	58	45	53	35	127	35	31	30	31
Capital Investment	**3,368**	978	830	660	900	2,723	903	631	476	713
Acquisitions [1]	**114**	70	8	28	8	71	49	1	2	19
Divestitures	**(76)**	(11)	–	1	(66)	(173)	(164)	–	(5)	(4)
Net Acquisition and Divestiture Activity	**38**	59	8	29	(58)	(102)	(115)	1	(3)	15
Net Capital Investment	**3,406**	1,037	838	689	842	2,621	788	632	473	728

(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

OPERATING STATISTICS – BEFORE ROYALTIES

UPSTREAM PRODUCTION VOLUMES	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands – Heavy Oil										
Foster Creek	**57,833**	59,059	63,245	51,740	57,214	54,868	55,045	56,322	50,373	57,744
Christina Lake	**31,903**	41,808	32,380	28,577	24,733	11,665	19,531	10,067	7,880	9,084
Total	**89,736**	100,867	95,625	80,317	81,947	66,533	74,576	66,389	58,253	66,828
Pelican Lake	**22,552**	23,507	23,539	22,410	20,730	20,424	20,558	20,363	19,427	21,360
	112,288	124,374	119,164	102,727	102,677	86,957	95,134	86,752	77,680	88,188
Conventional Liquids										
Heavy Oil	**16,015**	16,243	15,492	15,703	16,624	15,657	15,512	15,305	15,378	16,447
Light and Medium Oil	**36,071**	36,034	35,695	36,149	36,411	30,524	32,530	30,399	27,617	31,539
Natural Gas Liquids (1)	**1,029**	995	999	987	1,138	1,101	1,097	1,040	1,087	1,181
Total Crude Oil and Natural Gas Liquids	**165,403**	177,646	171,350	155,566	156,850	134,239	144,273	133,496	121,762	137,355
Natural Gas *(MMcf/d)*										
Oil Sands	**33**	30	27	33	41	37	38	39	37	32
Conventional (2)	**561**	536	550	563	595	619	622	617	617	620
Total Natural Gas	**594**	566	577	596	636	656	660	656	654	652

(1) Natural gas liquids include condensate volumes.

(2) In Q1 2012, a non-core natural gas property was divested, decreasing 2012 production approximately 3%.

AVERAGE ROYALTY RATES *(excluding impact of realized gain (loss) on risk management)*	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek	**11.8%**	8.0%	19.1%	4.6%	13.9%	16.8%	21.7%	20.6%	3.3%	21.2%
Christina Lake	**6.2%**	5.7%	5.3%	7.2%	7.0%	5.2%	4.7%	5.7%	6.3%	4.8%
Pelican Lake	**5.0%**	4.5%	6.6%	4.2%	4.5%	11.5%	9.1%	12.7%	9.7%	13.9%
Conventional										
Weyburn	**20.7%**	17.9%	19.8%	21.4%	23.3%	24.1%	24.8%	23.9%	23.6%	24.3%
Other	**7.2%**	7.1%	6.6%	6.8%	8.3%	8.3%	8.1%	9.0%	8.5%	7.6%
Natural Gas Liquids	**2.0%**	2.3%	2.5%	1.7%	1.7%	1.7%	1.8%	1.4%	2.3%	1.3%
Natural Gas	**1.2%**	0.9%	0.8%	0.4%	2.5%	1.7%	1.9%	1.5%	1.2%	2.3%

REFINING	2012					2011				
	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)*	**412**	311	442	451	445	401	424	413	406	362
Crude utilization	**91%**	69%	98%	100%	98%	89%	94%	91%	90%	80%
Refined products *(Mbbls/d)*	**433**	330	463	473	465	419	442	426	422	383

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

OPERATING STATISTICS – BEFORE ROYALTIES *(continued)*

SELECTED AVERAGE BENCHMARK PRICES	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
Brent Futures	**111.68**	110.13	109.42	108.76	118.45	110.91	109.02	112.09	116.99	105.52
West Texas Intermediate ("WTI")	**94.15**	88.23	92.20	93.35	103.03	95.11	94.06	89.54	102.34	94.60
Average Differential Brent Futures – WTI	**17.53**	21.90	17.22	15.41	15.42	15.80	14.96	22.55	14.65	10.92
Western Canadian Select ("WCS")	**73.12**	70.12	70.48	70.48	81.61	77.96	83.58	71.92	84.70	71.74
Differential – WTI-WCS	**21.03**	18.11	21.72	22.87	21.42	17.15	10.48	17.62	17.64	22.86
Condensate – (C5 @ Edmonton)	**100.88**	98.14	96.12	99.32	110.16	105.34	108.74	101.48	112.33	98.90
Differential – WTI-Condensate (premium)/discount	**(6.73)**	(9.91)	(3.92)	(5.97)	(7.13)	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)
Refining Margins 3-2-1 Crack Spreads (2) *(US$/bbl)*										
Chicago	**27.76**	28.18	35.64	28.20	19.00	24.55	19.23	33.35	29.00	16.62
Midwest Combined (Group 3)	**28.56**	28.49	35.99	28.28	21.50	25.26	20.75	34.04	27.19	19.04
Natural Gas Prices										
AECO *($/GJ)*	**2.28**	2.90	2.08	1.74	2.39	3.48	3.29	3.53	3.54	3.58
NYMEX *(US$/MMBtu)*	**2.79**	3.40	2.81	2.22	2.74	4.04	3.55	4.19	4.31	4.11
Differential – NYMEX/AECO *(US$/MMBtu)*	**0.38**	0.31	0.61	0.39	0.21	0.31	0.17	0.34	0.42	0.29

(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 regular unleaded gasoline and one barrel of ultra-low sulphur diesel, and reflect the current month WTI price as the crude oil feedstock price.

OPERATING STATISTICS – BEFORE ROYALTIES *(continued)*

PER-UNIT RESULTS *($, excluding impact of realized gain (loss) on risk management)*	2012					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek *($/bbl)*[3]										
Price	**64.55**	59.93	63.95	63.83	70.71	67.38	75.96	62.68	72.23	59.50
Royalties	**7.36**	4.55	11.79	2.85	9.54	10.82	15.81	12.38	2.30	11.92
Transportation and blending	**2.41**	2.91	2.38	1.91	2.38	3.04	3.20	2.73	2.82	3.41
Operating	**11.99**	11.26	11.50	12.49	12.85	11.34	11.31	11.11	11.57	11.40
Netback	**42.79**	41.21	38.28	46.58	45.94	42.18	45.64	36.46	55.54	32.77
Heavy Oil – Christina Lake *($/bbl)*[3]										
Price	**47.73**	43.37	52.91	44.57	52.58	61.86	66.69	54.52	67.06	54.67
Royalties	**2.72**	2.32	2.61	2.90	3.37	3.03	2.97	2.87	3.98	2.44
Transportation and blending	**3.79**	3.00	4.00	4.12	4.51	3.53	2.98	4.54	3.51	3.69
Operating	**12.95**	11.42	13.59	12.52	15.33	20.20	17.96	23.01	23.41	19.09
Netback	**28.27**	26.63	32.71	25.03	29.37	35.10	42.78	24.10	36.16	29.45
Heavy Oil – Pelican Lake *($/bbl)*[3]										
Price	**69.23**	64.37	66.75	66.42	78.50	73.07	88.67	66.76	78.26	64.66
Royalties	**3.34**	2.82	4.34	2.68	3.37	7.91	6.98	8.23	7.40	8.63
Transportation and blending	**2.15**	1.23	1.09	3.54	2.88	4.14	12.19	1.87	2.02	2.44
Operating	**17.08**	17.20	17.47	17.71	16.05	14.86	16.49	14.31	13.40	15.35
Netback	**46.66**	43.12	43.85	42.49	56.20	46.16	53.01	42.35	55.44	38.24
Heavy Oil – Oil Sands *($/bbl)*[3]										
Price	**60.84**	55.11	61.71	59.00	68.36	67.99	76.39	62.93	73.02	60.35
Royalties	**5.22**	3.47	7.85	2.83	6.66	9.17	11.72	10.46	3.65	10.08
Transportation and blending	**2.74**	2.63	2.52	2.87	2.99	3.36	4.75	2.68	2.71	3.18
Operating	**13.33**	12.41	13.29	13.61	14.18	13.27	13.54	13.02	13.27	13.23
Netback	**39.55**	36.60	38.05	39.69	44.53	42.19	46.38	36.77	53.39	33.86
Heavy Oil – Conventional *($/bbl)*[3]										
Price	**70.53**	64.73	68.04	67.70	80.64	74.17	81.49	67.96	78.47	69.17
Royalties	**10.06**	8.68	8.81	9.36	13.06	10.75	11.85	11.33	10.98	9.04
Transportation and blending	**2.17**	2.34	2.31	2.26	1.81	1.27	1.34	1.80	0.91	1.05
Operating	**15.21**	11.68	16.48	15.07	17.57	13.77	16.34	12.40	13.66	12.78
Production and mineral taxes	**0.24**	0.31	0.27	0.25	0.14	0.32	0.34	0.17	0.22	0.51
Netback	**42.85**	41.72	40.17	40.76	48.06	48.06	51.62	42.26	52.70	45.79
Total Heavy Oil *($/bbl)*[3]										
Price	**62.05**	56.22	62.45	60.13	70.08	68.98	77.16	63.69	73.98	61.80
Royalties	**5.83**	4.07	7.96	3.68	7.56	9.42	11.74	10.59	4.93	9.91
Transportation and blending	**2.67**	2.60	2.50	2.79	2.82	3.02	4.23	2.55	2.40	2.83
Operating	**13.56**	12.33	13.66	13.80	14.65	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	**0.03**	0.04	0.03	0.03	0.02	0.05	0.05	0.03	0.04	0.08
Netback	**39.96**	37.18	38.30	39.83	45.03	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil *($/bbl)*										
Price	**78.99**	75.27	76.06	76.16	88.45	85.40	90.90	79.57	94.30	77.39
Royalties	**8.09**	6.92	7.53	7.98	9.94	11.54	12.12	10.74	12.82	10.58
Transportation and blending	**2.65**	2.39	2.36	3.02	2.83	2.00	1.99	1.90	2.22	1.92
Operating	**15.51**	15.63	16.27	14.76	15.36	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	**2.44**	2.51	2.35	2.34	2.57	2.27	2.63	2.40	2.77	1.32
Netback	**50.30**	47.82	47.55	48.06	57.75	55.21	59.04	50.16	63.53	48.71

(3) The 2012 heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek – \$41.85/bbl; Christina Lake – \$45.83/bbl; Pelican Lake – \$15.55/bbl; Heavy Oil – Oil Sands – \$37.45/bbl; Heavy Oil – Conventional – \$13.35/bbl and Total Heavy Oil – \$34.44/bbl.

OPERATING STATISTICS – BEFORE ROYALTIES *(continued)*

PER-UNIT RESULTS

($, excluding impact of realized gain (loss) on risk management)	**2012**					2011				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil *($/bbl)*										
Price	**65.76**	60.10	65.37	63.91	74.22	72.80	80.49	67.37	78.71	65.32
Royalties	**6.32**	4.65	7.87	4.69	8.10	9.92	11.83	10.62	6.77	10.06
Transportation and blending	**2.66**	2.55	2.47	2.84	2.83	2.78	3.69	2.40	2.35	2.63
Operating	**13.99**	13.00	14.22	14.03	14.81	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	**0.56**	0.54	0.53	0.58	0.59	0.57	0.67	0.58	0.67	0.36
Netback	**42.23**	39.36	40.28	41.77	47.89	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids *($/bbl)*										
Price	**69.54**	65.89	61.53	65.52	83.36	76.84	82.26	74.38	80.32	70.67
Royalties	**1.42**	1.52	1.55	1.13	1.45	1.34	1.51	1.06	1.87	0.93
Netback	**68.12**	64.37	59.98	64.39	81.91	75.50	80.75	73.32	78.45	69.74
Total Liquids *($/bbl)*										
Price	**65.79**	60.13	65.35	63.92	74.28	72.84	80.50	67.43	78.72	65.37
Royalties	**6.29**	4.64	7.83	4.67	8.05	9.84	11.75	10.55	6.72	9.98
Transportation and blending	**2.65**	2.54	2.45	2.82	2.81	2.76	3.66	2.38	2.33	2.60
Operating	**13.90**	12.93	14.14	13.93	14.71	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	**0.56**	0.54	0.53	0.57	0.59	0.56	0.67	0.57	0.67	0.36
Netback	**42.39**	39.48	40.40	41.93	48.12	46.21	50.29	40.77	55.87	39.00
Total Natural Gas *($/Mcf)*										
Price	**2.42**	2.97	2.30	1.92	2.50	3.65	3.35	3.72	3.71	3.82
Royalties	**0.03**	0.02	0.02	0.01	0.06	0.06	0.06	0.05	0.04	0.08
Transportation and blending	**0.10**	0.10	0.08	0.08	0.13	0.15	0.14	0.15	0.14	0.17
Operating	**1.10**	1.29	1.08	0.98	1.08	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	**0.01**	(0.01)	0.02	0.02	0.02	0.04	0.01	0.03	0.05	0.06
Netback	**1.18**	1.57	1.10	0.83	1.21	2.30	1.92	2.50	2.50	2.32
Total *($/BOE)* (2)										
Price	**46.60**	45.50	46.61	43.25	50.84	49.75	53.48	46.97	51.81	46.83
Royalties	**4.00**	3.08	5.02	2.84	5.00	5.55	6.65	5.91	3.64	5.85
Transportation and blending	**1.88**	1.86	1.74	1.90	2.00	1.91	2.39	1.70	1.61	1.92
Operating (1)	**11.18**	11.12	11.35	10.75	11.46	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	**0.38**	0.33	0.38	0.40	0.40	0.41	0.40	0.39	0.49	0.36
Netback	**29.16**	29.11	28.12	27.36	31.98	31.53	32.95	29.09	36.38	28.02

(1) 2012 operating costs include costs related to long-term incentives of $0.16/BOE (2011 – $0.17/BOE).

IMPACT OF REALIZED GAIN (LOSS) ON RISK MANAGEMENT

Liquids *($/bbl)*	**1.39**	3.35	2.02	1.64	(1.67)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas *($/Mcf)*	**1.14**	0.89	1.24	1.39	1.03	0.87	1.10	0.76	0.74	0.89
Total *($/BOE)* (2)	**3.42**	4.05	3.98	4.27	1.44	0.86	1.22	2.49	(1.25)	0.83

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). 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.

ADDITIONAL RESERVES AND OIL AND GAS INFORMATION

For information in relation to the presentation of our reserves data and other oil and gas information, see "Oil and Gas Reserves and Resources" in our MD&A. We hold significant fee 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 terms used in our oil and gas disclosure, please refer to the Advisory.

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", "Risk Factors – Uncertainty of Reserves and Future Net Revenue Estimates" and "Risk Factors – Uncertainty of Contingent and Prospective Resource Estimates", each within our Annual Information Form for the year ended December 31, 2012, available on our website at www.cenovus.com.

SUMMARY OF COMPANY INTEREST OIL AND GAS RESERVES AT DECEMBER 31, 2012

(Forecast Prices and Costs)

Before Royalties[1]

Reserves Category	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
Proved Reserves				
Developed Producing	172	121	84	917
Developed Non-Producing	13	1	9	32
Undeveloped	1,532	62	22	6
Total Proved Reserves	1,717	184	115	955
Probable Reserves	676	105	56	338
Total Proved plus Probable Reserves	2,393	289	171	1,293

(1) Does not include Royalty Interest Reserves.

After Royalties[2]

Reserves Category	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
Proved Reserves				
Developed Producing	134	102	73	930
Developed Non-Producing	10	1	7	31
Undeveloped	1,149	51	18	6
Total Proved Reserves	1,293	154	98	967
Probable Reserves	499	79	46	324
Total Proved plus Probable Reserves	1,792	233	144	1,291

(2) Includes Royalty Interest Reserves.

Royalty Interest

Reserves Category	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
Proved Reserves				
Developed Producing	–	1	4	43
Developed Non-Producing	–	–	–	–
Undeveloped	–	–	–	–
Total Proved Reserves	–	1	4	43
Probable Reserves	–	1	2	13
Total Proved plus Probable Reserves	–	2	6	56

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AT DECEMBER 31, 2012

(Forecast Prices and Costs)

Before Income Taxes

	Discounted at %/year *($ millions)*					Unit Value Discounted at 10% (1)
Reserves Category	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	14,927	12,313	10,485	9,155	8,149	22.62
Developed Non-Producing	1,048	762	592	480	401	24.90
Undeveloped	50,592	24,053	12,798	7,301	4,313	10.50
Total Proved Reserves	66,567	37,128	23,875	16,936	12,863	13.99
Probable Reserves	31,347	14,385	7,635	4,598	3,055	11.25
Total Proved plus Probable Reserves	97,914	51,513	31,510	21,534	15,918	13.21

(1) Unit values have been calculated using Company Interest After Royalties reserves.

After Income Taxes(1)

	Discounted at %/year *($ millions)*				
Reserves Category	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	11,990	9,951	8,510	7,457	6,658
Developed Non-Producing	788	574	447	364	306
Undeveloped	37,993	17,835	9,342	5,219	2,993
Total Proved Reserves	50,771	28,360	18,299	13,040	9,957
Probable Reserves	23,465	10,675	5,623	3,362	2,218
Total Proved plus Probable Reserves	74,236	39,035	23,922	16,402	12,175

(1) Values are calculated by considering existing tax pools and tax circumstances for Cenovus and its subsidiaries in the consolidated evaluation of Cenovus's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see our Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2012.

The estimates of future net revenue do not represent fair market value.

RESERVES RECONCILIATION

The following tables provide a reconciliation of our Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2012, presented using forecast prices and costs. All reserves are located in Canada.

COMPANY INTEREST BEFORE ROYALTIES

RESERVES RECONCILIATION BY PRINCIPAL PRODUCT TYPE AND RESERVES CATEGORY

(Forecast Prices and Costs)

Proved

	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2011	1,455	175	115	1,203
Extensions and Improved Recovery	265	17	13	29
Discoveries	–	–	–	–
Technical Revisions	30	6	(2)	51
Economic Factors	–	–	–	(58)
Acquisitions	–	–	1	1
Dispositions	–	–	–	(59)
Production(1)	(33)	(14)	(12)	(212)
December 31, 2012	1,717	184	115	955

Probable

	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2011	490	109	51	391
Extensions and Improved Recovery	140	11	5	8
Discoveries	–	–	–	–
Technical Revisions	46	(15)	–	(30)
Economic Factors	–	–	–	(4)
Acquisitions	–	–	–	–
Dispositions	–	–	–	(27)
Production(1)	–	–	–	–
December 31, 2012	676	105	56	338

Proved plus Probable

	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2011	1,945	284	166	1,594
Extensions and Improved Recovery	405	28	18	37
Discoveries	–	–	–	–
Technical Revisions	76	(9)	(2)	21
Economic Factors	–	–	–	(62)
Acquisitions	–	–	1	1
Dispositions	–	–	–	(86)
Production(1)	(33)	(14)	(12)	(212)
December 31, 2012	2,393	289	171	1,293

(1) Production used for the reserves reconciliation differs from publicly reported production. In accordance with NI 51-101, Company Interest Before Royalties production used for the reserves reconciliation above includes our share of gas volumes provided to the FCCL partnership for steam generation, but does not include Royalty Interest Production.

Bitumen Economic Contingent and Prospective Resources

Company Interest Before Royalties, Billions of barrels	**December 31, 2012**	December 31, 2011
Economic Contingent Resources[1]		
Low Estimate	**7.1**	6.0
Best Estimate	**9.6**	8.2
High Estimate	**12.8**	10.8
Prospective Resources[2]		
Low Estimate	**5.0**	5.7
Best Estimate	**8.5**	10.0
High Estimate	**14.8**	17.9

(1) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) 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
2012:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	8	7	–	–	–	–	8	7	20	28	7
Total Canada	8	7	–	–	–	–	8	7	20	28	7
2011:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	24	22	–	–	2	2	26	24	40	66	24
Total Canada	24	22	–	–	2	2	26	24	40	66	24
2010:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	26	26	–	–	1	1	27	27	21	48	27
Total Canada	26	26	–	–	1	1	27	27	21	48	27

Development Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2012:											
Oil Sands	137	107	–	–	–	–	137	107	57	194	107
Conventional	273	268	–	–	1	1	274	269	129	403	269
Total Canada	410	375	–	–	1	1	411	376	186	597	376
2011:											
Oil Sands	71	51	3	3	–	–	74	54	87	161	54
Conventional	312	303	66	65	4	4	382	372	156	538	372
Total Canada	383	354	69	68	4	4	456	426	243	699	426
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

During the year ended December 31, 2012, Oil Sands drilled 473 gross stratigraphic test wells (317 net wells) and Conventional drilled 14 gross stratigraphic test wells (14 net wells).

During the year ended December 31, 2012, Oil Sands drilled 116 gross service wells (112 net wells) and Conventional drilled 22 gross service wells (16 net wells).

For all types of wells except stratigraphic test wells, the calculation of the number of wells is based on the number of surface locations. For stratigraphic test wells, the calculation is based on the number of bottomhole locations.

Interest in Material Properties

The following table summarizes our landholdings at December 31, 2012:

Landholdings	Developed		Undeveloped(1)		Total(2)	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown(3)	582	487	2,256	1,792	2,838	2,279
Conventional						
– Fee(4)	1,931	1,931	442	442	2,373	2,373
– Crown(3)	1,011	910	311	261	1,322	1,171
– Freehold(5)	71	60	18	16	89	76
Total Alberta	3,595	3,388	3,027	2,511	6,622	5,899
Saskatchewan:						
Conventional						
– Fee(4)	78	78	427	427	505	505
– Crown(3)	71	57	291	273	362	330
– Freehold(5)	14	9	11	7	25	16
Total Saskatchewan	163	144	729	707	892	851
Manitoba:						
Conventional – Fee(4)	4	4	262	262	266	266
Total Manitoba	4	4	262	262	266	266
Total	3,762	3,536	4,018	3,480	7,780	7,016

(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 includes all freehold 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.

ADVISORY

FINANCIAL INFORMATION

Basis of Presentation Financial information in our Annual Report is in Canadian dollars, except where another currency has been indicated and has been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

Non-GAAP Measures Certain financial measures in our Annual Report do not have a standardized meaning as prescribed by IFRS, such as operating cash flow, cash flow, operating earnings, free cash flow, debt, capitalization and adjusted EBITDA, 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 order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections in our MD&A.

FORWARD-LOOKING INFORMATION

This document 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 document 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, expected future refining capacity, 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, future impact of regulatory measures, 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 our 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; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; 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 assumptions on which our 2013 guidance is based include: Brent US$100.00/bbl, WTI of US$91.00/bbl; Western Canada Select of US$63.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.40/GJ; Chicago 3-2-1 crack spread of US$20.00/bbl; exchange rate of $1.00 US$/C$; and an average diluted number of shares outstanding of approximately 766 million. The assumptions on which our forecasts for the period 2014 to 2021 are based on include: WTI of US$90.00-US$105.00/bbl; Western Canada Select of US$75.00-US$85.00/bbl; NYMEX of US$5.25-US$6.00/MMBtu; AECO of $4.50-$5.25/GJ; Chicago 3-2-1 crack spread of US$9.00; exchange rate of $1.00-$1.07 US$/C$; and an average diluted number of shares outstanding of approximately 769 million.

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 the success of our hedging strategies; the 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 desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners 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 producing, transporting or refining of crude oil into petroleum and chemical products; 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 the regulatory framework in any of the locations in which we operate, 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 for the year ended December 31, 2012 (see Additional Information).

OIL AND GAS INFORMATION

Terminology The estimates of reserves and resources data and related information were prepared effective December 31, 2012 by independent qualified reserves evaluators ("IQREs") and are presented using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2013 price forecast. We hold significant fee title rights which generate production for our account from third parties leasing those lands.

For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2012 (see Additional Information). The following definitions are applicable to our oil and gas disclosure in our Annual Report:

After Royalties means volumes after deduction of royalties and includes Royalty Interests.

Before Royalties means volumes before deduction of royalties and excludes Royalty Interests.

Company Interest means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by us.

Gross means: (a) in relation to wells, the total number of wells in which we have an interest; and (b) in relation to properties, the total area of properties in which we have an interest.

Net means: (a) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and (b) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

Reserves terminology:

Reserves are estimated remaining quantities anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions. Reserves are classified according to the degree of certainty associated with the estimates:

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories above may be divided into developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided as follows:

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. similar to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Royalty Interest Reserves means those reserves related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any reserves related to other royalty interests, such as overriding royalties, to which we are entitled.

Royalty Interest Production means the production related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any production related to other royalty interests, such as overriding royalties, to which we are entitled.

Resources terminology:

Contingent resources are those quantities of bitumen 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. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The McDaniel estimates of contingent resources have 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.

The economic contingent resources were estimated for individual projects and then aggregated for disclosure purposes. The high and low estimate volumes are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. Because the results are aggregated for disclosure, the low estimate results disclosed may have a higher probability than the estimates for the individual projects, and the high estimate results disclosed may have a lower probability than the estimates for individual projects.

Prospective resources are those quantities of bitumen 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 probability 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 included in the low estimate range have the highest degree of certainty – a 90 percent probability – 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 included in the high estimate range have a lower degree of certainty, a 10 percent probability, that the actual quantities recovered will equal or exceed the estimate.

Barrels of Oil Equivalent 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.

Finding and Development Costs Finding and development costs disclosed in our Annual Report do not include the change in estimated future development costs. 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 for *proved reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $25.48/BOE for the year ended December 31, 2012, $13.99/BOE for the year ended December 31, 2011 and averaged $16.35/BOE for the three years ended December 31, 2012. 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 $20.04/BOE for the year ended December 31, 2012, $10.69/BOE for the year ended December 31, 2011 and averaged $14.27/BOE for the three years ended December 31, 2012. 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 period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period and the change during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

For additional information about our finding and development costs, capital investment and reserves additions, see our February 14, 2013 news release available on our website at www.cenovus.com.

Net Asset Value With respect to the particular year being valued, the net asset value (NAV) disclosed herein is based on the number of issued and outstanding Cenovus shares as at December 31 as reported in our Annual Information Form and Form 40-F, plus the total dilutive effect of Cenovus shares related to stock option programs or other contracts as disclosed in the "Per Share Amounts" note to our annual Consolidated Financial Statements. We calculate NAV as an average of (i) our average trading price for the month of December, (ii) an average of net asset values published by external analysts in December following the announcement of our budget forecast, and (iii) an average of two net asset values based primarily on discounted cash flows of independently evaluated reserves, resources and refining data and using internal corporate costs, with one based on constant prices and costs and one based on forecast prices and costs.

ABBREVIATIONS

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

TM	Trademark of Cenovus Energy Inc.

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 Canadian Select

Natural Gas

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

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, including our Annual Information Form / Form 40-F for the year ended December 31, 2012, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

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

Sheila M. McIntosh
Executive Vice-President,
Environment & Corporate Affairs

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

CENOVUS HEAD OFFICE

Cenovus Energy Inc.
500 Centre Street SE
PO Box 766
Calgary, Alberta, Canada
T2P 0M5
Phone: 403.766.2000
cenovus.com

BOARD OF DIRECTORS

Michael A. Grandin(3)(7)
Chair, Calgary, Alberta

Ralph S. Cunningham(2)(3)(5)
Houston, Texas

Patrick D. Daniel(1)(2)(3)
Calgary, Alberta

Ian W. Delaney(2)(3)(5)
Toronto, Ontario

Brian C. Ferguson(6)
Calgary, Alberta

Valerie A.A. Nielsen(1)(3)(4)
Calgary, Alberta

Charles M. Rampacek(3)(4)(5)
Dallas, Texas

Colin Taylor(1)(2)(3)
Toronto, Ontario

Wayne G. Thomson(3)(4)(5)
Calgary, Alberta

(1) Member of the Audit Committee.

(2) Member of the Human Resources and Compensation Committee.

(3) Member of the Nominating and Corporate Governance Committee.

(4) Member of the Reserves Committee.

(5) Member of the Safety, Environment and Responsibility Committee.

(6) As an officer and a non-independent director, Mr. Ferguson is not a member of any Board Committees.

(7) Ex-officio non-voting member of all other Board Committees.

SHAREHOLDER INFORMATION

ANNUAL MEETING

Shareholders are invited to attend the annual meeting to be held on Wednesday, April 24, 2013 at 2 p.m. (Calgary time) at The Westin Calgary, Grand Ballroom, 320 – 4 Avenue SW, Calgary, Alberta, Canada.

Please see our management proxy circular available on our website, cenovus.com, for additional information.

TRANSFER AGENTS & REGISTRAR

Computershare Investor Services Inc.
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
www.investorcentre.com/cenovus

Shareholder inquiries by phone 1.866.332.8898 (North America, English & French) or 1.514.982.8717 (outside North America).

SHAREHOLDER ACCOUNT MATTERS

For information regarding your shareholdings or to change your address, transfer shares, eliminate duplicate mailings, direct deposit of dividends, etc., please contact Computershare Investor Services Inc.

STOCK EXCHANGES

Cenovus common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol CVE.

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 US Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as an Annual Report on Form 40-F on EDGAR at www.sec.gov.

NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the 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, 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 cenovus.com for investor information.

Investor inquiries should be directed to:
403.766.7711
investor.relations@cenovus.com

Media inquiries should be directed to:
403.766.7751
media.relations@cenovus.com

Cenovus Energy is a Canadian integrated oil company. We are committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs.

Our operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface. As well, we have established natural gas and oil production in Alberta and Saskatchewan. We also have 50 percent ownership in two U.S. refineries.

CENOVUS.COM

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500 Centre Street SE
PO Box 766
Calgary, Alberta T2P 0M5

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