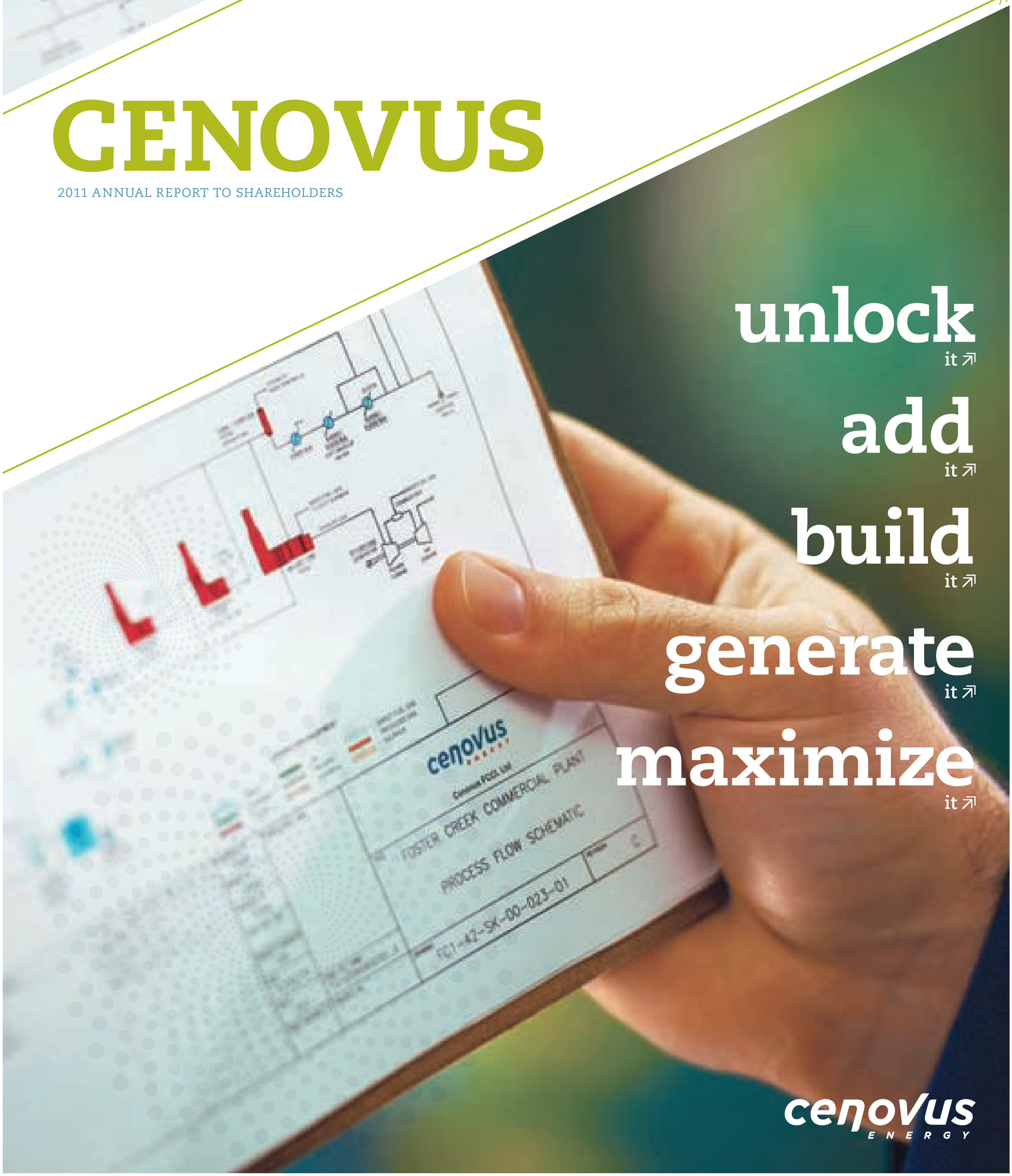
CENOVUS 2011 ANNUAL REPORT

CENOVUS

2011 ANNUAL REPORT TO SHAREHOLDERS



unlock it

add it

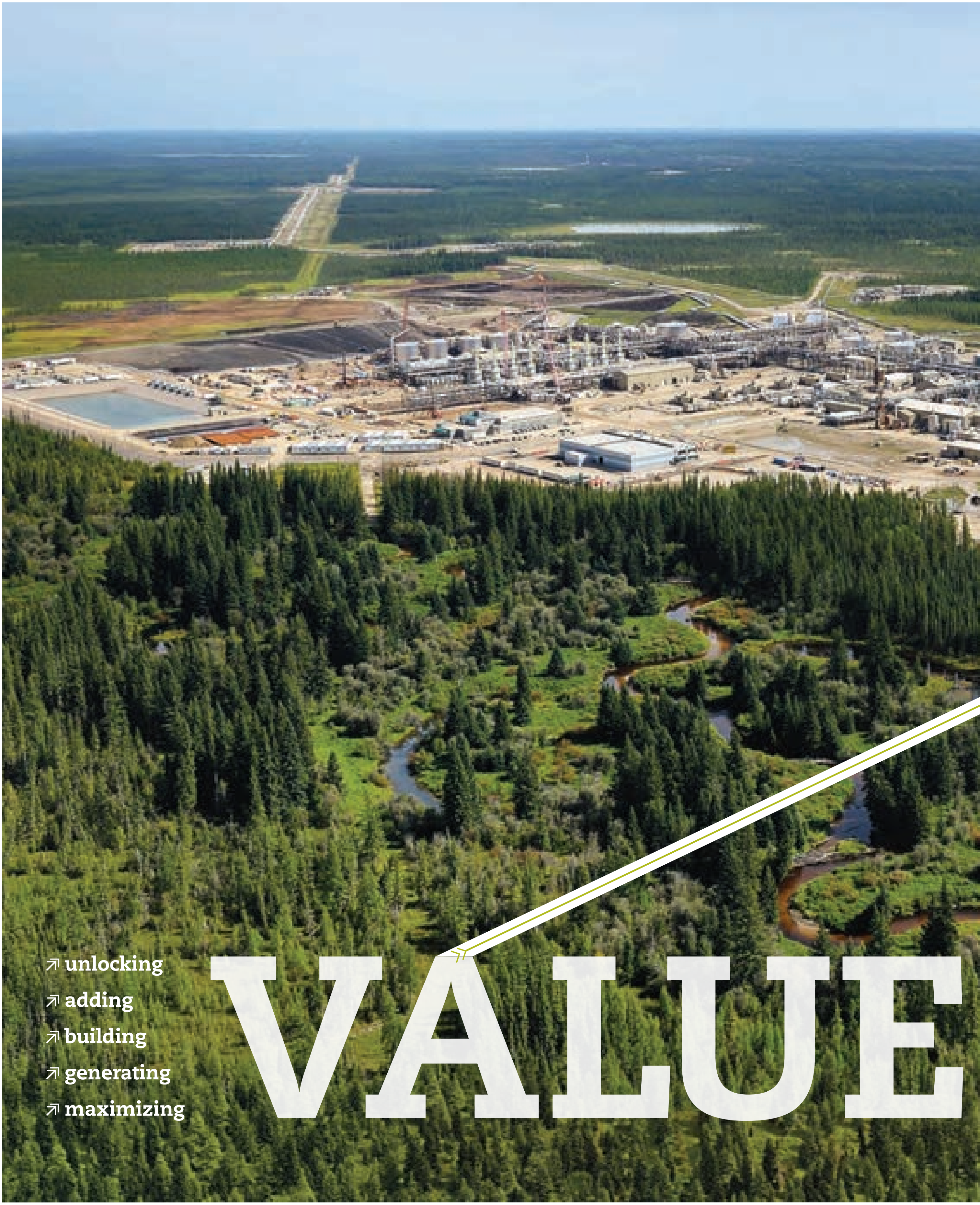
build it

generate it

maximize it

cenovus ENERGY

cenovus.com


↗ unlocking
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↗ generating
↗ maximizing
VALUE

Building a strong foundation for continued growth
was our focus in 2011.

We are a Canadian oil company applying fresh, progressive thinking:
To safely and responsibly unlock energy resources the world needs – that's our promise.
To increase total shareholder return – that's our goal.

We have a top-quality resource that is expected to produce oil for generations, a solid strategy and a track record of strong results. As a team, we're passionate about operational excellence, committed to finding better ways of doing things and respectful of the environment and the communities where we live and work.

We are continuing to grow responsibly and create value for our shareholders.

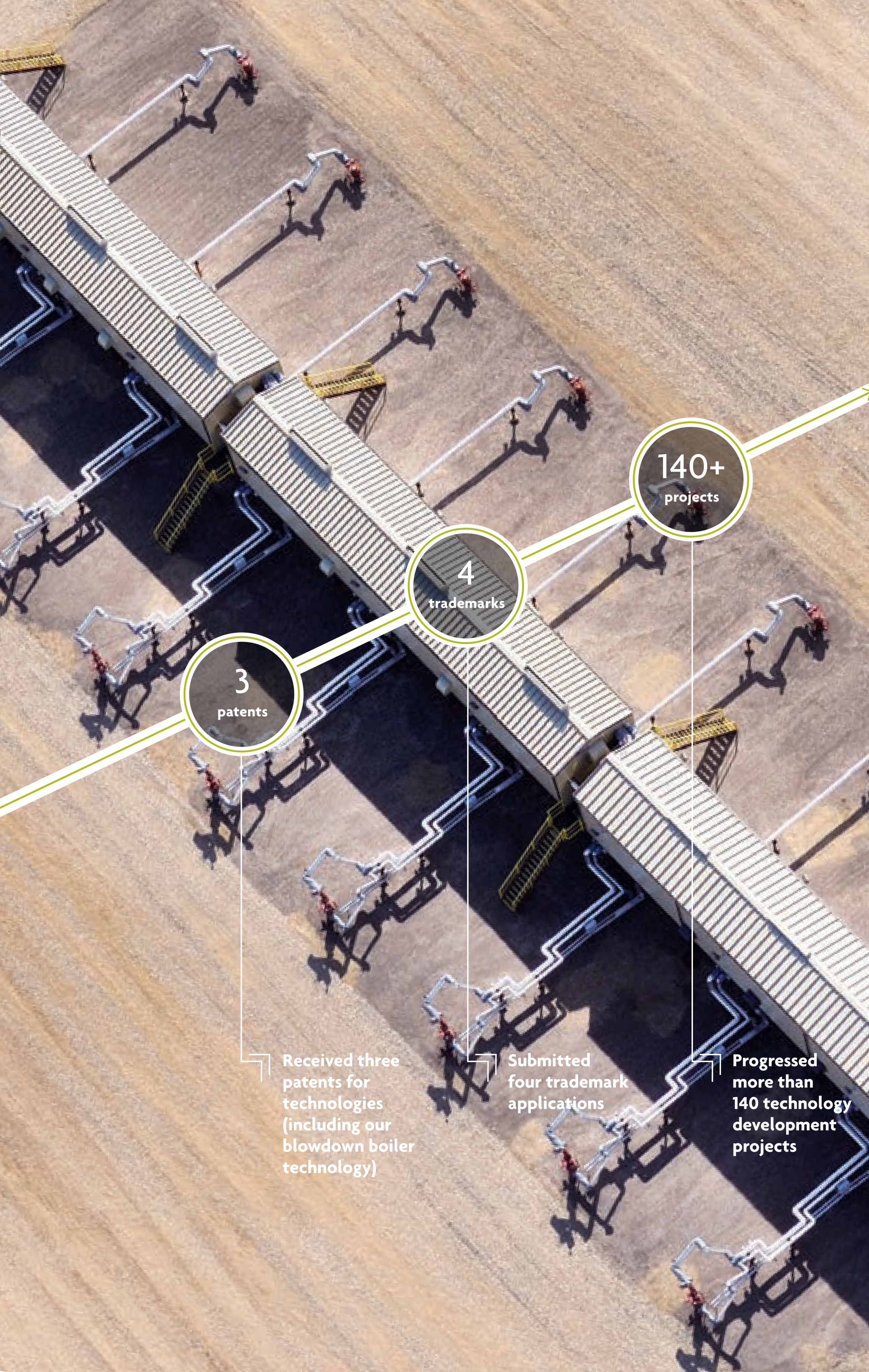
DRILLING IN THE OIL SANDS *Our Christina Lake project, pictured here, is located in northern Alberta, about 120 kilometres south of Fort McMurray. It's one of our industry-leading oil sands projects where we use steam-assisted gravity drainage (SAGD) technology. Learn more about SAGD on page 22/23 foldout.*

UNLOCKING VALUE THROUGH

leading technology

We have a culture that fosters new ideas and new approaches, and a track record of developing innovative solutions that unlock previously inaccessible resources. These solutions add value to our business and improve our environmental performance.

MAKING IMPROVEMENTS *This SAGD well pad at our Foster Creek project uses electric pumps underground in the wells to bring oil to the surface. We've been able to improve the SAGD process by using these pumps instead of a natural gas lift system. These electric submersible pumps reduce our steam to oil ratio (the amount of steam used to produce a barrel of oil), which means less water use, lower emissions and lower operating costs per barrel of oil recovered.*


3
patents
4
trademarks
140+
projects
Received three patents for technologies (including our blowdown boiler technology)
Submitted four trademark applications
Progressed more than 140 technology development projects

ADDING VALUE THROUGH

our dedicated people

Our teams are enthusiastic and dedicated to improving every aspect of our business. We are experienced at turning ideas into action and committed to doing right by the environment and the communities where we live and work. We are building a work environment that has the right people with the right attitude and the right skills, working in the right culture.

SHARING KNOWLEDGE *We held an Innovation Summit for our people to share ideas and information, to inspire each other and to apply what they learned. The two-day event brought employees and contractors together from all areas of the company to help drive improvements across our business.*


Held inaugural Innovation Summit
Welcomed 700 people to the company to help execute growth plans
Increased focus on employee development
Updated employees via company-wide forums

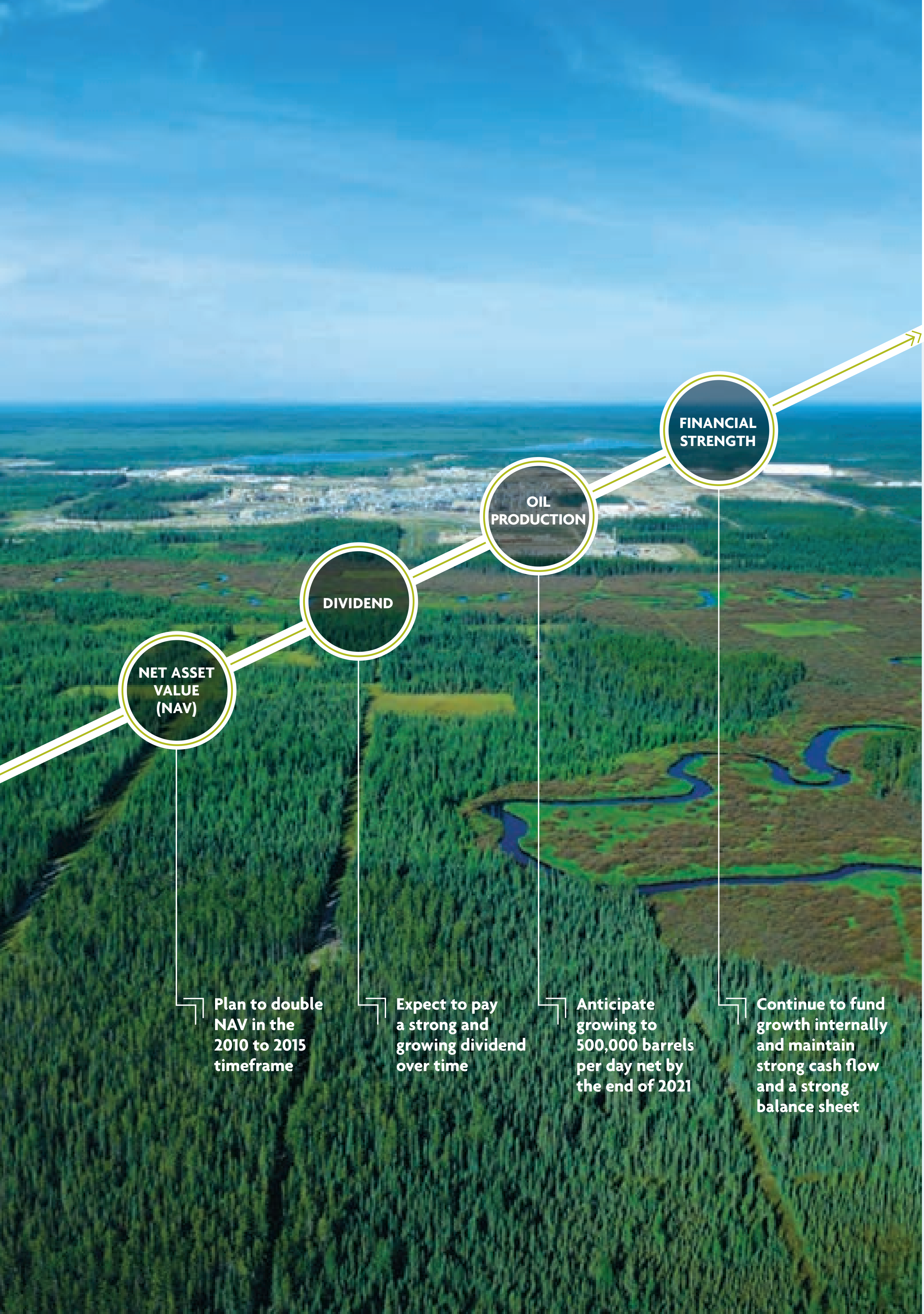
BUILDING VALUE THROUGH

a solid strategy

Our strategy defines our focus for the next decade. It is centred on developing our top-quality oil resources, building on our track record of strong project execution, progressing our environmental performance, expanding our markets and maintaining our financial strength – all aimed at increasing total shareholder return. We are building on our success in a consistent, predictable and reliable way.

See how we did in 2011 (page 15).

ADVANCING PROJECTS *Our oil sands projects are a key part of our growth strategy. We build them in phases so we can apply what we learn from one phase to the next. Our Foster Creek project, pictured here, has five phases in operation, with three more under construction.*

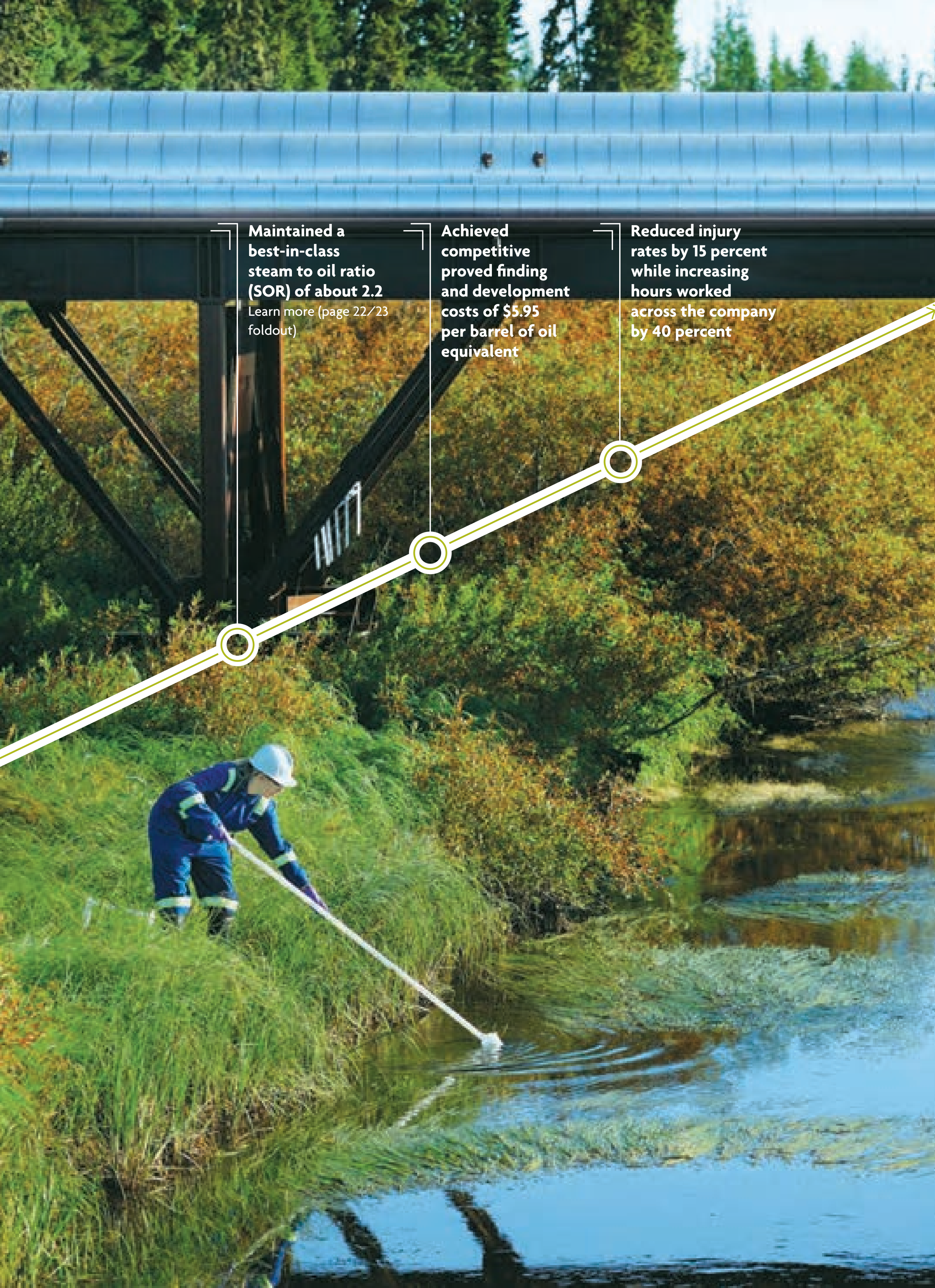

NET ASSET VALUE (NAV)
DIVIDEND
OIL PRODUCTION
FINANCIAL STRENGTH
Plan to double NAV in the 2010 to 2015 timeframe
Expect to pay a strong and growing dividend over time
Anticipate growing to 500,000 barrels per day net by the end of 2021
Continue to fund growth internally and maintain strong cash flow and a strong balance sheet

GENERATING VALUE THROUGH

smart resource development

We take our commitment to smart resource development seriously. Our manufacturing approach to developing oil sands resources allows us to improve efficiencies and reduce costs while maintaining our commitment to safe operations and environmental progress. It’s this approach, combined with the exceptional quality of our oil sands reservoirs, that helps make Cenovus an industry leader.

OPERATING RESPONSIBLY *As a routine part of our operations we monitor environmental conditions. For example, we regularly test the bodies of water located near our oil sands projects.*



Maintained a best-in-class steam to oil ratio (SOR) of about 2.2
Learn more (page 22/23 foldout)

Achieved competitive proved finding and development costs of $5.95 per barrel of oil equivalent

Reduced injury rates by 15 percent while increasing hours worked across the company by 40 percent

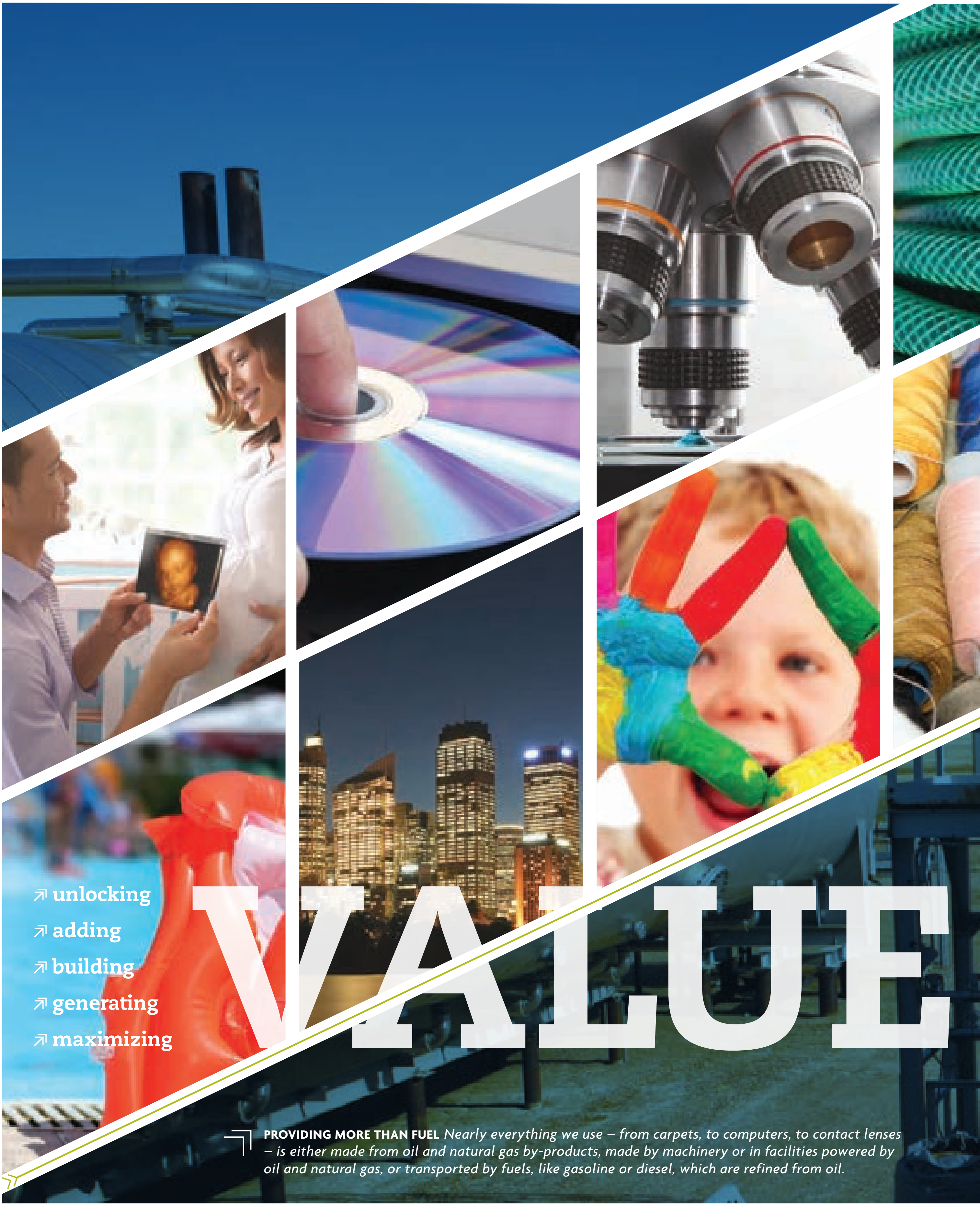
MAXIMIZING VALUE THROUGH

our integrated approach

All oil – whether it's light, medium or heavy – needs to be refined once it's out of the ground so it can be made into usable products. Through our 50 percent ownership in two oil refineries in the U.S. – Wood River, located in Illinois, and Borger, located in Texas – we capture the full value from crude oil production through to refined products such as gasoline, diesel and jet fuel. Our low-cost natural gas operations, which we consider financial assets, 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.

INCREASING CAPACITY *The recently completed coker at our Wood River Refinery in Illinois supports our integration strategy and growth plans. The coker and refinery expansion (CORE) doubles Wood River's heavy crude oil refining capacity and increases the amount of transportation fuels produced.*


Completed coker construction and start up of the CORE project at Wood River Refinery
Increased total Canadian heavy crude oil processing capacity to between 200,000 barrels per day and 220,000 barrels per day
Produced more than 650 million cubic feet of natural gas per day, offsetting internal consumption of 110 million cubic feet per day from our oil and refining operations



- unlocking
- adding
- building
- generating
- maximizing

VALUE

PROVIDING MORE THAN FUEL *Nearly everything we use – from carpets, to computers, to contact lenses – is either made from oil and natural gas by-products, made by machinery or in facilities powered by oil and natural gas, or transported by fuels, like gasoline or diesel, which are refined from oil.*

Oil and natural gas are more than just sources of fuel. They contribute to the building blocks of thousands of products we use and rely on every day. Products that make a positive difference in our lives.

We're proud of the way we develop the resources that provide such value. And we're proud of the role we play in making people's lives a little easier and a little better.

INCREASING VALUE BY

achieving our milestones

We’re delivering on our 10-year business plan which is focused on increasing total shareholder return. 2011 was an excellent year, a year in which we met or exceeded every milestone we set. The reason we set specific milestones is so we can measure our achievements and you can track our progress.

2011 milestones

All milestones were met or exceeded

- **Grow reserves and contingent resources**
  Increased best estimate bitumen economic contingent resources by 34 percent to 8.2 billion barrels
  Added proved reserves of 366 million barrels of oil equivalent
- **Drill 450 stratigraphic test wells and assess results**
  Completed largest stratigraphic test well drilling program we have ever undertaken with 480 oil sands wells and 11 conventional wells
- **Sanction Foster Creek phases F, G & H**
  Initiated site construction on these phases
- **Achieve first production at Christina Lake phase C**
  Completed ahead of schedule and under budget
- **Receive regulatory approval for Christina Lake phases E, F & G and commence sanctioning process for E**
  Began construction on phase E and initiated site preparation on phase F
- **Expand the polymer flood and drill additional infill wells at Pelican Lake, which is expected to result in higher production**
  Drilled 31 infill wells
- **Submit revised Telephone Lake application**
  Increased expected production capacity to 90,000 barrels per day from 35,000 barrels per day
- **Achieve first production at Grand Rapids pilot and submit regulatory application for commercial operation with production capacity of up to 180,000 barrels per day**
- **Start up coker as part of Wood River CORE project**
  Doubled heavy oil processing capacity
- **Implement the Cenovus Operations Management System**
  Resulted in company-wide framework of operations practices and processes
- **Implement at least one new commercial technology**
  Commercialized our patented blowdown boiler technology
- **Advance environment key performance indicators and long-term impact forecasting**
  Progressed with a focus on fresh water, carbon emissions and land reclamation
- **Integrate the six commitment areas of our Corporate Responsibility Policy into the business in order to create value for both our company and the communities where we live and work**

2012 milestones

Milestones set so far

- 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 and commence sanctioning process for Narrows Lake
  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 CORE operation at Wood River Refinery
- Advance value creation from Telephone Lake asset
- Develop tailored business unit environmental performance strategies

LOOKING AHEAD *Our Christina Lake project, pictured left, is on track for continued growth. Substantial construction was completed for phases D and E and site preparation progressed for phase F. We also submitted an application to add co-generation facilities. The application includes a gross production capacity increase at both phases F and G to 50,000 barrels per day from 40,000 barrels per day.*

CREATING VALUE BY

delivering

"The men and women who make up Cenovus have once again surpassed my expectations. I am extremely proud of what our teams have accomplished in this, our second year as an independent oil company. We are well on our way to achieving our 10-year business plan."

A STRONG FOUNDATION FOR CONTINUED GROWTH

Over the course of 2011, we met or exceeded every milestone we set for ourselves. We proved once again that you can count on us to develop our resources safely and responsibly, and to advance our projects in a consistent, predictable and reliable manner. All while striving to be better at how we do it.

It was a year with great operational results, tremendous reserves and resources growth and excellent financial performance. A year in which we continued the momentum of 2010 and laid the foundation for new opportunities and decades of growth in front of us.

Our strategy is centred on developing our vast oil assets and on continuing to bring forward the value of our tremendous resource base. In 2011, we updated our 10-year business plan to expand oil sands and also conventional oil opportunities. We now expect to reach about 500,000 barrels per day of net oil production by the end of 2021.

We made significant progress in 2011. Oil sands production at Foster Creek and Christina Lake increased 13 percent over 2010. We advanced timelines for future phases at both these projects and completed our 2011 stratigraphic test well program to continue unlocking even more value from our oil sands assets. We also strategically increased investments in areas of conventional oil growth, including Pelican Lake and tight oil properties in southern Saskatchewan. As a result of our activity, we increased our total proved reserves by 17 percent and our best estimate bitumen economic contingent resources by 34 percent in 2011 compared with 2010.

The success we achieved in our oil and gas operations was complemented by success in our refining business in 2011. We not only completed the multi-year expansion project at our Wood River Refinery in Illinois, but also delivered strong cash flow from our refining business overall. With our integrated business model we are able to mitigate risk of commodity price fluctuations to our cash flow over the long-term. In 2011, oil production growth across our operations, combined with strong oil prices and excellent financial results from

"Over the course of 2011, we met or exceeded every milestone we set for ourselves. We proved once again that you can count on us to develop our resources safely and responsibly, and to advance our projects in a consistent, predictable and reliable manner."

both our refining business and our low-cost natural gas assets, generated total cash flow of almost $3.3 billion or $4.32 per share on a fully diluted basis – an increase of 36 percent compared with 2010.

We also strengthened our balance sheet and our financial capacity in 2011, ending the year with a debt to capitalization ratio of 27 percent and a debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) of 1.0 times, which are at or below our long-term targeted ranges. We are funding our growth plans while providing a dividend to you, our shareholders – one that we increased by 10 percent to $0.22 per share for the first quarter of 2012. We expect ongoing financial strength will allow us to place a priority on continuing to grow the dividend over time.

Each year we identify key milestones, so our shareholders can track our progress. The 2011 milestones are listed on page 15 of this report. As you will see, every one of them has a check mark. In addition, we set five areas of focus in 2011 to guide our work. That clarity enabled us not only to deliver on all our commitments, but also to continue maximizing value.

OUR FIVE AREAS OF FOCUS

1. Execution: Delivering on our growth commitments

We remained focused on delivering strong performance in 2011 and on successfully achieving the goals we had set for ourselves.

We continued to develop our major oil sands assets. We brought the 40,000 barrel per day phase C expansion on at Christina Lake under budget and ahead of schedule, which should allow us to reach full capacity by mid-2012 and advance start up of the next expansion phase. Between Foster Creek and Christina Lake, we have now commissioned eight phases totalling 178,000 barrels per day of gross production capacity. We have another seven phases under construction, approved by regulators or sanctioned by our partner, ConocoPhillips, which will add an additional 285,000 barrels per day of gross production capacity by 2017. Add to that our expected increase in conventional oil production and you can see that we're well on our way to achieving our longer-term production goals.

As our heavy oil production is increasing, we also increased our heavy oil processing capacity in a cost-efficient manner at the Wood River Refinery, a location already served by existing pipelines. We added new capacity this past year at Wood River with the successful completion of coker construction and start up of the coker and refinery expansion (CORE) project.

Getting our oil to market is an essential consideration as our production grows – it's all about access. Within the next 10 years we expect to be marketing over one million barrels of oil per day on behalf of ourselves and our partner. Our marketing and transportation strategies are developed to support our production growth strategy and our approach is to ensure we always have transportation options. Along with a number of other producer companies, we support the Northern Gateway Pipeline, and we're supportive of all pipeline projects that would open up access to new markets for Canadian oil. In late 2011, we took a small but important step in building new markets in California and Asia through a service commitment we secured with Trans Mountain Pipeline. We also continue to use existing infrastructure, such as other pipelines and rail, to ship our growing production.

Another essential consideration as we grow is our environmental performance. Environment is a strategic business consideration at Cenovus, and we are implementing a progressive approach by integrating environmental performance into the business decisions we make. Protecting air quality, land and water will continue to be a critical part of that approach as we grow the company.

In order to continue to meet our commitments and execute on our 10-year plan, our people need the right tools and processes. I am pleased that we were able to implement our Cenovus Operations Management System in 2011. It will help us meet the high standards we have set for safety, environment and operating performance.

You can read more highlights from 2011 starting on page 32.

"Environment is a strategic business consideration at Cenovus, and we are implementing a progressive approach by integrating environmental performance into the business decisions we make."

2. Value creation: Achieving a material increase in shareholder value

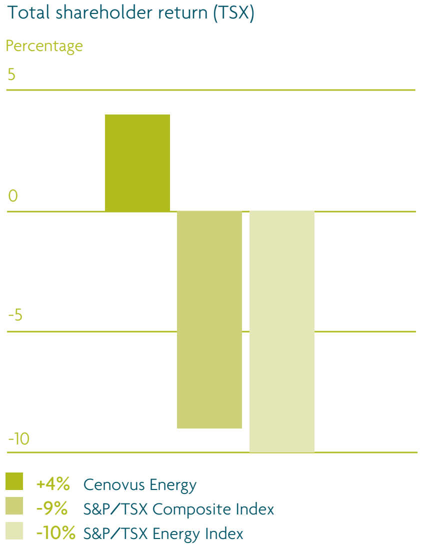
We plan to create value for our shareholders by growing our net asset value (NAV) and continuing to pay a strong and growing dividend over time. In addition to growing our dividend in 2012, we have made, and are continuing to make, significant strides towards our goal of doubling NAV between 2010 and 2015.

We want our employees to be able to measure their progress in increasing the value underlying each share. So, using the average of three independent external sources, we established a baseline illustrative NAV of $28 per share at December 2009. This number grew to $32 per share at year end 2010 and $37 per share at year end 2011 – a 32 percent increase from 2009.

We increased shareholder value in 2011 by advancing growth in our existing plays and identifying new opportunities from our resource base – all while continuing to be a low-cost operator. I'm pleased to report that in 2011 we again demonstrated strong total shareholder return – outperforming the S&P/TSX Energy Index and the S&P/TSX Composite Index by 14 percent and 13 percent respectively.

Cenovus shares outperformed the market in 2011

Total shareholder return (TSX)



"In addition to growing our dividend in 2012, we have made, and are continuing to make, significant strides towards our goal of doubling NAV between 2010 and 2015."

3. Innovation: Balancing our manufacturing approach with our need to innovate

One of the reasons we can successfully execute our projects relates to how we develop our oil sands assets – we balance a manufacturing approach with our need to continuously improve how we do things. The manufacturing approach we take in the design, construction and operation of our facilities gives us the ability to grow at a planned pace, allowing us to target bringing on one new phase of production about every 12 to 18 months. This manufacturing approach enables us to stay focused on safety, quality and cost, and complete projects on schedule.

However, we are also driven to innovate – to find ways to increase resource recovery while improving the way we produce oil and natural gas. That's why we continue to invest in technology development aimed at improving different aspects of our business, and it's why we are consciously building a strong culture of innovation at Cenovus. A highlight of the year for me, personally, was our hugely successful two-day summit dedicated to innovation and the sharing of ideas. The intent was to inspire and empower our people to rethink their work and adopt a solutions-oriented frame of mind. Throughout this report you will see a sampling of our innovations put into practice. For example, our Nisku yard in Alberta where we assemble entire modular units for shipment to Christina Lake and Foster Creek, and our patented blowdown boiler technology, commercialized in 2011, which increases the amount of steam we can create from the same barrel of water from about 80 percent to approximately 93 percent. Our innovations are focused on increasing our efficiencies, improving our environmental footprint and reducing our overall costs.

4. Reputation and communication: Living up to our commitments; telling our story

A company's reputation is one of its most important assets. Thanks to the dedication and actions of our people, I believe we have a reputation and a company to be proud of.

I am afforded many opportunities to talk about Cenovus, the tremendous resource base that is driving our oil growth strategy and our commitment to developing it responsibly. In 2011, we told our story in a number of ways: we released our first corporate responsibility report; we launched a new commercial, *A different oil sands*, which shows the drilling side of the oil sands; and we invited hundreds of people – politicians, media, investors and our own employees – to visit Christina Lake and Foster Creek to see our oil sands operations first-hand. Seeing really is believing. As I've said to a number of our guests, a picture's worth a thousand words, and a visit is worth a thousand pictures.

"A company's reputation is one of its most important assets. Thanks to the dedication and actions of our people, I believe we have a reputation and a company to be proud of."

We are, and have always been, focused on living up to our promises and on being a good neighbour. Our philosophy is to work with communities and stakeholders to build shared value. We want the communities where we live and work to be stronger and better off as a result of us being there.

"Our strategy maps out our future, but it's our people who will drive our success. It's our people who can make our company great."

5. Healthy organization: Ensuring Cenovus is a great place to work

A strong reputation helps attract talented people, which is especially important if you're hiring hundreds of employees, as we did in 2011. More than 700 people joining the company in a year is tremendous growth when you consider we started the year with 3,400 people. And, as we continue to grow, we'll need to hire even more.

That's why we're committed to building a healthy organization. One that fosters a positive, safe, vibrant workplace. One that inspires. And one that our employees enjoy coming to every day knowing their work matters and is contributing to the company's objectives and priorities.

Our strategy maps out our future, but it's our people who will drive our success. It's our people who can make our company great. That's why it is so important to me that our employees are happy to be at Cenovus and have a clear understanding of how they are adding value, every day. I am extremely pleased to report that the results of our first employee engagement survey conducted last year show that Cenovus is a place where people want to work. Our employees are energetic and enthusiastic. They are proud of their company and the work they do. They recognize the high expectations of Cenovus and they want to do more.

WHAT TO EXPECT IN 2012 – CONSISTENT, PREDICTABLE, RELIABLE PERFORMANCE

There is no question that our 10-year plan is ambitious, but I know we can achieve it. We are extremely well-positioned in terms of the quality of our resource, our portfolio of opportunities and our ability to deliver value.

In 2012 we plan to grow our oil production significantly. This production growth is expected to come as we ramp up production on existing phases, such as the Christina Lake phase C expansion, as well as from other projects as they progress. We plan to increase our total capital spending for 2012 by about 20 percent compared with 2011, with most of that investment being made on advancing existing and new oil sands projects, as well as on our Pelican Lake and conventional oil assets. We are increasing our investment in technology and each year expect to commercialize at least one of the more than 140 technology development projects we currently have underway. You can also expect to see continued workforce growth as we increase employee numbers in alignment with our 10-year business plan.

"We are extremely well-positioned in terms of the quality of our resource, our portfolio of opportunities and our ability to deliver value."

We've outlined our 2012 milestones so you can track our progress (see page 15).

With the outstanding work of our people over the past two years, we have already proven we can achieve great things in our industry. My sincere thanks to our Board of Directors, our Executive Team, and our employees and contractors for their contributions to our great results, and for having such passion and energy for Cenovus.

"You can expect us to deliver consistent, predictable, reliable performance year after year."

Certainly, we have accomplished a lot in our first two years as an independent company. We have established ourselves as a reliable company that's developed a predictable and transparent growth plan. We have continued to demonstrate measurable progress on the milestones we have set for ourselves and we are well on our way to achieving our goal of doubling net asset value by the end of 2015.

Yet, in many ways, we have only just begun. We have so many opportunities ahead of us. My promise to you is that we will stay focused on our 10-year plan: setting milestones, achieving excellent results and improving our environmental performance. You can expect us to deliver consistent, predictable, reliable performance year after year.

Our Executive Team and I look forward to our exciting future.

Brian C. Ferguson ● President & Chief Executive Officer

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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 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.

USING SPECIALIZED TECHNOLOGY *Pictured here is Foster Creek, our largest SAGD project, situated on the Cold Lake Air Weapons Range in northern Alberta.*

OUR OIL SANDS PROJECTS ARE

driving our growth

We currently have two producing SAGD projects in the oil sands – Foster Creek and Christina Lake – as well as several emerging projects, which are in various stages of development, and will play a significant part in our growth plan.

OUR OIL PRODUCTION IS EXPECTED TO INCREASE TO NEARLY HALF-A-MILLION BARRELS PER DAY NET BY THE END OF 2021.

FOSTER CREEK Our largest project, considered among the best commercial and technical SAGD projects in the industry

Location: About 330 km northeast of Edmonton

Reservoir depth: 450 m

Number of phases: eight so far (phases A, B, C, D & E are in operation; F, G & H are in early construction; application for future phases is expected to be submitted for regulatory review in 2013)

Producing wells: 204

Production: averaged approximately 110,000 barrels per day gross

Ultimate gross production capacity: between 290,000 and 310,000 barrels per day

Employees: about 585, including many local residents

CHRISTINA LAKE A top-tier reservoir with huge potential for growth

Location: about 120 km south of Fort McMurray

Reservoir depth: 375 m

Number of phases: seven so far (phases A, B & C are in operation; D & E are in construction; F & G are planned and have received regulatory approval; application for H is expected to be submitted for regulatory review in 2013)

Producing wells: 38

Production: averaged approximately 23,000 barrels per day gross

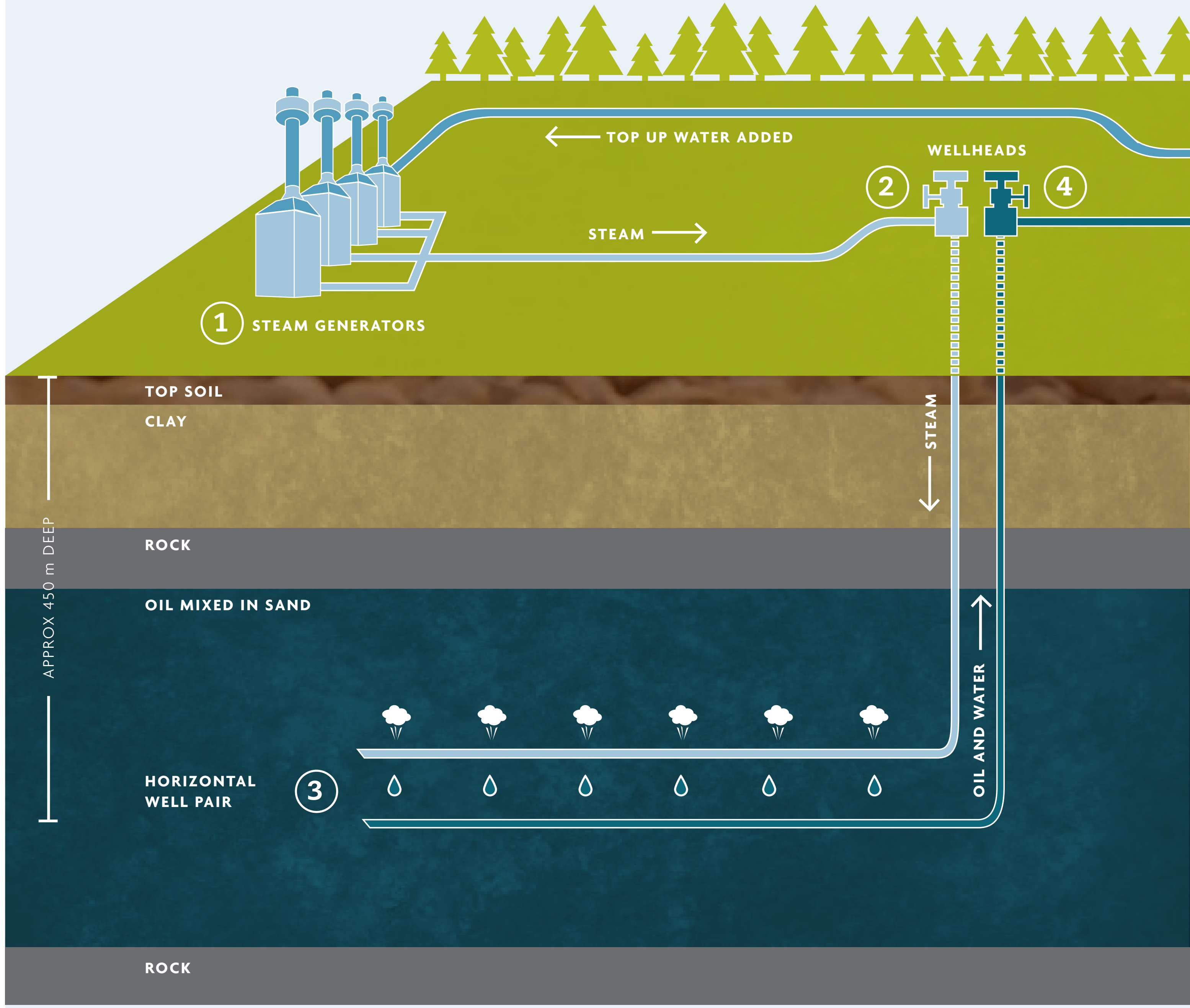
Ultimate gross production capacity: approximately 278,000 barrels per day

Employees: about 480

A WELL PAD AT CHRISTINA LAKE
To minimize the impact on the land, we drill several horizontal well pairs from a single compact area called a well pad. A typical well pad, which covers about 10 to 12 acres of surface land, can access about 185 acres of resource underground. We've successfully reduced the size of our well pads over time.

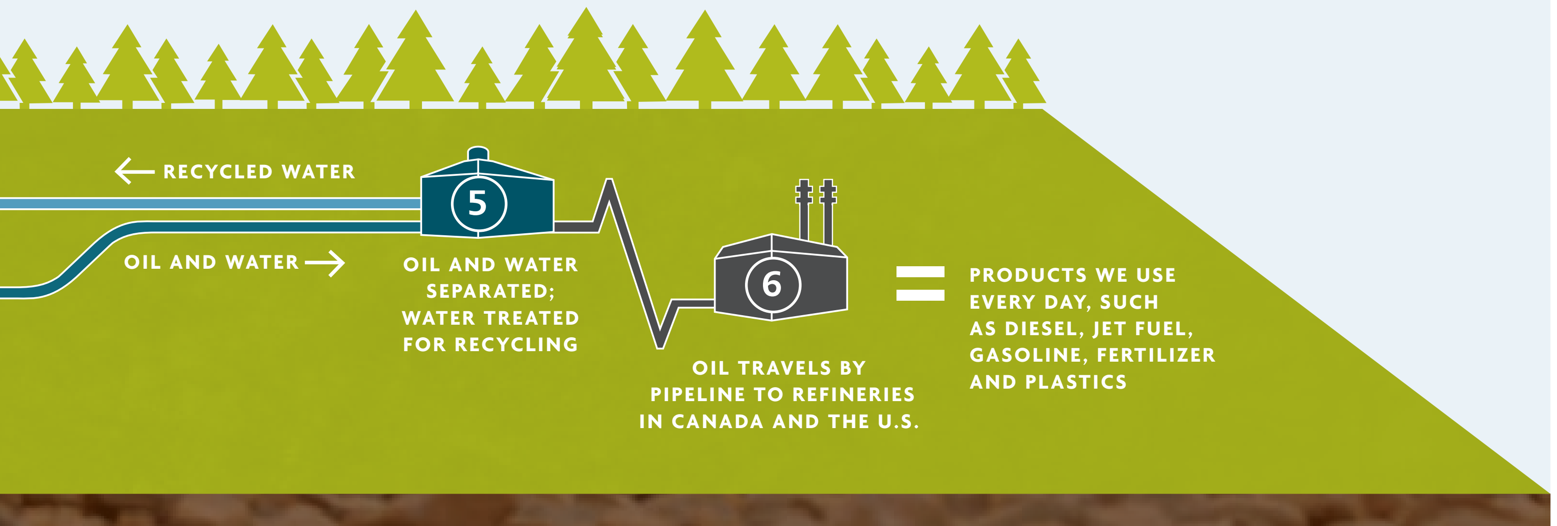
TECHNOLOGY

steam-assisted



IN ACTION

gravity drainage (SAGD)



1

STEAM IS GENERATED
Steam is used to soften the reservoir, so the oil can flow through the sand and be pumped to the surface. The steam is created in generators at our facilities and then transported by pipeline to the wellhead. The water used for steam is too salty to drink, as is most of the water used at our oil sands operations.

2

STEAM IS INJECTED UNDERGROUND
The steam is injected into the top well of a horizontal well pair to soften the oil.

3

OIL IS SOFTENED SO IT CAN FLOW
The softened oil, along with the water from the condensed steam, flows into the bottom well through slots in the pipe.

4

OIL AND WATER ARE BROUGHT TO SURFACE
The small slots in the pipe act as a filter, allowing the oil and water in while keeping the sand out. The oil and water are then brought to the surface.

5

OIL AND WATER ARE SEPARATED
The water is separated from the oil, treated and topped up with new water. Most of the water is returned to our steam generators where it's reused over and over again.

6

OIL IS TRANSPORTED TO BE REFINED
The oil is transported by pipeline to refineries in Canada and the U.S. The oil is turned into the many products we use and rely on every day.

USING LESS WATER AND USING IT

responsibly

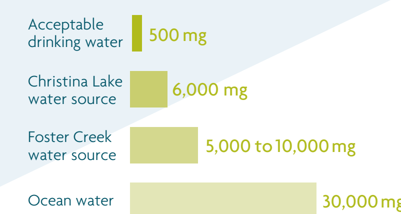
Water is an essential component of our operations. We're continually looking to implement new ways to reduce the amount of water we use to produce oil. None of the water we use to produce steam at our oil sands operations is fresh.

IMPROVING OUR STEAM GENERATION PROCESS BY USING BLOWDOWN BOILER TECHNOLOGY

Steam generators, pictured above, convert about 80 percent of one barrel of water to steam. To minimize waste, we've developed a process to re-boil the leftover water in a second generator to make additional steam. This re-boiling process, which is a Cenovus innovation, increases the amount of steam we can create from the same barrel of water from 80 percent to about 93 percent. We commercialized our blowdown boiler technology in 2011.

HOW SALTY IS THE WATER WE USE?
In our oil sands operations we primarily use saline water drawn from aquifers deep underground. Saline water is classified in Alberta as having more than 4,000 milligrams of salt per litre.

Saline water levels
Approximate milligrams of salt per litre
Graph not to scale.



STEAM TO OIL RATIO: A KEY MEASURE OF SAGD EFFICIENCY
Steam to oil ratio (SOR) is the amount of steam used to produce a barrel of oil. Cenovus has one of the lowest SORs in the industry. Our combined SOR for Foster Creek and Christina Lake in 2011 was about 2.2. A low SOR is a reflection of the quality of the reservoir and the approach used to develop the resource.

Using less steam means:

- Less water use
- Less natural gas used to create steam
- Lower emissions
- Smaller surface footprint
- Lower operating costs
- Lower capital costs

UNLOCKING VALUE THROUGH

SAGD technology

Unlike conventional oil, most of the oil in the oil sands doesn't flow naturally, so unconventional methods are used to access it. Canada is fortunate to have the oil sands, with enough oil to meet the country's current energy demand for generations.

There are two methods used to access the oil depending on how deep it is. If the oil is located close to the surface, it's mined. If it's deep underground, it's drilled and pumped to the surface using specialized technology like steam-assisted gravity drainage (SAGD). Projects that are drilled have a smaller surface land disturbance and don't require tailings ponds. All of Cenovus's projects are drilled.

ENHANCING VALUE THROUGH

leadership

Our Executive Team guides our plans, prioritizes our initiatives and leads by example. Underpinning their strong leadership is a tremendous depth of talent and knowledge that will enable us to execute on our 10-year business plan and continue to increase value for our shareholders.

"Our financial strategy supports the value pledge we've made to investors – to deliver on our commitments, build net asset value and generate sustainable growth for decades."

"I believe we've set a new standard for what SAGD projects are capable of achieving – and that's exciting."

Ivor Ruste ● Executive Vice-President & Chief Financial Officer

John Brannan ● Executive Vice-President & Chief Operating Officer

Cenovus plans to double net asset value by the end of 2015. Can you highlight what you achieved in 2011 to further that goal and how you're continuing to build shareholder value?

John Brannan All our teams have really built on our momentum from 2010. We've done a great job of setting targets and meeting our goals and objectives, including growing our oil production. For example, one of our key achievements was bringing on the phase C expansion at our Christina Lake project which grew our production capacity by 40,000 barrels per day gross at an industry-leading capital efficiency. I'm proud of the teams for not only bringing that expansion phase on safely but for bringing it on ahead of schedule and under budget. I believe we've set a new standard for what SAGD projects are capable of achieving – and that's exciting.

Don Swystun The successful start up of the coker at the CORE project at our Wood River Refinery is another great example of how we're building shareholder value. CORE was a major milestone for our company as well as a testament to the commitment and dedication of the Cenovus and ConocoPhillips staff working together. With solid planning, cost control and execution we were able to achieve best-in-class capital cost efficiency. The new four-drum coker allows us to upgrade more heavy oil feedstock into transportation fuels, increasing the overall profitability of the refinery and contributing to our net asset value.

Ivor Ruste Our many operational milestones also helped us achieve great financial results. We experienced strong margins, increased cash flow by 36 percent and strengthened our solid balance sheet. Our financial strategy supports the value pledge we've made to investors – to deliver on our commitments, build net asset value and generate sustainable growth for decades.

With all this growth, how is the company able to improve its performance?

John Brannan We have an overall philosophy of continuous improvement at Cenovus that keeps us focused on being better at what we do. Our manufacturing approach to developing our oil sands projects in manageable phases is a great example. Our teams are able to apply what they learn from one phase to the next, so over time we become even more efficient. These efficiencies help us keep our costs and our overall impact on the environment low. In 2011, we also focused on operational excellence by working smarter to optimize the capacity of the facilities we've installed. Overall, this has made us more cost-efficient. While we made some great strides as a company this past year, there's always room to improve. That's why I'm asking our operations teams to continue to focus on efficiencies in 2012.

Kerry Dyte Our focus on continuous improvement is evident across the company. Our employees look for ways to improve day by day – driving significant step changes that have a huge impact on our base business, and also implementing small incremental improvements where they can. It doesn't have to be a big idea to be a good idea – and that thinking has really inspired each and every one of us to look at how we do our jobs. No matter where we work, we can add to the company's value by improving a process, increasing our efficiency or driving down costs.

Hayward Walls To add to what Kerry said, we're consciously creating the kind of culture that fosters new ideas and new approaches. Having engaged employees is critical to our success and that's one reason we made a commitment to employee development. Employee development supports the career progression of our people in both our technical and managerial career streams. It leads to personal and business growth, and ensures our employees are challenged, have interesting work and are engaged – and that helps us to deliver on our commitments.

The oil sands industry continues to face public scrutiny around environmental issues. What is Cenovus doing to address this challenge?

Judy Fairburn In 2011, we continued to integrate long-term environmental planning into our business. In 2012, we'll be rolling out company-wide environmental commitments to further improve our environmental performance. We want to reinforce that everyone in the company has an accountability for the environment.

"One of the ways we've been able to distinguish ourselves in this industry is by innovating as we go, and when it comes to innovation I believe we're just getting started."

Harbir Chhina • Executive Vice-President, Oil Sands

"CORE was a major milestone for our company as well as a testament to the commitment and dedication of the Cenovus and ConocoPhillips staff working together."

Don Swystun • Executive Vice-President, Refining, Marketing, Transportation & Development

"We're proud of our business, and we take our job of developing the oil sands resource in a responsible manner seriously."

Sheila McIntosh • Executive Vice-President, Communications & Stakeholder Relations

Kerry Dyte We make sure that every day we're operating our business in a way we can be proud of. Like every industry, energy development has an impact on the environment, but we minimize that as much as we can.

John Brannan We're constantly striving to improve our performance, and one of our ongoing objectives is to advance technologies that increase oil production using the least amount of water, natural gas, electricity and land. We also want to make sure that people understand what we do, so we're actively telling our story.

Sheila McIntosh We use a variety of communication methods to help people understand our business better. Our aim is to showcase the drilling side of the oil sands, which isn't as well known. We're proud of our business, and we take our job of developing the oil sands resource in a responsible manner seriously. Our employees and contractors are great ambassadors for our company. Having more than 4,000 people telling our story is a powerful way to communicate. We encourage them to talk about the industry with their friends and family, share our story, show pictures of our operations, and be proud of the important work they're doing to develop energy resources responsibly.

You've talked about a number of ways Cenovus is working to improve. Can you explain how innovation and technology advancements play into that?

Harbir Chhina Innovation and technology advancements allow us to be a low-cost leader. One of the ways we've been able to distinguish ourselves in this industry is by innovating as we go, and when it comes to innovation I believe we're just getting started. One of our significant innovations so far is our Wedge Well™ technology, which allows us to produce 10 to 15 percent more oil with almost no additional steam required. Wedge Well™ technology improves our environmental performance and drives down our operating costs. In my experience, technology advancements are a competitive advantage in this industry and that's why we've made such a strong commitment to fund and support technology innovations.

Don Swystun Innovation really is the key to being better in this business. We've had some great successes already as a company, and that's exciting to be a part of. At this point, we have more than 140 technology development projects on the go, addressing all aspects of improving our business including construction, wellbore design, recovery schemes and drilling. About 75 percent of our technology developments will result in reductions in our environmental footprint. We've made great strides over the years, but we want to get better. I'm confident we'll get there with time, well-invested dollars and the bright people we have working at Cenovus.

Judy Fairburn I'd expand on Don's and Harbir's points to say innovation goes beyond technology. I believe innovation is about a mindset, approaching situations and problems in a different way. SAGD technology unlocked the resource potential of the oil sands more than a decade ago, and innovation will help us solve the environmental challenges we still face today. It's a fast-moving business and our strategy, our approach, our technology and our people – they all have to stay ahead of the curve to continue building value.

"Our people have a huge hand in building our reputation because they make Cenovus the company it is."

Hayward Walls ● Executive Vice-President, Organization & Workplace Development

"SAGD technology unlocked the resource potential of the oil sands more than a decade ago, and innovation will help us solve the environmental challenges we still face today."

Judy Fairburn ● Executive Vice-President, Environment & Strategic Planning

"Our employees look for ways to improve day by day – driving significant step changes that have a huge impact on our base business, but also implementing small incremental improvements where they can."

Kerry Dyte ● Executive Vice-President, General Counsel & Corporate Secretary

You achieved a number of significant operational milestones in 2011, in both the production and refining parts of the business. Can you talk about how the company is creating value from its portfolio of undeveloped assets?

Harbir Chhina We need to continue to build value by moving our resources along the value chain. The primary way we can do that is by drilling stratigraphic test wells. The data we get from these wells helps us to better define our resources and bring projects closer to approval and production, which inherently increases the value of those assets. The results from our stratigraphic drilling program contributed to an increase in our best estimate bitumen economic contingent resources to 8.2 billion barrels from 6.1 billion barrels and in our proved bitumen reserves to 1.5 billion barrels from 1.2 billion barrels. The results reinforced what we already knew – we're just getting started with this business and our future is rich with opportunity.

Ivor Ruste With such a rich portfolio of assets we won't be in a position to develop some of them for many years, so we're looking for other ways to bring the value forward. In 2011, we began discussions with interested parties looking to invest in our oil sands holdings. The asset we've identified to be part of this potential strategic transaction is the expanded Telephone Lake project, which is a huge untapped resource. We've had interest from around the globe in what we believe is a world-class opportunity. Talks are ongoing.

A strong reputation is an important asset for any company – what is Cenovus doing to build its reputation?

Sheila McIntosh A key way we're building our reputation is by meeting our commitments – ensuring we're walking the talk. It's critical we perform to the high standards we've set for ourselves and that we've encouraged our stakeholders to expect from us. For me, reputation is a critical measure of success, and it's something we work on every day. We're strengthening relationships. We're partnering with the communities where we live and work. We're focusing on good governance and transparency. We're living up to the commitments outlined in our Corporate Responsibility Policy. And we're talking to people about the good work we're doing. All these activities allow us to showcase our company and build our reputation.

Hayward Walls Our people have a huge hand in building our reputation because they make Cenovus the company it is. The passion they bring to sharing our story with family and friends is helping to build our reputation and makes people want to join our workforce. And that's great news. We will need a lot of people over the next decade to deliver on our growth plan, which is why we maintain a 10-year workforce plan to help ensure we have and continue to develop the organizational capacity we need to deliver on our commitments.

DRIVING VALUE BY

working together

Our teams work together to make smart decisions, advance technology and continuously improve. They inspire, share and learn from each other, and are the driving force behind our extraordinary achievements.

WORKING TOGETHER *Our teams are committed to embracing fresh thinking and new ideas. We leverage our more than 40 years of operating experience by working together to improve, solve problems and apply new thinking to our work in a practical, yet creative way.*

Oil Sands • Christina Lake, Facilities • Christina Lake, Geology and Geophysics • Christina Lake, Operations & Productions • Christina Lake, Project Development • Christina Lake, Reservoir Engineering • Greater Pelican Assets • Greater Pelican Assets, Operations, Pelican Lake • Land & FCCL Partnership • Narrows Lake • New Resource Plays, Business Ventures • New Resource Plays, Geoscience • New Resource Plays, NE Assets • New Resource Plays, New Ventures • New Resource Plays, Reservoir Engineering • New Resource Plays, SW Assets • New Resource Plays, Technical Analysis • Primrose Assets, Athabasca Gas • Primrose Assets, Facilities, Primrose • Primrose Assets, Geology & Geophysics • Primrose Assets, Infrastructure and Support Services • Primrose Assets, Operational Engineering • Primrose Assets, Primrose Operations • Primrose Assets, Reservoir Engineering • Technology Development • Refining, Marketing, Transportation & Development • Market & Business Development • Market Fundamentals & Hedging, Crude & Products • Market Fundamentals & Hedging, Data Management & Basis Analysis • Market Fundamentals & Hedging, Global & North American Gas • Marketing, Transportation & Power, Business Services • Marketing, Transportation & Power, Diluents Supply & Crude Oil Marketing • Marketing, Transportation & Power, Gas Marketing & Optimization • Marketing, Transportation & Power, Power • Marketing, Transportation & Power, Transportation & Business Development • Refining Business Unit • Oil & Natural Gas, Alberta, Brooks North • Oil & Natural Gas, Alberta, Drumheller • Oil & Natural Gas, Alberta, Land • Oil & Natural Gas, Alberta, Langevin • Oil & Natural Gas, Alberta, Production Operations • Oil & Natural Gas, Alberta, Suffield/Wainwright • Oil & Natural Gas Alberta, Technology, Enhanced Oil Recovery & Commercial Development • Oil & Natural Gas, Saskatchewan, Mineral/ Surface Land • Oil & Natural Gas, Saskatchewan, Operations, Saskatchewan • Oil & Natural Gas,

Saskatchewan, Shaunavon/Bakken • Oil & Natural Gas, Saskatchewan, Weyburn • Operations Support Teams • Environment Funds & Cenovus Operations Management System (COMS) Governance • Operations Health & Safety • Health & Safety, Oil Sands • Health & Safety, Oil & Natural Gas • Occupational Health • Operations Management System • Safety & Emergency Management • Operations Planning & Land • Operations Shared Services • Business Services, Energy Asset Management • Business Services, Engineering – Technical Services • Business Services, Facility Integrity – Technical Services • Business Services, Maintenance & Reliability – Technical Services • Drilling • Operations Training • Project Controls & Infrastructure • Supply Chain Management & Innovation & Continuous Improvement • Supply Chain Management & Innovation & Continuous Improvement, Drilling & Infrastructure • Supply Chain Management & Innovation & Continuous Improvement, Operations • Supply Chain Management & Innovation & Continuous Improvement, Projects • Supply Chain Management & Innovation & Continuous Improvement, Strategic Services • Regulatory, Local Community & Military • Local Community Relations • Military Liaison • Regulatory & Environmental Compliance • Regulatory & Environmental Applications • Transportation Regulatory Services • Communications & Stakeholder Relations • Communications, E-Communications & Library Services • Communications, External Communications & Brand Management • Communications, Internal Communications • Community Affairs • Government Affairs & Corporate Responsibility, Corporate Responsibility • Investor Relations, Business Intelligence • Media Relations • Environment & Strategic Planning • Environment Technology Investments • Environment Strategy & Policy • Strategic Environment Collaboration • Strategic Planning & Reserves Governance • Finance, Risk and A&D • Comptrollers, Budgets & Forecasts • Comptrollers, Conventional Oil & Natural Gas • Comptrollers, Finance Shared Services • Comptrollers, Oil Sands • Comptrollers, Refining, Marketing, Transportation & Development Accounting • Comptrollers, Reporting • Financial & Enterprise Risk, Risk Analytics • Financial & Enterprise Risk, Risk Compliance & Reporting • Sox Compliance • Tax • Treasury, Cash Management • Treasury, Treasury & Planning • Legal, Corporate Secretarial & Internal Audit • Internal Audit • Legal & Corporate Secretarial • Operations Legal • Organization & Workplace Development • Administrative Services, Administrative Services Field Solutions • Administrative Services, BOW Transition Logistics • Administrative Services, Building & Office Services • Administrative Services, Meetings & Events • Administrative Services, Real Estate Services • Executive Office Support • Governance, Compliance & Security, Cenovus Security • Governance, Compliance & Security, IT Security & Information Governance • Governance, Compliance & Security, Organization & Workplace Development Contracts & Business Office • HR Advisory • HR Development & Operations, HR Operations • HR Development & Operations, Organizational Development • HR Development & Operations, Workforce Practices & Central Advisory • Information Services, Architecture • Information Services, Business Office • Information Services, Corporate IT Solutions • Information Services, IT Technical Services • Information Services, Upstream IT Solutions • Leadership Strategy & Development

ADVANCING VALUE THROUGH

smart progress

We're proud of the progress we've made to date, which has led to tangible results – both in improving our operations and reducing our environmental impact. As a company we're passionate about finding new ways to keep getting better.

CONDUCTING VEGETATION ASSESSMENTS *As part of our reclamation planning, we conduct a vegetation assessment before operations begin like the one we conducted near our Weyburn operation, pictured here. The purpose of these assessments is to record the plant life growing in the area. The same assessment is done to track regrowth after operations are complete and reclamation is underway.*

HERE'S A SAMPLING OF THE IMPROVEMENTS WE'VE MADE OVER THE YEARS

PROGRESSING OUR ENVIRONMENTAL PERFORMANCE

We have a track record of developing solutions that make our environmental touch lighter

- Advanced or introduced technological improvements, such as electric submersible pumps, to our SAGD process. These various improvements have reduced our oil sands greenhouse gas emissions intensity by more than 25 percent over the last eight years and helped us maintain an industry-leading steam to oil ratio.
- Installed remote cameras at our Christina Lake and Foster Creek operations. These cameras allow us to better understand wildlife habitats to inform future developments at our field locations. With this information, we'll be able to focus reclamation in higher animal traffic areas and build awareness with staff working in the area.
- Moved natural gas wells underground to minimize land disturbance and military disruption on the Canadian Forces Base Suffield range in southern Alberta.

PUTTING NEW IDEAS TO WORK

We encourage innovative thinking that results in both incremental improvements and game changing solutions

- Built our own assembly yard in Nisku, Alberta, to construct modular units for our Christina Lake and Foster Creek facilities. The crews follow an integrated process to build the units on site and oversee production and shipping, which helps control costs, quality, schedule and helps improve safety.
- Improved planning and execution of our capital program has enabled us to increase the number of oil sands stratigraphic test wells we drill to 480 compared with 100 wells three years ago.
- Established long-term agreements with two Aboriginal communities. These agreements provide benefits such as employment, community investment, business development, education and training.
- Added positive observations of safe behaviour in our safety reporting to reinforce our culture of safety.

ENHANCING OIL RECOVERY

We look for ways to either improve existing technology or pursue new technology to access oil that's hard to recover using conventional methods

- Implemented our Wedge Well™ technology at Foster Creek and Christina Lake. We developed and patented this technology which, in addition to increasing total oil recovery, reduces the amount of steam we need. Using less steam means we're using less water and less natural gas.
- Completed a successful pilot project at our Christina Lake operation that tested the use of a solvent to improve the SAGD process. The project demonstrated increased oil production while using less water and natural gas.
- Improved oil rates and resource recovery per well at our Pelican Lake operation by using polymer flooding to access the oil.
- Extended the life of our oilfield in Weyburn, Saskatchewan, by injecting CO_2 into the reservoir. We expect to store more than 30 million tonnes of CO_2 underground over the life of the project.

GROWING VALUE BY

meeting our commitments

In 2011 we delivered great operational results and excellent financial performance, which contributed to our net asset value and share price performance. We met our commitments thanks to the energy, dedication and skill our employees bring to their jobs every day.

↗ UPDATED 10-YEAR BUSINESS STRATEGY

We built on our 2010 strategy, establishing new timelines and significant oil production increases for the next decade.

- Set an oil production goal of 500,000 barrels per day net by the end of 2021, of which 400,000 barrels per day net is from the oil sands
- Anticipate regulatory approval of 400,000 to 500,000 barrels per day net of oil sands projects by 2015

↗ STARTED UP COKER AT CORE PROJECT UPPER IMAGE

We own 50 percent of the Wood River Refinery in Illinois. The recent coker and refinery expansion increased Canadian heavy oil processing capacity and the amount of transportation fuels the refinery can produce.

↗ ACHIEVED EXCELLENT FINANCIAL RESULTS

We achieved our expectations for cash flow of $3.3 billion in 2011. The growth in cash flow compared to 2010 was largely driven by great operating results from our refining business, solid oil production and strong crude oil prices. Our refining business had an exceptional year thanks to improved refining margins, contributing $976 million to our operating cash flow. As a result of our strong performance, our balance sheet has strengthened as measured by our debt to capitalization ratio of 27 percent and our debt to adjusted EBITDA of 1.0 times, both of which remain at or below our long-term targeted ranges.

↗ GENERATED STRONG CASH FLOW FROM NATURAL GAS LOWER IMAGE

We have a large base of established, reliable natural gas properties in Alberta, including Drumheller, pictured right. We continued to generate strong free cash flow from our natural gas operations, which we manage as financial assets. These natural gas assets contributed approximately $660 million in operating cash flow in excess of the capital spent on them. These low-cost operations are critically important to the success of the company because of the cash flow they provide, which helps fund our oil growth.

↗ ADVANCED CHRISTINA LAKE OIL SANDS PROJECT IMAGE ON FACING PAGE

We build our oil sands projects in phases. Construction of phase D at Christina Lake is more than 70 percent complete and production is expected in the fourth quarter of 2012. Construction of phase E is more than 30 percent complete, with initial production anticipated in the fourth quarter of 2013.

134 MBBLS/D NET OF OIL AND NATURAL GAS LIQUIDS PRODUCED

17% INCREASE IN TOTAL PROVED RESERVES

34% INCREASE IN BEST ESTIMATE BITUMEN ECONOMIC CONTINGENT RESOURCES

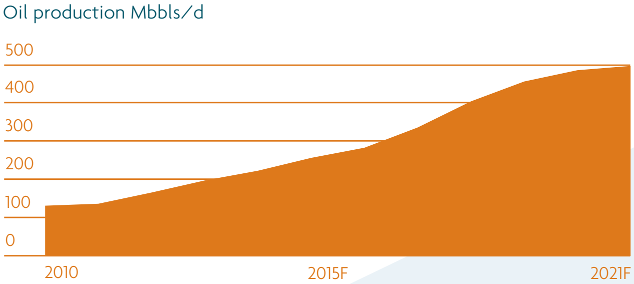
656 MMCF/D OF NATURAL GAS PRODUCED

7.4 MILLION NET ACRES OF LAND ACROSS ALBERTA AND SASKATCHEWAN

OUR OIL ASSETS

OIL IS OUR GROWTH DRIVER

Foster Creek and Christina Lake are our two producing oil sands projects. Grand Rapids is in the pilot project stage and Telephone Lake and Narrows Lake are both at an early stage of development. While the bulk of our future growth is anticipated to be in the oil sands, we also expect significant near-term growth in conventional oil production. Shaunavon and Bakken are early stage development opportunities that have huge potential and which we're growing rapidly. We've also successfully extended the life of our Weyburn project by at least 30 years thanks to the improvements we've made over time to enhance the oil recovery of the field.



Volumes are shown before royalties and net to Cenovus. 2012F based on midpoints of December 7, 2011 guidance document. 2013F through 2021F based on future price assumptions as noted in the Advisory. Forecast volumes are estimates only and subject to regulatory and partner approvals. See Advisory.

CELEBRATED FIRST OIL UPPER IMAGE
Our Christina Lake team celebrated first oil at phase C in August. Christina Lake is expected to reach a gross production capacity of 278,000 barrels per day by the end of 2019.

13% OIL SANDS PRODUCTION GROWTH

POSITIONED FOR GROWTH IN GREATER PELICAN REGION
In September, Pelican Lake reached a major milestone – achieving 100 million barrels of production since start up. We're undertaking a multi-year plan to increase drilling at Pelican Lake, with production expected to reach about 55,000 barrels per day by the end of 2016.

EXPANDED NISKU YARD CENTRE IMAGE
We expanded our module assembly yard in Nisku, Alberta, to better support construction activity at our oil sands projects. By increasing the site from 32 to 45 acres we doubled our construction capacity at the facility.

ABOUT $740 MILLION SPENT DOING BUSINESS WITH LOCAL AND ABORIGINAL COMPANIES IN OUR OPERATING COMMUNITIES

INVESTED IN EARLY-STAGE ENVIRONMENTAL TECHNOLOGIES
We invested about $6.5 million through our Environmental Opportunity Fund (EOF) in two innovative Canadian technology companies. General Fusion Inc. is developing nuclear fusion technology to generate cheap, safe and plentiful energy without greenhouse gas emissions, pollution or radioactive waste. Saltworks Technologies Inc. has developed a series of low cost, energy desalination technologies that can be powered by solar or waste heat. The EOF invests in third-party entrepreneurs developing early-stage technologies focused on renewable and alternative energy as well as environmentally-driven improvements for our oil and gas operations.

INCREASED PRODUCTION IN TIGHT OIL PLAY LOWER IMAGE
Tight oil is oil that's located in a reservoir with extremely low permeability – which means the oil is trapped in the reservoir. We more than doubled production at our Lower Shaunavon property to 2,000 barrels of oil per day. Our Bakken operation had average oil production of more than 1,500 barrels per day, including royalty interest volumes.

IMPROVED SAFETY PERFORMANCE UPPER IMAGE

Our Weyburn operation reached a major safety milestone – 20 years without an employee lost-time incident. Safety is a core value at Cenovus. Across the company our capital spending and operational activity increased, yet we continued to improve our safety performance.

RELEASED FIRST CORPORATE RESPONSIBILITY REPORT

Our first report, published in July, offers insights on how our company is living up to our Corporate Responsibility Policy and to the commitments we've made in key areas, including focusing on the health and safety of employees and the communities where we live and work; advancing environmental stewardship; ensuring good governance and transparency through reporting; engaging with stakeholders; and providing open and honest disclosure. The report provided a benchmark for us to document our achievements and identify ways to continually improve. We expect to release our 2011 report in mid-2012.

Recognized as a leader in sustainability

- 2011 Dow Jones Sustainability Index (DJSI) North America
- Carbon Disclosure Leadership Index (CDLI) for Canada for our leadership in emissions reporting

COMMERCIALIZED NEW TECHNOLOGY

We commercialized our blowdown boiler technology in 2011, which is used to create steam at our oil sands projects. Learn more about the technology (page 22/23 foldout).

CONFIRMED THAT CO_2 REMAINS UNDERGROUND AT WEYBURN OPERATION LOWER IMAGE

We commissioned a site assessment near our Weyburn operations to evaluate whether carbon dioxide (CO_2) in the soil and other reported concerns at a nearby property were a result of our enhanced oil recovery operations. Third-party research studies confirmed the CO_2 we inject at our Weyburn operation is not linked to CO_2 concentrations in the soil.

RESPONDED TO NATURAL DISASTERS

In late spring, communities close to our operations in Alberta and Saskatchewan were devastated by wildfires and flooding. The events impacted production at our Pelican Lake heavy oil operation in northern Alberta and at our conventional operations in southern Saskatchewan. In each instance, our employees worked diligently to safely and effectively bring operations back up. We also made a donation to the Canadian Red Cross and our staff volunteered with relief efforts in both provinces.

CONTRIBUTED TO DEVELOPMENT OF COSIA

We were a key participant in the development of Canada's Oil Sands Innovation Alliance (COSIA) – an innovative, environment-focused entity formed by producers of Canada's oil sands. Cenovus is committed to COSIA's vision to enable responsible and sustainable growth of Canada's oil sands while delivering accelerated improvement in environmental performance through collaborative action and innovation.

MADE A DIFFERENCE IN THE COMMUNITY

We contributed a total of $13 million to more than 800 organizations as part of our commitment to giving back as an Imagine Canada Caring Company. Our employees also contributed more than $1 million through our annual employee giving campaign, *Thanks & Giving*, which the company matched.

MET WITH STAKEHOLDERS UPPER IMAGE

160 MEETINGS AND OPEN HOUSES TO CONSULT WITH STAKEHOLDERS

CONDUCTED FIRST EMPLOYEE SURVEY

Our first survey showed employees are highly engaged and enabled to do their jobs well.

- 83% of employees provided feedback
- 94% of employees have an understanding of our strategy and goals
- 94% of employees believe we are committed to providing a safe and healthy work environment

INCREASED WORKFORCE TO SUPPORT GROWTH

We developed a 10-year workforce plan and added more than 700 people to ensure we have the right teams in place, in both our office and field locations, to execute on our growth plans.

HEARD FROM STAKEHOLDERS

As a follow-up to an extensive telephone survey we did in 2010, we conducted a shorter survey in 2011 to hear what people think about our business and operations, and the oil and gas industry in general. Those who were familiar with us generally had positive impressions of how we conduct our business, our safety practices, and our commitment to and involvement in the community. We plan to conduct a comprehensive survey every two years, and a shorter survey in alternate years.

RECEIVED SPECIAL THANK YOU LOWER IMAGE

We developed a new partnership with Ronald McDonald House and donated $1 million for initiatives in Edmonton, Calgary and Red Deer.

SHOWCASED OUR SITES UPPER IMAGE

We hosted dozens of tours to Foster Creek, Christina Lake and Weyburn for national and international media, government representatives, community stakeholders, members of the investment community and employees.

PROVIDED INTERACTIVE LEARNING OPPORTUNITIES CENTRE IMAGE

Employees learned about our operations and business strategy in a variety of ways including through company-wide forums and the use of interactive tools.

INCREASED AWARENESS OF CENOVUS

We met regularly with various stakeholders, reported on our performance and reached out to the broader public through advertising, and traditional and social media.

320 MEETINGS WITH SHAREHOLDERS AND THE INVESTMENT COMMUNITY IN CANADA, THE U.S. AND ACROSS EUROPE

1,000,000 HITS ON CENOVUS.COM

1,300 FOLLOWERS ON TWITTER

ASSESSED IMPACT OF OUR ADS

Our research showed that our advertising has been successful in increasing positive perception of the oil sands. Seventy-two percent of those surveyed, who remembered seeing at least two of our ads, had a more positive attitude about the oil sands.

PLANNED FOR FUTURE DEVELOPMENT LOWER IMAGE

A team of Cenovus staff and third-party environmental consultants visited Christina Lake to see how we're collecting baseline environmental data for regulatory applications and future project development. The data we collect on soil, vegetation, plants, trees, wildlife and water factors into how we design protective measures and future land reclamation plans.

PRESERVING VALUE BY

ensuring good governance

With years of business experience and a strong mix of skills, our Board of Directors oversees the management of our business, and is focused on preserving and increasing shareholder value.

To the shareholders:

For Cenovus, 2011 was all about building on a strong foundation to create value for shareholders. Value creation is an apt theme for Cenovus's second annual report. It captures the essence of what was planned, what was accomplished, what was delivered and what lies ahead. Cenovus's strategic goals lay out the plan in broad terms and the five key areas of focus, enumerated in Brian's letter, identify where the company is prioritizing its efforts. Strong results for 2011 demonstrate what was accomplished and provide a glimpse of what lies ahead. The year's total return to shareholders – well above the peer group average – quantifies what was delivered.

Your Board fully supports the company's strategy and is pleased the Executive Team has chosen value as their ultimate measure of success. We believe doing so will help them develop a better understanding of the type of opportunities where the company can add significant value and set appropriate priorities. It will help us assess their choices and judge the results.

Using value as a lens has already sharpened our focus on all elements of value creation including resources, reserves, production, transportation, refining and marketing. It is helping us gain a better understanding of the company's competitive strengths, clarify boundaries of its competitive advantage and evaluate trade-offs that need to be made. Additionally, a focus on value further illuminates the interplay between social responsibility, organizational structure, governance and compensation.

As you know from last year, Cenovus was launched with a solid foundation comprising high-quality physical assets and highly capable and experienced staff. Your Board believes that Cenovus's assets are somewhat unique and its strategy is particularly well-suited to its assets. This year's resources, reserves and production additions, and business execution, combined with its ability to generate cash, continue to demonstrate the company's potential. Cenovus's 2011 total shareholder return, which includes about $600 million in dividends and above peer average stock price performance in a tough market, demonstrates its ability to produce tangible value.

All in all, we believe that Cenovus is doing an excellent job of building on a solid foundation to convert the large potential of its assets into realizable value for you, the shareholder.

Respectfully submitted on behalf of the Board.

Michael A. Grandin • Board Chair

operating highlights

Before Royalties	2011	2010	% Change
Production			
Crude Oil and Natural Gas Liquids (bbls/d)			
Oil Sands – Heavy Oil			
Foster Creek	**54,868**	51,147	7
Christina Lake	**11,665**	7,898	48
Total	**66,533**	59,045	13
Pelican Lake	**20,424**	22,966	(11)
	86,957	82,011	6
Conventional Liquids			
Heavy Oil	**15,657**	16,659	(6)
Light and Medium Oil	**30,524**	29,346	4
Natural Gas Liquids	**1,101**	1,171	(6)
Total Crude Oil and Natural Gas Liquids (bbls/d)	**134,239**	129,187	4
Natural Gas (MMcf/d)	**656**	737	(11)
Refinery Operations (1)			
Crude Oil Capacity (Mbbls/d)	**452**	452	–
Crude Oil Runs (Mbbls/d)	**401**	386	4
Crude Utilization (%)	**89**	86	3
Proved Reserves (2)			
Total Reserves (MMBOE)	**1,945**	1,666	17
Year-end Bitumen Reserves (MMbbls)	**1,455**	1,154	26
Total Production Replacement (%)	**422**	398	6
Recycle Ratio (3)	**5.3**	7.8	(32)
Proved Finding and Development Costs ($/BOE) (4)	**5.95**	3.65	63
Reserve Life Index (years)	**22**	18	22

(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.

(3) For additional information regarding our Recycle Ratio, see our 2012 Management Proxy Circular, available at www.cenovus.com.

(4) Finding and Development Costs presented do not include changes in future development costs. For a description of the calculations used, refer to our Advisory. 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)	**2011**	2010	% Change
Revenues	**15,696**	12,641	24
Cash Flow [1]	**3,276**	2,412	36
Per Share – Diluted	**4.32**	3.20	
Operating Earnings [1]	**1,239**	799	55
Per Share – Diluted	**1.64**	1.06	
Net Earnings	**1,478**	1,081	37
Per Share – Diluted	**1.95**	1.43	
Capital Investment	**2,723**	2,115	29
Net Acquisition and Divestiture Activity	**(102)**	(221)	
Net Capital Investment	**2,621**	1,894	38
Dividends Per Common Share ($/share)	**0.80**	0.80	
Dividend Yield [2]	**2.36**	2.40	
Debt to Capitalization (%) [1]	**27**	29	
Debt to Adjusted EBITDA (times) [1]	**1.0**	1.3	

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

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

"The success we achieved in 2011 is a direct result of the consistent, predictable and reliable approach we take to growing value for our shareholders. Despite the challenging economic environment, our financial results were stronger in 2011 than the previous year and we grew our oil production as well as substantially added to our reserves and contingent resources, which contributed to an increased net asset value. We're well-positioned for another successful year in 2012."

Brian Ferguson ● President & Chief Executive Officer

Management's discussion and analysis

For the Year Ended December 31, 2011

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated February 15, 2012, should be read with our audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2011 ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory.

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

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated. Effective January 1, 2011, we adopted International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the 2011 and 2010 information has been prepared in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented in accordance with IFRS. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2011, we had a market capitalization of approximately $26 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. Our total 2011 average crude oil and NGLs production was in excess of 134,000 barrels per day and our average natural gas production was in excess of 650 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties, which we operate and have a 50 percent ownership interest in, are located in the Athabasca Region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca Region is our wholly owned Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta. In addition to our upstream assets, we have 50 percent ownership in two refineries located in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to mitigate the volatility associated with commodity price movements.

Our operational focus is to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Saskatchewan, and to continue the assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

Our strategy is to focus on the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic test wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects that we expect to develop in this area as well as our current ownership interests are as follows:

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

(1) Approximate ownership interest

In June 2010, we submitted a joint application and Environmental Impact Assessment ("EIA") for our Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day and be developed in up to three phases. Provided all regulatory requirements are met we anticipate receiving regulatory approval in the middle of 2012 with first production expected in 2016.

At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and EIA for a commercial SAGD operation. The proposed project is expected to have a gross production capacity of 180,000 barrels per day.

Our 100 percent owned Telephone Lake property is located within the Borealis Region and in December 2011, we submitted a revised joint application and EIA. The Telephone Lake project is now expected to have an initial gross production capacity of 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands and tight oil opportunities. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016, we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect 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 balance sheet capacity.

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful and growing dividends as part of delivering a strong total shareholder return over the long-term.

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.
- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains 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.

OVERVIEW OF 2011

In 2011, we achieved the milestones that we set for the year. We completed our planned capital programs, met or exceeded our production targets, kept our capital and operating costs in line with expectations and ended the year in a stronger financial position than we started. In the third quarter, phase C at Christina Lake achieved first production ahead of schedule and capital expenditures below budget for the entire phase. We have accelerated planned first production from phases D and E at Christina Lake to commence in the fourth quarters of 2012 and 2013, respectively each about six months earlier than originally expected. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design. Construction of the coker and start up activities of the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery were completed with total capital costs of US$3.8 billion (US$1.9 billion net to Cenovus), within 10 percent of its original budget. Demonstrating our strong resource base, our total bitumen, crude oil and NGLs proved reserves increased 22 percent to over 1.7 billion barrels and our best estimate bitumen economic contingent resources increased 34 percent to 8.2 billion barrels. Our operational performance in 2011 and consistent crude oil growth have increased our net asset value and we expect to reach our goal of doubling our December 2009 net asset value by the end of 2015.

OPERATIONAL RESULTS

Our average crude oil and NGLs production increased four percent to 134,239 barrels per day compared to 2010, primarily due to the start of production from phase C at Christina Lake in the third quarter of 2011, improved well performance and plant efficiency at Foster Creek as well as increased production from our Lower Shaunavon tight oil play. These production increases were partially offset by operational challenges including wet weather and flooding in southern Saskatchewan and Alberta and wild fires in northern Alberta which temporarily curtailed production at Pelican Lake. Our December 2011 average crude oil and NGLs production was 150,977 barrels per day, up 18 percent from the prior year.

At Christina Lake we received regulatory approval from the Alberta Energy Resources Conservation Board ("ERCB") for expansion phases E, F and G. This expansion approval, as well as the positive delineation results, added 270 million barrels of proved bitumen reserves.

Our best estimate bitumen economic contingent resources increased 2.1 billion barrels or approximately 34 percent from 2010. The substantial increase was primarily due to successful stratigraphic test well drilling, resulting in the conversion of prospective resources to contingent resources.

In the fourth quarter of 2011, we completed coker construction and start up activities of the CORE project at the Wood River Refinery. CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), 10 percent higher than originally budgeted. Structured test runs undertaken to date have been successful, and a five percent increase to clean product yield has been achieved. Testing will continue through the first quarter of 2012, and the Wood River Refinery's total heavy crude oil processing capacity is expected to increase to between 200,000 to 220,000 barrels per day, enhancing our ability to integrate our growing bitumen production.

Other significant 2011 operational results compared to 2010 include:

- Foster Creek production averaging 54,868 barrels per day, an increase of seven percent from 2010;
- Christina Lake production averaging 11,665 barrels per day, an increase of 48 percent from 2010 and ended 2011 producing approximately 23,000 barrels per day;
- Lower Shaunavon average production more than doubling to 2,041 barrels per day;
- Pelican Lake production averaging 20,424 barrels per day, a decrease of 11 percent partly due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Drilling 491 gross stratigraphic test wells, mainly in the first quarter, to support the next phases of expansion at Foster Creek and Christina Lake, gather data on the quality of our emerging projects and support regulatory applications;
- Commencing the regulatory approval process for two of our emerging projects with the filing of a regulatory application for a commercial SAGD operation at our Grand Rapids property with an expected gross production capacity of 180,000 barrels per day and filing a revised regulatory application for Telephone Lake with an expected initial gross production capacity of 90,000 barrels per day. With these applications filed we have 400,000 barrels per day of gross production capacity in the regulatory process;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G;
- Receiving approval from the Alberta Department of Energy ("ADOE") to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation;
- Receiving partner approval for expansion phases F, G and H at Foster Creek and expansion phase E at Christina Lake; and
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions. While year over year production was down, production throughout 2011 remained relatively flat with low levels of capital investment.

FINANCIAL RESULTS

Throughout 2011, our financial results benefited from higher crude oil prices and a significant increase in refining crack spreads when compared to 2010. As a result of the increased crack spreads, we saw substantially improved operating cash flow from our Refining and Marketing segment. The higher average crude oil prices improved operating cash flow from our crude oil and NGLs operations, although price had a negative impact on our royalty expense as the Canadian dollar WTI price is used to calculate the royalty rates at our Oil Sands operations.

The financial highlights for 2011 compared to 2010 include:

- Revenues increasing $3,055 million, or 24 percent, primarily due to increased crude oil and NGLs production, improved refined product prices, a 16 percent increase in the average sales price for crude oil and NGLs, excluding financial hedging, higher condensate prices and volumes used for blending partially offset by decreased natural gas volumes and average sales prices;
- Operating cash flow of $981 million from Refining and Marketing, an increase of $905 million, primarily due to higher refining margins that resulted from both higher refined product pricing and discounted crude oil feedstock costs;
- Cash flow of $3,276 million, increasing 36 percent, primarily due to the significant increase in operating cash flow from Refining and Marketing and improved crude oil and NGLs production and average sales price;
- Our Conventional natural gas operations generating $623 million of operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;

- Operating earnings increasing 55 percent or $440 million, primarily due to higher operating cash flow partially offset by increased general and administrative and income tax expenses (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Receiving approval from the ADOE to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation resulting in a one-time reduction in royalty expense of approximately $65 million; and
- Paying a quarterly dividend of $0.20 per share.

STRATEGIC PLAN UPDATE

In 2011, we provided an update to our 10 year strategic plan with a focus on doubling our net asset value between 2010 and 2015. To achieve this goal our 10 year strategic plan now targets:

- Expected gross production capacity at Foster Creek, including phases F, G and H as well as future phases, of between 290,000 to 310,000 barrels per day, an increase of 55,000 to 75,000 barrels per day from the original estimate;
- Accelerating the timelines for production at Foster Creek phases G and H by approximately one year, to 2015 and 2016 respectively, and for production at Christina Lake phases D and E by approximately six months with production now expected at phase D in the fourth quarter of 2012 and at phase E in the fourth quarter of 2013;
- Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016;
- Increasing Conventional crude oil production in Saskatchewan and southern Alberta to approximately 65,000 to 75,000 barrels per day by the end of 2016; and
- Assessing the potential of new oil projects on our existing properties and in new regions with a focus on light oil opportunities.

OUR BUSINESS ENVIRONMENT

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

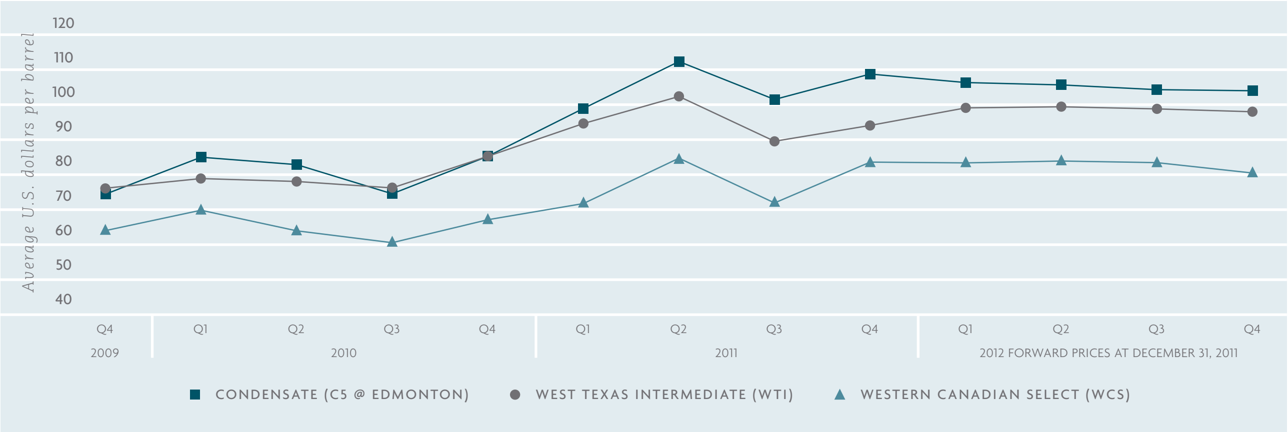
SELECTED BENCHMARK PRICES AND EXCHANGE RATES

	2011	**Q4**	**Q3**	**Q2**	**Q1**	2010	Q4	Q3	Q2	Q1	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	**95.11**	**94.06**	**89.54**	**102.34**	**94.60**	79.61	85.24	76.21	78.05	78.88	62.09
End of period	**98.83**	**98.83**	**79.20**	**95.42**	**106.72**	91.38	91.38	79.97	75.63	83.45	79.36
Western Canadian Select (WCS)											
Average	**77.96**	**83.58**	**71.92**	**84.70**	**71.74**	65.38	67.12	60.56	63.96	69.84	52.43
End of period	**84.37**	**84.37**	**69.38**	**75.32**	**91.37**	72.87	72.87	64.97	61.38	70.25	71.84
Average Differential WTI-WCS	**17.15**	**10.48**	**17.62**	**17.64**	**22.86**	14.23	18.12	15.65	14.09	9.04	9.66
Average Condensate (C5 @ Edmonton)	**105.34**	**108.74**	**101.48**	**112.33**	**98.90**	81.91	85.24	74.53	82.87	84.98	61.35
Average Differential WTI-Condensate (premium)/discount	**(10.23)**	**(14.68)**	**(11.94)**	**(9.99)**	**(4.30)**	(2.30)	–	1.68	(4.82)	(6.10)	0.74
Refining Margin 3-2-1 Average Crack Spreads *(US$/bbl)*											
Chicago	**24.55**	**19.23**	**33.35**	**29.00**	**16.62**	9.33	9.25	10.34	11.60	6.11	8.54
Midwest Combined (Group 3)	**25.26**	**20.75**	**34.04**	**27.19**	**19.04**	9.48	9.12	10.60	11.38	6.82	8.09
Natural Gas Average Prices											
AECO *($/GJ)*	**3.48**	**3.29**	**3.53**	**3.54**	**3.58**	3.91	3.39	3.52	3.66	5.08	3.92
NYMEX *(US$/MMBtu)*	**4.04**	**3.55**	**4.19**	**4.31**	**4.11**	4.39	3.80	4.38	4.09	5.30	3.99
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.31**	**0.17**	**0.34**	**0.42**	**0.29**	0.40	0.28	0.78	0.32	0.19	0.40
U.S./Canadian Dollar Exchange Rate											
Average	**1.012**	**0.978**	**1.020**	**1.033**	**1.015**	0.971	0.987	0.962	0.973	0.961	0.876

CRUDE OIL BENCHMARKS

WTI is an important benchmark for Canadian crude oil since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In 2011, the volatility in the price of WTI was mainly due to the economic conditions of the European Union and the Libyan geopolitical conflict. At their peak in April 2011, WTI prices rose to over US$110.00 per barrel, primarily due to the loss of Libyan supply to the global market. With the resolution of the Libyan conflict, production from the country resumed at the end of the third quarter and is expected to gradually increase in 2012. Concern over the economic health and solvency of several countries within the European Union as well as inland U.S. crude oil market congestion at the end of September dropped WTI to under US$80.00 per barrel, its lowest point in 2011. In the fourth quarter of 2011, WTI improved and ended the year at US$98.83 per barrel on optimism of a strengthening U.S. economy and the announcement of the Seaway Pipeline reversal which more than offset the continued economic concerns in the European Union and OPEC's announcement to increase its 2012 production ceiling. The 2011 average price of WTI also benefited from increased Asian demand, primarily from China.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In 2011, the average WTI-WCS differential was impacted by pipeline restrictions in the first quarter which widened the average differential to over US$22.00 per barrel. These pipeline restrictions were resolved and new delivery capacity to Cushing, Oklahoma was added in the second quarter which helped to narrow the average WTI-WCS differential to under US$18.00 per barrel for the second and third quarters. In the fourth quarter, the WTI-WCS differential further narrowed to under US$11.00 per barrel due to overall stronger refining industry utilizations and increased demand for heavy crude oil partly due to advanced purchases for the CORE project at our Wood River Refinery. When compared to 2010, the average WTI-WCS differential widened as increased production of Canadian heavy crude oil supply and pipeline outages were only partially offset by increased coking capacity and refining industry utilization.

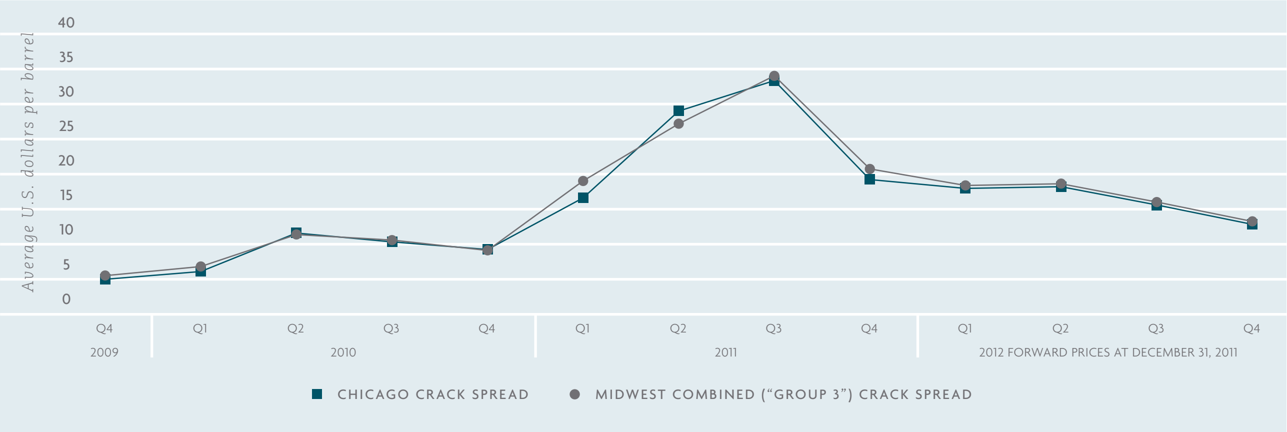


Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. Our blending ratios range from 10 percent to 30 percent. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the benchmark price 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. Throughout 2011, WTI discounts to offshore light crudes increased and condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland U.S. prices, and do not include an embedded inland U.S. discount included in the WTI benchmark price. However, in the fourth quarter of the 2011, the WTI discount to offshore light crude oils began to decrease with the announcement of the planned flow reversal of crude oil on the Seaway Pipeline in the middle of 2012. This planned flow reversal will supply crude oil to refineries on the U.S. Gulf Coast from the Cushing, Oklahoma hub. With the planned access to Gulf of Mexico markets, WTI prices strengthened in relation to offshore light oil benchmarks.

REFINING 3-2-1 CRACK SPREAD BENCHMARKS

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. Average crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices which increased substantially in 2011.

In the fourth quarter of 2011, crack spreads decreased compared to the previous quarter with the announcement that the flow of crude oil on the Seaway Pipeline will be reversed in the middle of 2012, increasing the price of crude oil feedstocks and narrowing the differential to global market prices. The Seaway Pipeline currently moves crude oil from the Gulf of Mexico to Cushing, Oklahoma. When reversed, it will help reduce surplus crude oil supply in the Cushing market by supplying heavy crude oil to the U.S. Gulf Coast refineries.



Benchmark crack spreads are a simplified view of the market based on last-in, first-out accounting, 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 purchased product costs based on first-in, first-out accounting.

OTHER BENCHMARKS

Natural gas prices remained low during 2011. The low prices reflect the continued strong growth in supply from liquids-rich natural gas basins and the slow response of demand to lower natural gas prices. We do not expect prices to improve significantly in 2012 as demand growth is not expected to respond quickly enough to absorb the current supply surplus.

During 2011, the Canadian dollar strengthened relative to the U.S. dollar. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative 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 strengthened Canadian dollar reduces our reported results, although a stronger Canadian dollar reduces our current period's refining capital investment.

FINANCIAL INFORMATION

In 2011 we began reporting our financial results in accordance with IFRS. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been re-presented in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the Consolidated Financial Statements.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009 (Prepared following previous GAAP)
Revenues [1]	**15,696**	**24%**	12,641	15%	11,031
Operating Cash Flow [2]	**3,862**	**30%**	2,981	-29%	4,189
Cash Flow [2]	**3,276**	**36%**	2,412	-15%	2,845
- per share – diluted [3]	**4.32**	**35%**	3.20	-16%	3.79
Operating Earnings [2]	**1,239**	**55%**	799	-48%	1,522
- per share – diluted [3]	**1.64**	**55%**	1.06	-48%	2.03
Net Earnings	**1,478**	**37%**	1,081	32%	818
- per share – basic [3]	**1.96**	**36%**	1.44	32%	1.09
- per share – diluted [3]	**1.95**	**36%**	1.43	31%	1.09
Total Assets	**22,194**	**12%**	19,840	-9%	21,755
Total Long-Term Debt	**3,527**	**3%**	3,432	-6%	3,656
Other Long-Term Obligations	**5,873**	**7%**	5,503	-15%	6,507
Capital Investment [4]	**2,723**	**29%**	2,115	-2%	2,162
Cash Dividends [5]	**603**		601		159
- per share [5]	**0.80**		0.80		US$0.20

[1] The 2009 revenue component of realized and unrealized financial hedging net gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

[2] Financial measure without standardized meaning as prescribed by IFRS ("non-GAAP") and defined within this MD&A.

[3] Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's ("Encana") common share balances based on the Arrangement which is further explained in the Advisory.

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

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

REVENUES VARIANCE

($ millions)	Years Ended December 31, **2011 vs 2010**	Years Ended December 31, 2010 vs 2009 [1]
Beginning period	$ 12,641	$ 11,031
Increase (decrease) due to:		
Oil Sands	584	428
Conventional	9	(110)
Refining and Marketing	2,397	1,306
Corporate and Eliminations	65	(14)
Ending period	**$ 15,696**	$ 12,641

[1] The 2009 revenue component of realized and unrealized financial hedging gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Oil Sands revenues for 2011 increased primarily due to higher average crude oil sales prices, increased crude oil production, as well as higher condensate prices.

Conventional revenues increased slightly in 2011 as higher average crude oil sales prices and light and medium crude oil production were almost completely offset by decreased natural gas average sales prices and expected declines in natural gas production.

Refining and Marketing revenues in 2011 increased primarily due to improved refined product prices and volumes as well as higher revenues related to operational third party sales undertaken by the marketing group.

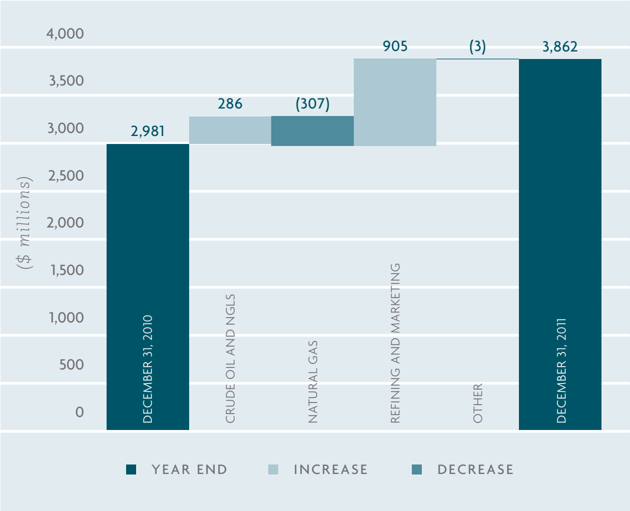
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Oil Sands			
Crude Oil and NGLs	**$ 1,210**	$ 1,047	$ 1,002
Natural Gas	**52**	77	181
Other	**6**	7	(2)
Conventional			
Crude Oil and NGLs	**881**	758	753
Natural Gas	**725**	1,007	1,880
Other	**7**	9	7
Refining and Marketing	**981**	76	368
Operating Cash Flow	**$ 3,862**	$ 2,981	$ 4,189

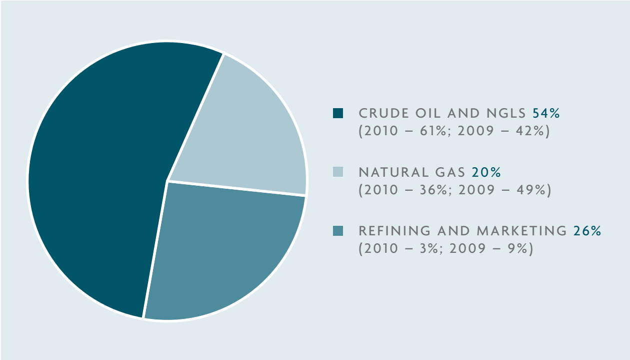
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation 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.

OPERATING CASH FLOW VARIANCE FOR THE YEAR ENDED DECEMBER 31, 2011 COMPARED TO DECEMBER 31, 2010



Overall, operating cash flow in 2011 increased $881 million primarily due to an increase of $905 million from Refining and Marketing as a result of improved refining margins. Operating cash flow from crude oil and NGLs increased $286 million due to an increase in average sales prices and sales volumes. The $307 million reduction from natural gas was due to decreased volumes, partly due to the divestiture of non-core natural gas properties at the end of the third quarter in 2010 and decreased average sales prices.

OPERATING CASH FLOW OF $3,862 MILLION FOR THE YEAR ENDED DECEMBER 31, 2011



The percentage of our operating cash flow generated from Refining and Marketing increased substantially in 2011 primarily due to improved refining margins. Crude oil and NGLs generated $2,091 million of operating cash flow in 2011 (2010 - $1,805 million; 2009 - $1,755 million), an increase of $286 million, from 2010. Despite this increase, the percentage of operating cash flow from crude oil and NGLs decreased to approximately 54 percent. The natural gas percentage of operating cash flow decreased from 2010 with the expected declines in our production and reduced sales prices.

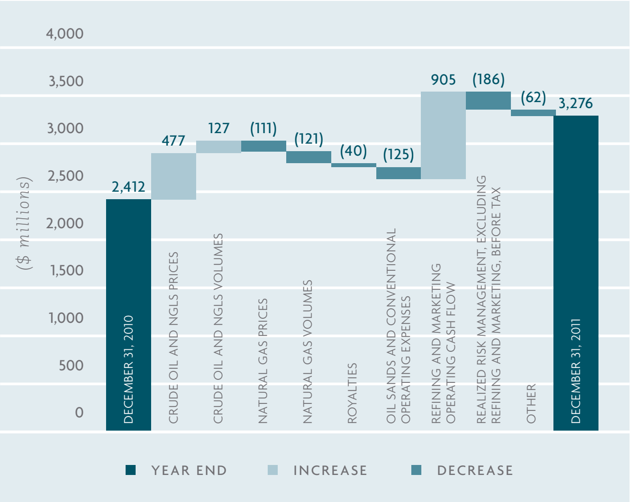
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Cash From Operating Activities	**$ 3,273**	$ 2,591	$ 3,039
(Add back) deduct:			
Net change in other assets and liabilities	**(82)**	(55)	(26)
Net change in non-cash working capital	**79**	234	220
Cash Flow	**$ 3,276**	$ 2,412	$ 2,845

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

CASH FLOW VARIANCE FOR THE YEAR ENDED DECEMBER 31, 2011 COMPARED TO DECEMBER 31, 2010



In 2011 our cash flow increased $864 million primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $905 million, mainly due to improved refining margins;
- A 16 percent increase in the average sales price of crude oil and NGLs to $72.84 per barrel;
- A four percent increase in our crude oil and NGLs sales volumes consistent with increased production primarily from Christina Lake, Foster Creek and conventional light and medium crude oil; and
- Lower interest expense with a stronger average Canadian dollar in 2011 decreasing interest on our U.S. dollar denominated long-term debt and partnership contribution payable as well as decreased interest on our partnership contribution payable as principal repayments are made quarterly.

The increases in our cash flow for 2011 were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $82 million compared to gains of $268 million in 2010;
- Increased operating expenses, primarily from crude oil and NGLs production, with additional personnel at Foster Creek, Christina Lake and Pelican Lake, increased repairs and maintenance and scheduled turnarounds activity, higher electricity costs and increased production from Bakken and Lower Shaunavon areas where production has been predominantly from single well batteries and resulted in increased trucking, fluid hauling and equipment rentals;
- Natural gas production declining 11 percent, as a result of the divestiture of non-core properties in 2010, lower capital investment and expected natural declines;
- An 11 percent decrease in the average natural gas sales price to $3.65 per Mcf;
- A $59 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- Realized foreign exchange losses of $68 million in 2011 compared to losses of $18 million in 2010 primarily on the quarterly settlements of the partnership contribution receivable; and
- An increase in royalties of $40 million primarily as a result of the higher Canadian dollar WTI prices used to calculate royalty rates and improved crude oil production partially offset by decreased natural gas production and receiving approval from the ADOE to include all previous capital investment for Foster Creek expansion phases F, G and H as part our existing Foster Creek royalty calculation resulting in a one-time reduction of approximately $65 million.

OPERATING EARNINGS

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Net Earnings	**$ 1,478**	$ 1,081	$ 818
(Add back) deduct:			
Unrealized risk management gains (losses), after-tax [(1)]	**134**	34	(494)
Non-operating foreign exchange gains (losses), after-tax [(2)]	**14**	153	(210)
Gain (loss) on divestiture of assets, after-tax	**91**	83	–
Gain on bargain purchase, after-tax	**–**	12	–
Operating Earnings	**$ 1,239**	$ 799	$ 1,522

(1) The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.

(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized 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. We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods.

The increase in operating earnings in 2011 is consistent with higher operating cash flow partially offset by higher general and administrative costs and income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

NET EARNINGS VARIANCE

($ millions)

Net Earnings for the Year Ended December 31, 2010	$ 1,081
Increase (decrease) due to:	
Operating Cash Flow	881
Corporate and Eliminations	
Unrealized risk management gains (losses), after-tax	100
Unrealized foreign exchange gains (losses)	(27)
Gain (loss) on divestiture of assets	(9)
Expenses [1]	(86)
Depreciation, depletion and amortization	7
Exploration expense	3
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(472)
Net Earnings for the Year Ended December 31, 2011	**$ 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.

In 2011, our net earnings increased $397 million compared to 2010. The factors discussed above that increased our operating cash flow in 2011 also increased our net earnings. Other significant factors that impacted our net earnings in 2011 include:

- Unrealized risk management gains, after-tax, of $134 million, compared to gains of $34 million in 2010;
- Unrealized foreign exchange gains of $42 million compared to gains of $69 million in 2010 consistent with the decrease of the Canadian dollar exchange rate at December 31, 2011 on the translation of our U.S. dollar long-term debt partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- An increase of $49 million for general and administrative expenses primarily due to increases in salaries and benefits and office support costs, as well as higher long-term incentive costs;
- Lower gains on the divestiture of assets, as we recognized gains of $107 million in 2011 compared to gains of $116 million in 2010 on the sale of non-core properties;
- A decrease of $7 million in Depletion, Depreciation and Amortization ("DD&A") expense as increased crude oil production and a $45 million impairment of a refining asset were partially offset by the addition of proved reserves at Foster Creek at the end of 2010 and decreased natural gas production; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $683 million, compared to $211 million in 2010.

NET CAPITAL INVESTMENT

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Oil Sands	**$ 1,415**	$ 857	$ 629
Conventional	**788**	526	466
Refining and Marketing	**393**	656	1,033
Corporate	**127**	76	34
Capital Investment	**2,723**	2,115	2,162
Acquisitions	**71**	86	3
Divestitures	**(173)**	(307)	(222)
Net Capital Investment [1]	**$ 2,621**	$ 1,894	$ 1,943

[1] Includes expenditures on PP&E and E&E. For purposes of managing our capital program, we do not differentiate between PP&E and E&E expenditures, and therefore we have not split our capital investment within this MD&A.

Oil Sands capital investment in 2011 included site construction, facility engineering and procurement spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment included site preparation and facility construction for expansion phases D, E and F and completion of phase C construction. Pelican Lake capital investment included infill drilling for polymer flooding and facility expansion and maintenance. We also drilled 480 gross stratigraphic test wells in 2011, of which 440 were drilled during the first quarter of 2011 which was our largest program to date. 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 2011 was primarily focused on the development of our crude oil properties including drilling, completion and facilities work in the Lower Shaunavon and Bakken areas. Our Conventional capital investment increased compared to 2010 and was on plan for 2011 despite flooding in the second quarter of 2011 in southern Saskatchewan which restricted access to our properties.

Refining and Marketing capital investment in 2011 was primarily focused on construction of the CORE project at the Wood River Refinery. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Corporate capital investment in 2011 was for tenant improvements and information technology costs.

ACQUISITIONS AND DIVESTITURES

The acquisitions in 2011 were primarily related to purchases of exploration and evaluation lands located contiguous to our existing core areas. Divestitures included the sale of marine terminal facilities in Kitimat, British Columbia and certain undeveloped land.

CAPITAL INVESTMENT DECISIONS

The table below reflects the outcome of our capital allocation process since the inception of Cenovus. It is important to understand that 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)	2011	2010	2009 (Prepared following previous GAAP)
Cash Flow	**$ 3,276**	$ 2,412	$ 2,845
Capital Investment (Committed and Growth)	**2,723**	2,115	2,162
Free Cash Flow [1]	**553**	297	683
Dividends paid [2]	**603**	601	159
	$ (50)	$ (304)	$ 524

[1] Free cash flow is a non-GAAP measure defined as cash flow less capital investment.

[2] The 2009 dividend represents the fourth quarter dividend determined in connection with the Arrangement based on carve-out earnings and cash flow.

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. This program increases cash flow certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

The realized risk management amounts in the tables below impact our operating cash flow, cash flow, operating earnings and net earnings. Unrealized risk management amounts are a non-cash item included in net earnings and affects the Corporate and Eliminations segment's financial results. Additional information regarding financial instruments can be found in the notes to the Consolidated Financial Statements.

FINANCIAL IMPACT OF RISK MANAGEMENT ACTIVITIES

	2011			2010			2009		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	**$ (135)**	**$ 106**	**$ (29)**	$ (17)	$ (92)	$ (109)	$ 49	$ (102)	$ (53)
Natural Gas	**210**	**38**	**248**	289	152	441	1,105	(566)	539
Refining	**(14)**	**7**	**(7)**	10	(8)	2	(34)	(10)	(44)
Power	**7**	**29**	**36**	(4)	(6)	(10)	(4)	(20)	(24)
Gains (Losses) on Risk Management	**68**	**180**	**248**	278	46	324	1,116	(698)	418
Income Tax Expense (Recovery)	**17**	**46**	**63**	79	12	91	312	(204)	108
Gains (Losses) on Risk Management, after-tax	**$ 51**	**$ 134**	**$ 185**	$ 199	$ 34	$ 233	$ 804	$ (494)	$ 310

In 2011, our risk management strategy resulted in realized losses on our crude oil financial instruments and realized gains on our natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and increased WTI benchmark crude oil prices which ended 2011 at a higher price than in 2010. We also recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices at the end of 2011 compared to our contract prices. Details of contract volumes and prices are found in the notes to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL AND NGLS PRODUCTION VOLUMES

(barrels per day)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009
Oil Sands					
Foster Creek	**54,868**	**7%**	51,147	36%	37,725
Christina Lake	**11,665**	**48%**	7,898	18%	6,698
Pelican Lake	**20,424**	**-11%**	22,966	-8%	24,870
Senlac	**–**	**–**	–	–	3,057
Conventional					
Heavy Oil	**15,657**	**-6%**	16,659	-7%	17,888
Light & Medium Oil	**30,524**	**4%**	29,346	-3%	30,394
NGLs [1]	**1,101**	**-6%**	1,171	-3%	1,206
	134,239	**4%**	129,187	6%	121,838

[1] NGLs include condensate volumes.

In 2011, our crude oil and NGLs production increased four percent primarily due to higher production at Christina Lake, Foster Creek and Conventional light and medium crude oil. These increases were partially offset by the temporary curtailment of production at Pelican Lake from wild fires which restricted pipeline transportation in the second quarter and the scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake. Conventional production was impacted by natural declines at our heavy oil operations, flooding and wet weather in southern Saskatchewan and Alberta in the second quarter, poor winter weather in the first quarter and the divestiture of non-core assets in the second quarter of 2010. Our average crude oil and NGLs production for December 2011 was 150,977 barrels per day, an increase of 22,971 barrels per day or 18 percent from December 2010 and was primarily due to increased production from Christina Lake and Conventional light and medium oil. Further information on the changes in our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009
Conventional	**619**	**-11%**	694	-11%	784
Oil Sands	**37**	**-14%**	43	-19%	53
	656	**-11%**	737	-12%	837

The decrease in our 2011 natural gas production compared to 2010 was due to our strategic decision to restrict capital spending on our natural gas assets over the prior two years in favour of increasing investment in crude oil projects. In 2010, we also divested of non-core natural gas properties which had produced approximately four percent of our 2010 production. Weather related issues, including extreme cold in the first quarter and wet weather in the second quarter of 2011, also reduced our natural gas production. While year over year natural gas production decreased, 2011 natural gas production remained consistent during the year despite low levels of capital investment. Further information on the changes in our natural gas production can be found in the Reportable Segments section of this MD&A.

OPERATING NETBACKS

	2011		2010		2009	
	Crude Oil & NGLs *($/bbl)*	**Natural Gas** *($/Mcf)*	Crude Oil & NGLs *($/bbl)*	Natural Gas *($/Mcf)*	Crude Oil & NGLs *($/bbl)*	Natural Gas *($/Mcf)*
					(Prepared following previous GAAP)	
Price [(1)]	**$ 72.84**	**$ 3.65**	$ 62.96	$ 4.09	$ 57.14	$ 4.15
Royalties	**9.84**	**0.06**	9.33	0.07	5.62	0.08
Transportation and blending [(1)]	**2.76**	**0.15**	1.88	0.17	1.60	0.15
Operating expenses	**13.47**	**1.10**	11.74	0.95	10.67	0.86
Production and mineral taxes	**0.56**	**0.04**	0.62	0.02	0.65	0.05
Netback excluding Realized Risk Management	**46.21**	**2.30**	39.39	2.88	38.60	3.01
Realized Risk Management Gains (Losses)	**(2.79)**	**0.87**	(0.36)	1.07	1.10	3.63
Netback including Realized Risk Management	**$ 43.42**	**$ 3.17**	$ 39.03	$ 3.95	$ 39.70	$ 6.64

(1) The crude oil and NGLs price and transportation and blending costs exclude $24.91 per barrel (2010 - $20.36 per barrel; 2009 - $14.55 per barrel) of condensate purchases which is blended with heavy crude oil.

In 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $6.82 per barrel primarily due to increased sales prices consistent with higher benchmark prices. Increased benchmark pricing also increased royalties. The increased sales prices were partially offset by higher operating expenses and transportation and blending costs. The increase in operating expenses was primarily due to higher staffing levels and increased repairs and maintenance activity at Foster Creek, Christina Lake and Pelican Lake. Transportation costs increased as a result of pursuing new markets for our increasing crude oil production.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $0.58 per Mcf primarily due to lower sales prices and increased operating expenses.

Further discussion on the items included in our operating netbacks is included 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.

REPORTABLE SEGMENTS

OIL SANDS

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

Significant factors that impacted our Oil Sands segment in 2011 include:

- A 270 million barrel increase in proved reserve volumes primarily due to receiving regulatory approval for Christina Lake phases E, F and G;
- Foster Creek adding 56 million barrels of proved reserves with the positive results from delineation drilling, improved recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Achieving first production at Christina Lake phase C in August ahead of schedule. Capital expenditures for the entire phase were below budget. Net production at Christina Lake was approximately 23,000 barrels per day at the end of the year;
- Implementing steam dilation as part of Christina Lake phase C start up which accelerated the initial start-up of production from well pairs;
- Foster Creek average production increasing seven percent to 54,868 barrels per day and Christina Lake production increasing 48 percent to an average of 11,665 barrels per day;
- Completing scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake on time and on budget;
- Receiving ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation resulting in a one-time reduction of about $65 million in our royalty expense;
- Receiving approval from the ERCB for Christina Lake expansion phases E, F and G;
- Receiving partner approval for Foster Creek expansion phases F, G and H and Christina Lake phase E;
- Successfully completing a large winter stratigraphic test well program with 480 gross wells drilled mainly in the first quarter to further progress our Oil Sands projects and address potential Pelican Lake lease expiries;
- Our best estimate bitumen contingent resources increasing by 2.1 billion barrels or approximately 34 percent primarily on transfers from prospective resources based on the results of our 2011 stratigraphic test well program;
- Pelican Lake production decreasing 11 percent to an average of 20,424 barrels per day, primarily due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G; and
- Updating our strategic plan which targets:
  - Increasing our expected total gross production capacity from Foster Creek phases F, G and H and future phases by 55,000 to 75,000 barrels per day from the original estimate;
  - Accelerating the timelines for first production at Foster Creek phases G and H by approximately one year;
  - Expected first production at Christina Lake phase D and phase E in the fourth quarters of 2012 and 2013 respectively, approximately six months earlier than initially planned. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design; and
  - Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016.

OIL SANDS – CRUDE OIL

FINANCIAL RESULTS

($ millions)	**2011**	2010	2009 [1] (Prepared following previous GAAP)
Gross Sales	**$ 3,217**	$ 2,610	$ 2,008
Less: Royalties	**282**	276	129
Revenues	**2,935**	2,334	1,879
Expenses			
Transportation and blending	**1,229**	934	626
Operating	**409**	339	297
Production and mineral tax	**–**	–	1
(Gains) losses on risk management	**87**	14	(47)
Operating Cash Flow	**1,210**	1,047	1,002
Capital Investment	**1,401**	850	629
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (191)**	$ 197	$ 373

[1] In 2009, realized financial hedging gains in revenue of $48 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

REVENUES VARIANCES

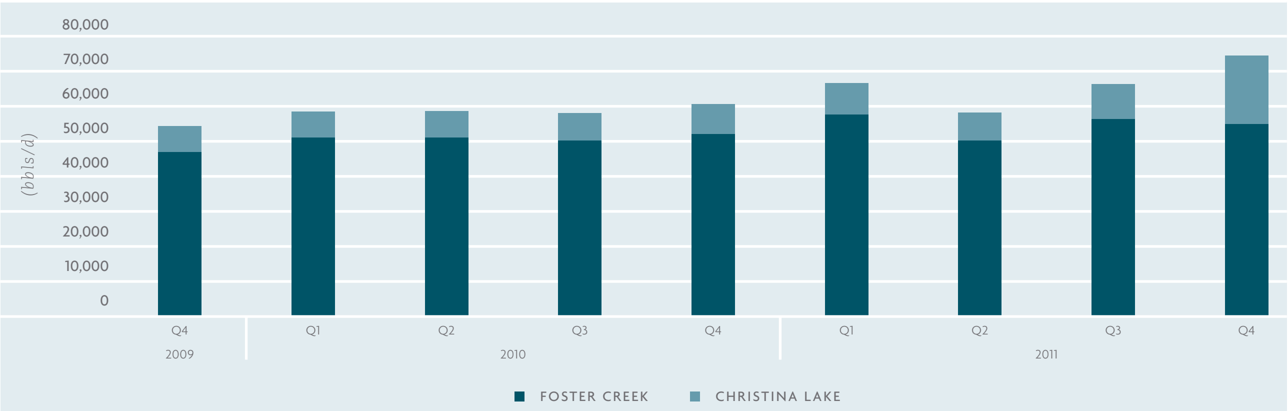
($ millions)	Year Ended December 31, 2010	Price	Volume	Royalties	Condensate [1]	**Year Ended December 31, 2011**
	$ 2,334	253	97	(6)	257	**$ 2,935**

[1] Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

PRODUCTION VOLUMES

Crude oil (barrels per day)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009
Foster Creek	**54,868**	**7%**	51,147	36%	37,725
Christina Lake	**11,665**	**48%**	7,898	18%	6,698
Subtotal	**66,533**	**13%**	59,045	33%	44,423
Pelican Lake	**20,424**	**-11%**	22,966	-8%	24,870
Senlac	**–**	**–**	–	–	3,057
	86,957	**6%**	82,011	13%	72,350

FOSTER CREEK AND CHRISTINA LAKE PRODUCTION VOLUMES BY QUARTER



In 2011, our average crude oil sales price increased 14 percent to $67.99 per barrel compared to 2010, consistent with the increase in the WCS benchmark price partially offset by higher condensate costs and the strengthening of the Canadian dollar.

Foster Creek production increased seven percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio, partially offset by the scheduled turnaround completed in the second quarter of 2011. The 48 percent increase in production at Christina Lake was the result of the start up of phase C in the third quarter of 2011, two well pairs which came on production in the fourth quarter of 2010 and four wells (which use our Wedge Well™ technology) which came on production in 2011, partially offset by a scheduled turnaround completed in the second quarter of 2011. The decline in our Pelican Lake production was primarily due to the temporary curtailment of production in the second quarter of 2011 due to wild fires in the area which decreased production by approximately 500 barrels per day for the year and a scheduled turnaround in the third quarter of 2011 which reduced production by approximately 300 barrels per day for the year. Production at Pelican Lake was also reduced by expected natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and price, volume, allowed operating and capital costs for post-payout projects (Foster Creek and Pelican Lake). Royalties increased $6 million in 2011 primarily due to increased production at Christina Lake and Foster Creek, higher Canadian dollar WTI prices and Foster Creek being in post–payout for a full year after achieving payout in the first quarter of 2010. Royalties would have been about $65 million higher had we not received ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation. Also partially offsetting these increases were higher capital investment and decreased production at Pelican Lake. The effective royalty rates for 2011 were 16.8 percent at Foster Creek (2010 – 16.2 percent; 2009 – 2.7 percent), 5.2 percent at Christina Lake (2010 – 3.9 percent; 2009 – 2.3 percent) and 11.5 percent at Pelican Lake (2010 – 21.1 percent; 2009 – 20.1 percent).

Transportation and blending costs increased $295 million in 2011. The condensate (blending) portion of the increase was $257 million and was the result of increases in the average cost of condensate and volumes required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $38 million primarily as a result of higher production volumes, increased transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions and additional transportation allowing us to access an offshore market in the fourth quarter.

Our 2011 operating costs were primarily for staffing, workovers, repairs and maintenance; Foster Creek and Christina Lake fuel costs; and chemical usage at Pelican Lake and Foster Creek. In total, operating costs increased $70 million in 2011 due to scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake, higher staffing levels, increased repairs and maintenance expense and higher long-term incentive expense, partially offset by decreased trucking and chemical costs.

Risk management activities resulted in realized losses of $87 million (2010 – losses of $14 million; 2009 – gains of $47 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of expected natural declines, our natural gas production decreased to 37 MMcf per day in 2011 (2010 – 43 MMcf per day; 2009 – 53 MMcf per day). As a result of the decreased production and lower natural gas prices, operating cash flow declined to $52 million for 2011 (2010 - $77 million; 2009 - $181 million).

OIL SANDS – CAPITAL INVESTMENT

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Foster Creek	**$ 429**	$ 277	$ 262
Christina Lake	**472**	346	224
Subtotal	**901**	623	486
Pelican Lake	**317**	104	72
New Resource Plays	**180**	113	17
Other [(1)]	**17**	17	54
Capital Investment [(2)]	**$ 1,415**	$ 857	$ 629

(1) Includes Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2011 was 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 and the drilling of stratigraphic test wells to support the development of our Oil Sands projects.

As compared to 2010, Foster Creek capital investment for 2011 increased primarily as a result of drilling 118 gross stratigraphic test wells in 2011 (2010 – 82 wells; 2009 – 65 wells) and higher spending on site construction, facility engineering and procurement for expansion phases F, G and H. Foster Creek capital investment also included maintenance capital on our producing phases and infrastructure spending.

Christina Lake capital investment was higher in 2011 compared to 2010 due primarily to the phase D, E and F expansions, including site preparation and facility construction, maintenance capital on producing phases and drilling 63 gross stratigraphic test wells (2010 – 24 wells; 2009 – 28 wells). We expect to increase gross production capacity to approximately 138,000 barrels per day with the completion of phases D and E. First production at phase D is expected in the fourth quarter of 2012 and first production at phase E is expected in the fourth quarter of 2013, both phases are now expected to commence production approximately six months earlier than initially scheduled. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design.

Pelican Lake capital investment for 2011 was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance capital. Facilities spending was focused on expanding fluid capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

(gross production wells drilled [(1)])	**2011**	2010	2009
Foster Creek	**21**	37	42
Christina Lake	**19**	32	–
Subtotal	**40**	69	42
Pelican Lake	**31**	12	5
Grand Rapids	**–**	1	–
Other	**3**	–	11
	74	82	58

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

Capital investment in new resource plays in 2011 was mainly related to the drilling of stratigraphic test wells, completion of seismic programs to support future oil sands projects and the Grand Rapids pilot project. First oil from the Grand Rapids pilot project was achieved in the third quarter of 2011. Results to date are as expected and will give us a better understanding of the performance of SAGD in the Grand Rapids formation.

STRATIGRAPHIC TEST WELLS

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the first quarter of 2011 and began our next stratigraphic test well drilling program in the fourth quarter. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, 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. We also drilled a number of wells at Pelican Lake to address potential lease expiries. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter.

Our 2011 stratigraphic test well program provided the primary basis for the 2.1 billion barrel increase to our best estimate bitumen contingent resources as results from the program caused prospective resources to be reclassified as contingent resources.

(gross stratigraphic test wells drilled)	**2011**	2010	2009
Foster Creek	**118**	82	65
Christina Lake	**63**	24	28
Subtotal	**181**	106	93
Pelican Lake	**57**	–	–
Narrows Lake	**47**	39	–
Grand Rapids	**59**	71	17
Telephone Lake	**40**	26	–
Borealis	**44**	–	–
Other	**52**	17	–
	480	259	110

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of 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 assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2011 include:

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $623 million;
- Average crude oil production from our Lower Shaunavon area more than doubling to 2,041 barrels per day with capital spending focusing on drilling, completions and facilities;
- Flooding which resulted in restricted access and shut-in production at our Bakken, Lower Shaunavon and Weyburn operations in the second quarter which reduced our production by approximately 1,400 barrels per day;
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions;
- Shifting our capital investment focus from natural gas to crude oil where we increased crude oil capital investment by 89 percent and drilled an additional 145 crude oil wells compared to 2010; and
- Updating our strategic plan which targets production of 65,000 to 75,000 barrels per day from our conventional crude oil operations in Saskatchewan and southern Alberta by the end of 2016 as well as assessing the potential of new crude oil projects on our existing properties and in new regions with a focus on tight oil opportunities.

CONVENTIONAL – CRUDE OIL AND NGLS

FINANCIAL RESULTS

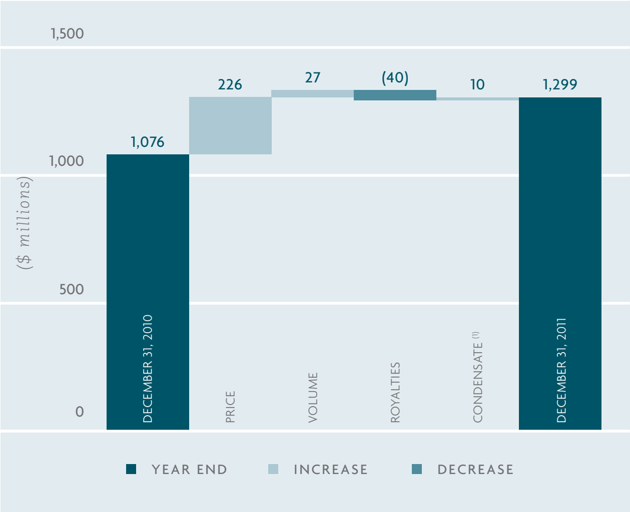
($ millions)	**2011**	2010	2009 [1] (Prepared following previous GAAP)
Gross Sales	**$ 1,492**	$ 1,229	$ 1,161
Less: Royalties	**193**	153	119
Revenues	**1,299**	1,076	1,042
Expenses			
Transportation and blending	**104**	86	87
Operating	**244**	199	172
Production and mineral taxes	**27**	28	28
(Gains) losses on risk management	**43**	5	2
Operating Cash Flow	**881**	758	753
Capital Investment	**686**	363	223
Operating Cash Flow in Excess of Related Capital Investment	**$ 195**	$ 395	$ 530

[1] In 2009, realized financial hedging losses in operating costs of $2 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

PRODUCTION VOLUMES

(barrels per day)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009
Heavy Oil					
Alberta	**15,657**	**-6%**	16,659	-7%	17,888
Light and Medium Oil					
Alberta	**10,763**	**-1%**	10,854	-9%	11,959
Saskatchewan	**19,761**	**7%**	18,492	-%	18,435
NGLs	**1,101**	**-6%**	1,171	-3%	1,206
	47,282	**-%**	47,176	-5%	49,488

REVENUES VARIANCE FOR THE YEARS ENDED DECEMBER 31, 2011 COMPARED TO DECEMBER 31, 2010



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

Our average crude oil and NGLs sales price increased 19 percent to $81.41 per barrel, consistent with the increase in crude oil benchmark prices.

Our sales and production volumes increased slightly, primarily because of higher light and medium crude oil production from our Bakken and Lower Shaunavon areas. These increases were mostly offset by the effects of cold weather in Alberta in early 2011, wet weather in Alberta and Saskatchewan in the middle of 2011, natural declines and the 2010 divestiture of non-core properties.

Royalties increased by $40 million primarily as a result of increased crude oil prices which resulted in an effective crude oil royalty rate of 14.2 percent (2010 – 13.3 percent; 2009 – 11.4 percent).

Transportation and blending costs increased $18 million. The condensate portion of the increase was $10 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending consistent with the decline in heavy oil production. Transportation costs increased $8 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls.

Our primary operating costs components were electricity, repairs and maintenance, workover activity and staff costs. Operating costs increased $45 million for 2011 primarily due to higher electricity costs, increased repairs and maintenance and workover activity, higher salaries and benefits, increased trucking and waste handling costs as well as increased equipment rentals.

Risk Management activities resulted in realized losses of $43 million (2010 – losses of $5 million; 2009 – losses of $2 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased $200 million in 2011 primarily due to a $323 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, partially offset by higher crude oil and NGLs prices and increased light and medium crude oil production.

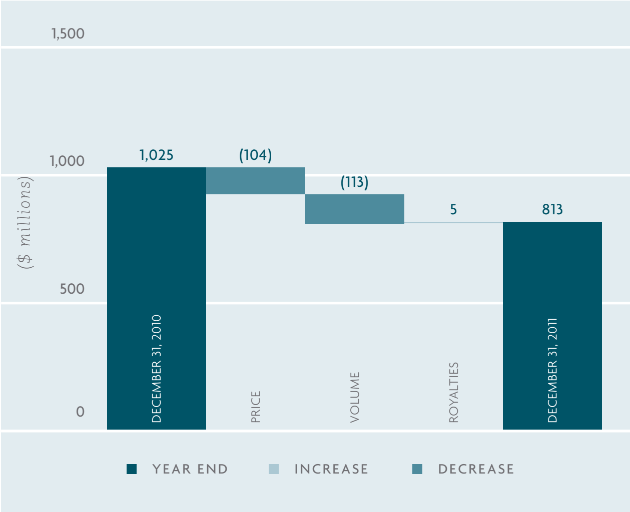
CONVENTIONAL – NATURAL GAS

FINANCIAL RESULTS

($ millions)	**2011**	2010	2009 (1) (Prepared following previous GAAP)
Gross Sales	**$ 825**	$ 1,042	$ 1,189
Less: Royalties	**12**	17	19
Revenues	**813**	1,025	1,170
Expenses			
Transportation and blending	**34**	44	45
Operating	**240**	231	236
Production and mineral taxes	**9**	6	15
(Gains) losses on risk management	**(195)**	(263)	(1,006)
Operating Cash Flow	**725**	1,007	1,880
Capital Investment	**102**	163	243
Operating Cash Flow in Excess of Related Capital Investment	**$ 623**	$ 844	$ 1,637

(1) In 2009, realized financial hedging gains in revenue of $1,007 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

REVENUES VARIANCE FOR THE YEARS ENDED DECEMBER 31, 2011 COMPARED TO DECEMBER 31, 2010



Our natural gas revenues and operating cash flow were lower in 2011 primarily due to lower production and average sales prices. The decline in our average sales price is consistent with the change in the benchmark AECO price. The cumulative impact of restricted natural gas capital spending over the last two years, the 2010 divestiture of non-core properties which had produced approximately four percent of our 2010 production, extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes to 619 MMcf per day for 2011 (2010 – 694 MMcf per day; 2009 – 784 MMcf per day). While year over year production was down, production within 2011 remained relatively flat with low levels of capital investment.

Royalties decreased $5 million in 2011 due to lower production and prices. The average 2011 royalty rate was 1.5 percent (2010 – 1.7 percent; 2009 – 1.6 percent).

Transportation costs decreased $10 million due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, staffing costs and electricity. Operating expenses increased $9 million in 2011 as higher expenses associated with electricity, increased workover activity and long-term incentives were partially offset by reduced operations due to divestitures in 2010 and lower production volumes.

Risk management activities resulted in realized gains in 2011 of $195 million (2010 – gains of $263 million; 2009 – gains of $1,006 million) consistent with our 2011 contract price exceeding the 2011 average benchmark price.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $221 million primarily due to lower production volumes and average sales prices decreasing operating cash flow partially offset by a $61 million reduction in capital investment.

CONVENTIONAL – CAPITAL INVESTMENT

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Crude Oil	**$ 686**	$ 363	$ 223
Natural Gas	**102**	163	243
Capital Investment [1]	**$ 788**	$ 526	$ 466

[1] Includes expenditures on PP&E and E&E assets.

Capital investment in our Conventional segment was focused on our crude oil development opportunities and high value natural gas opportunities such as CBM recompletions. Increased crude oil capital investment in Saskatchewan was focused on drilling and facility work at Weyburn and appraisal projects, drilling, completions and facilities work in the Lower Shaunavon and Bakken areas. Alberta crude oil capital investment was focused on drilling activities. Despite the impact of flooding in southern Saskatchewan in the second quarter we were able to complete our 2011 planned capital investment.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to Alberta coal bed methane development.

(net wells)	**2011**	2010	2009
Crude Oil	**325**	180	105
Natural Gas	**65**	495	502
Recompletions	**1,122**	1,194	855
Stratigraphic Test Wells	**11**	9	5

REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include 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.

Significant factors related to our Refining and Marketing segment in 2011 include:

- Increased operating cash flow of $905 million primarily due to improved refining margins, consistent with higher benchmark crack spreads, and higher refinery utilization;
- Completed coker construction and start up activities of the CORE project in the fourth quarter of 2011; and
- Our refineries operating at 89 percent of capacity producing 419 thousand barrels per day of refined products.

FINANCIAL RESULTS

($ millions)	**2011**	2010	2009 [1] (Prepared following previous GAAP)
Revenues	**$ 10,625**	$ 8,228	$ 6,922
Purchased product	**9,149**	7,674	5,986
Gross margin	**1,476**	554	936
Expenses			
Operating expenses	**481**	488	534
(Gain) loss on risk management	**14**	(10)	34
Operating Cash Flow	**981**	76	368
Capital Investment	**393**	656	1,033
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 588**	$ (580)	$ (665)

(1) In 2009, realized financial hedging losses in purchased product of $34 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The gross margin for Refining and Marketing increased $922 million for 2011 primarily due to the significant improvement in refined product prices which more than offset higher purchased product costs compared to 2010. Refined product prices continue to be tied to global market prices which increased substantially in 2011. Purchased product costs, which are accounted for on a first-in, first-out basis, reflected the benefit of discounted heavy crude oil as well as discounts to U.S. inland crude oil for much of 2011. Both the heavy and inland crude oil discounts that benefited our refining financial results throughout 2011, reduced substantially midway through the fourth quarter with the announced plan to increase the transportation of crude oil to the U.S. gulf coast reducing the surplus that had generated the discounts. The benefit to our refining results of discounted purchased product prices demonstrates the effectiveness of our objective to economically integrate our heavy oil production. Gross margins realized in 2011 also reflected the impact of higher utilization when compared to 2010.

Operating costs, consisting mainly of labour, maintenance, utilities and supplies, decreased by $7 million in 2011 primarily due to the impact of a stronger Canadian dollar and reduced scheduled turnarounds costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $905 million in 2011 primarily due to the higher refining gross margins. This contrasts with 2010 which was affected by weaker refined product prices, refinery optimization and scheduled turnarounds. Capital investment decreased by $263 million in 2011 as CORE project construction neared completion.

REFINERY OPERATIONS [1]

	2011	2010	2009
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**401**	386	394
Crude utilization *(percent)*	**89**	86	87
Refined products *(Mbbls/d)*	**419**	405	417

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

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 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. Refining capacity increases attributable to the CORE project at the Wood River Refinery, including expanded coking and heavy oil processing capacities will be reflected in 2012 operations as plant test runs proceed.

Crude utilization in 2011 improved as the 2010 utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and scheduled turnarounds.

REFINING AND MARKETING – CAPITAL INVESTMENT

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Wood River Refinery	**$ 346**	$ 568	$ 944
Borger Refinery	**45**	87	88
Marketing	**2**	1	1
Capital Investment	**$ 393**	$ 656	$ 1,033

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River Refinery. In 2011, of the $346 million capital expenditures at the Wood River Refinery, $243 million were related to the CORE project. In the fourth quarter of 2011 we completed the CORE project coker construction. Total CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), or about 10 percent higher than originally budgeted.

The balance of the 2011 capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CORPORATE AND ELIMINATIONS

FINANCIAL RESULTS

($ millions)	**2011**	2010	2009 [1] (Prepared following previous GAAP)
Revenues	**$ (59)**	$ (124)	$ (110)
Expenses ((add)/deduct)			
Purchased product	**(59)**	(123)	(110)
Operating	**(1)**	(3)	–
(Gains) losses on risk management	**(180)**	(46)	698
	$ 181	$ 48	$ 698

[1] The 2009 revenue and operating cost components of unrealized financial hedging losses, $668 million and $30 million respectively, have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. 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 long-term power purchase contracts.

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

($ millions)	2011	2010	2009 [1] (Prepared following previous GAAP)
General and administrative	**$ 295**	$ 246	$ 211
Finance costs	**447**	498	476
Interest income	**(124)**	(144)	(187)
Foreign exchange (gain) loss, net	**26**	(51)	304
(Gain) loss on divestiture of assets	**(107)**	(116)	(2)
Other (income) loss, net	**4**	(13)	–
	$ 541	$ 420	$ 802

[1] 2009 interest, net has been reclassified to interest income and finance costs and accretion of asset retirement obligations has been reclassified to finance costs to conform to the current year's IFRS presentation.

General and administrative expenses increased $49 million in 2011. Increased staffing levels in 2011 to support our growth resulted in higher salaries and benefits, higher long-term incentive expense and increased office support costs.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In 2011, our finance costs were $51 million lower than 2010 primarily as a result of a stronger average Canadian dollar in 2011 reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as principal payments are made quarterly. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for 2011 was 5.5 percent (2010 – 5.8 percent; 2009 – 5.5 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for 2011 decreased by $20 million from 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as the balance is being collected combined with a stronger average Canadian dollar.

In 2011, we reported net foreign exchange losses of $26 million (2010 - gains of $51 million; 2009 – losses of $304 million), which includes unrealized gains of $42 million (2010 – unrealized gains of $69 million; 2009 – unrealized losses of $327 million) and realized losses of $68 million (2010 – realized losses of $18 million; 2009 – realized gains of $23 million). The decrease of the Canadian dollar exchange rate at December 31, 2011 from 2010 led to unrealized losses on our U.S. dollar denominated long-term debt partially offset by net gains on our U.S. dollar denominated partnership contribution receivable.

A net gain of $107 million was recorded on the divestiture of assets in 2011 (2010 – $116 million; 2009 - $2 million) mainly due to the sale of marine terminal facilities as well as certain non-core assets.

DEPRECIATION, DEPLETION AND AMORTIZATION

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Oil Sands	**$ 347**	$ 375	
Conventional	**778**	799	
Upstream	**1,125**	1,174	$ 1,250
Refining and Marketing [1]	**130**	96	232
Corporate and Eliminations	**40**	32	45
	$ 1,295	$ 1,302	$ 1,527

[1] On the January 1, 2010 transition to IFRS we elected to measure the carrying value of our refineries at their then estimated fair value resulting in a permanent $2.6 billion reduction to their carrying value and decreasing DD&A expense in 2010 compared to 2009.

For 2011, Oil Sands DD&A decreased $28 million as higher sales volumes at Foster Creek and Christina Lake were offset by lower sales volumes at Pelican Lake and lower Oil Sands DD&A rates. The lower Oil Sands DD&A rates for 2011 were mostly due to the significant addition of proved reserves at Foster Creek at the end of 2010.

DD&A in the Conventional segment decreased $21 million in 2011 primarily due to the decrease in natural gas production volumes and the disposition of non-core assets.

Refining and Marketing DD&A increased $34 million of which $45 million was due to the impairment of a catalytic cracking unit at the Wood River Refinery which will not be used in future operations. Refining and Marketing DD&A in 2010 included a loss on impairment of a redundant processing unit at the Borger Refinery of $14 million. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX EXPENSE

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Current tax	**$ 154**	$ 82	$ 934
Deferred tax	**575**	141	(590)
	$ 729	$ 223	$ 344

When comparing 2011 to 2010, our current tax expense increased primarily due to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception.

When comparing 2011 to 2010, our deferred tax expense increased primarily due to increased income from our Refining and Marketing segment which attract income tax at the higher U.S. tax rates and higher unrealized risk management gains.

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

($ millions, except percent amounts)	**2011**	2010	2009 (Prepared following previous GAAP)
Earnings before income tax	**$ 2,207**	$ 1,304	$ 1,162
Canadian statutory rate	**26.7%**	28.2%	29.2%
Expected income tax	**589**	368	339
Effect of taxes resulting from:			
Foreign tax rate differential	**78**	(22)	3
Non-deductible stock-based compensation	**18**	34	–
Multi-jurisdictional financing	**(50)**	(93)	(134)
Foreign exchange gains (losses) not included in net earnings	**(9)**	28	58
Non-taxable capital (gains) losses	**(9)**	(13)	30
Capital loss	**26**	(107)	–
Adjustments arising from prior year tax filings	**31**	26	(16)
Other	**55**	2	64
	729	223	344
Effective tax rate	**33.0%**	17.1%	29.6%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

The increase in our effective tax rate in 2011 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 and lower benefits of multi-jurisdictional financing. The effective tax rate for 2010 was unusually low because of a tax benefit recorded in respect of losses incurred in the U.S. in 2010.

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

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

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 INFORMATION

($ millions, except per share amounts)	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009 (Prepared following previous GAAP)
Production Volumes									
Crude Oil and NGLs	**144,273**	**133,496**	**121,762**	**137,355**	129,593	128,067	128,566	130,549	129,315
Natural Gas	**660**	**656**	**654**	**652**	688	738	751	775	797
Revenues (1)	**4,329**	**3,858**	**4,009**	**3,500**	3,363	2,962	3,094	3,222	2,970
Operating Cash Flow (2)	**1,019**	**945**	**1,064**	**834**	815	661	665	840	954
Cash Flow (2)	**851**	**793**	**939**	**693**	645	509	537	721	235
- per share – diluted (3)	**1.12**	**1.05**	**1.24**	**0.91**	0.85	0.68	0.71	0.96	0.31
Operating Earnings (2)	**332**	**303**	**395**	**209**	147	156	143	353	169
- per share – diluted (3)	**0.44**	**0.40**	**0.52**	**0.28**	0.19	0.21	0.19	0.47	0.23
Net Earnings	**266**	**510**	**655**	**47**	78	295	183	525	42
- per share – basic (3)	**0.35**	**0.68**	**0.87**	**0.06**	0.10	0.39	0.24	0.70	0.06
- per share – diluted (3)	**0.35**	**0.67**	**0.86**	**0.06**	0.10	0.39	0.24	0.70	0.06
Capital Investment (4)	**903**	**631**	**476**	**713**	701	479	444	491	507
Cash Dividends (5)	**151**	**150**	**151**	**151**	151	150	150	150	159
- per share (5)	**0.20**	**0.20**	**0.20**	**0.20**	0.20	0.20	0.20	0.20	US$0.20

(1) In the fourth quarter of 2009, realized and unrealized financial hedging gains from revenue of $35 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

(2) Non-GAAP measures defined within this MD&A.

(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the Arrangement which is further explained in the Advisory.

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

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

The improvements in our operational and financial results in the fourth quarter of 2011 demonstrated the dedication of our teams throughout the year. In the fourth quarter, we completed the coker construction and start up activities of the CORE project construction at the Wood River Refinery, more than doubled production from Christina Lake and Lower Shaunavon compared to the fourth quarter of 2010 and completed our 2011 capital program despite the impacts of wet weather in the second and third quarters.

In the fourth quarter of 2011, coker construction and start up activities of the CORE project at the Wood River Refinery were completed. The initial CORE design included increasing nameplate refining capacity by 50,000 barrels per day and doubling heavy crude oil refining capacity to approximately 240,000 barrels per day, enhancing our ability to integrate our growing bitumen production. Total CORE project construction costs are within 10 percent of its original budget.

Our crude oil and NGLs fourth quarter production increased by 11 percent compared to the same period in 2010 due to increased production from Christina Lake, Foster Creek and at our Conventional light and medium crude oil properties. Partially offsetting these increases was the expected natural declines at Pelican Lake and at our Conventional heavy oil properties. The increase in production at Christina Lake was mainly due to the start of production at phase C in the third quarter of 2011.

We applied for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities to Christina Lake, increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G.

Natural gas production in the fourth quarter of 2011 was 660 MMcf per day, a decrease of four percent from 2010 due to expected declines in production from limited capital investment.

Capital investment in the fourth quarter of 2011 was $903 million, an increase of $202 million from 2010. The fourth quarter was extremely busy with activity at three phases at Foster Creek, three phases at Christina Lake and our drilling and completions programs across the other areas.

Operating cash flow increased $204 million in the fourth quarter of 2011 primarily due to crude oil and NGLs increasing $157 million due to higher average sales prices and sales volumes. Refining and Marketing operating cash flow increased $113 million attributable to improved refining margins. The $64 million decrease in operating cash flow from natural gas was consistent with lower production volumes and average sales prices.

In the fourth quarter of 2011 our cash flow increased $206 million compared to 2010 primarily due to:

- A 28 percent increase in the average sales price of crude oil and NGLs to $80.50 per barrel;
- An increase in operating cash flow from Refining and Marketing of $113 million, mainly due to improved refining margins; and
- An increase in our crude oil and NGLs sales volumes consistent with the 11 percent increase in production volumes primarily related to Christina Lake, conventional light and medium crude oil and Foster Creek.

The increases in our cash flow in the fourth quarter of 2011 were partially offset by:

- Increased operating expenses, primarily from crude oil and NGLs production, due to higher staffing levels at Foster Creek, Christina Lake and Pelican Lake, increased trucking and fluid hauling costs with increased production at Bakken and Lower Shaunavon and higher electricity and workover costs;
- Realized risk management gains before tax, excluding Refining and Marketing, of $29 million compared to gains of $79 million in 2010;
- An increase in royalties of $43 million mainly as a result of higher crude oil production and increases to the Canadian dollar equivalent WTI price used to calculate certain royalty rates;
- A $29 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- A six percent decrease in the average natural gas sales price to $3.35 per Mcf; and
- Natural gas production declining four percent (28 MMcf per day), as a result of lower capital investment and expected natural declines.

In the fourth quarter of 2011, our net earnings increased $188 million compared to 2010. The factors discussed above that increased our operating cash flow in the fourth quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 fourth quarter net earnings include:

- Unrealized risk management losses, after-tax, of $180 million, compared to losses of $197 million in the fourth quarter of 2010;
- A gain of $104 million on the divesture of a non-core asset in the fourth quarter of 2011 compared to the fourth quarter of 2010 when we recognized a loss of $3 million;
- Increased DD&A expense of $59 million primarily due to a $45 million refining asset impairment in the fourth quarter of 2011; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, of $150 million, compared to $75 million in 2010.

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 contingent and prospective bitumen resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets 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 2011 include:

- Bitumen proved reserves increased approximately 26 percent and proved plus probable reserves increased approximately 16 percent;
  - Christina Lake added proved reserves of 270 million barrels while proved plus probable reserves increased by 213 million barrels. Increases at Christina Lake were primarily a result of receiving regulatory approval to expand the development area and from positive delineation results;
  - Foster Creek added proved reserves of 56 million barrels and proved plus probable reserves of 79 million barrels. Increases at Foster Creek were primarily due to positive revisions from delineation results, increased recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Heavy oil proved reserves increased approximately four percent and proved plus probable reserves increased approximately seven percent. These increases were primarily as a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium oil and NGLs proved and proved plus probable reserves each increased by approximately four percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and the successful performance of those flood areas at Weyburn;
- Natural gas proved reserves declined approximately 13 percent and proved plus probable reserves declined approximately 11 percent due to extensions and technical revisions not offsetting production and due to the impacts of declined capital investment;
- Best estimate economic contingent resources increased 2.1 billion barrels or approximately 34 percent. This increase is primarily as a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources and positive technical revisions to volumetric and recovery factor estimates;
- Best estimate prospective resources declined 2.3 billion barrels or approximately 19 percent, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling.

The reserves and resources data is presented as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs and as at December 31, 2010 using McDaniel's January 1, 2011 forecast prices and costs. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalty volumes presented below do not include reserves associated with this production.

RESERVES AT DECEMBER 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Proved	**1,455**	1,154	**175**	169	**115**	111	**1,203**	1,390
Probable	**490**	523	**109**	97	**51**	49	**391**	410
Proved plus Probable	**1,945**	1,677	**284**	266	**166**	160	**1,594**	1,800

RECONCILIATION OF PROVED RESERVES

Before Royalties	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2010	1,154	169	111	1,390
Extensions and Improved Recovery	256	16	13	50
Discoveries	–	–	–	–
Technical Revisions	69	2	1	29
Economic Factors	–	1	–	(28)
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Production	(24)	(13)	(10)	(238)
December 31, 2011	1,455	175	115	1,203
Year over year change	301	6	4	(187)
	26%	4%	4%	-13%

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2010	523	97	49	410
Extensions and Improved Recovery	32	14	3	11
Discoveries	–	–	–	–
Technical Revisions	(65)	(2)	(1)	(27)
Economic Factors	–	–	–	(3)
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Production	–	–	–	–
December 31, 2011	490	109	51	391
Year over year change	(33)	12	2	(19)
	-6%	12%	4%	-5%

ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES AT DECEMBER 31

	Bitumen *(billions of barrels)*	
Before Royalties	**2011**	2010
Economic contingent resources [1]		
Low Estimate	**6.0**	4.4
Best Estimate	**8.2**	6.1
High Estimate	**10.8**	8.0
Prospective resources [1][2]		
Low Estimate	**5.7**	7.3
Best Estimate	**10.0**	12.3
High Estimate	**17.9**	21.7

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

(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. The contingencies applicable to our contingent resources are not categorized as economic. 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 for expansion of the Christina Lake development area resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic test well program in the Borealis and Pelican Lake Regions 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.

Bitumen reserves and resources increased in part because of improvements in SAGD performance at our Foster Creek and Christina Lake properties resulting from improved operating performance and the use of wells drilled using our Wedge Well™ technology. 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 Annual Information Form ("AIF") for the year ended December 31, 2011 (see the Additional Information section).

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	**2011**	2010	2009 (Prepared following previous GAAP)
Net cash from (used in)			
Operating activities	**$ 3,273**	$ 2,591	$ 3,039
Investing activities	**(2,530)**	(1,793)	(2,063)
Net cash provided (used) before Financing activities	**743**	798	976
Financing activities	**(558)**	(631)	(977)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**10**	(22)	(32)
Increase (decrease) in cash and cash equivalents	**$ 195**	$ 145	$ (33)

OPERATING ACTIVITIES

Cash from operating activities increased $682 million in 2011 compared to 2010 mainly because of an $864 million increase in cash flow, which is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in non-cash working capital and the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets held for sale, we had working capital of $283 million at December 31, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet our payment obligations.

INVESTING ACTIVITIES

Cash used for investing activities in 2011 increased $737 million from 2010. The increase is primarily due to higher capital expenditures, which increased by $591 million and decreased proceeds from divestiture of assets of $136 million. Capital expenditures are further discussed under Net Capital Investment within the Financial Information section and Capital Investment within the Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

In September 2011, we renegotiated our existing $2.5 billion committed bank credit facility, increasing the facility to $3.0 billion and extending the maturity date to November 30, 2015. In addition, the standby fees required to maintain the facility and the cost of future borrowings were reduced. We also have a commercial paper program which, together with the committed credit facility, may be used to manage our short-term cash requirements. At December 31, 2011, we had no short-term borrowings (2010 and 2009 – nil) in the form of commercial paper. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus. The Canadian debt shelf prospectus expires in July 2012 and the U.S. debt shelf prospectus in August 2012. It is our intention to renew both prospectuses prior to their expiration.

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 then finally to growth capital. In 2011, we declared and paid quarterly dividends of $0.20 per share (2010 – $0.20 per share; 2009 – US$0.20 per share in the fourth quarter) for total dividend payments of $603 million (2010 - $601 million; 2009 - $159 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2011 decreased by $73 million from 2010. The decrease in 2011 was primarily due to $58 million of revolving long-term debt payments in 2010 compared to none in 2011 and higher proceeds on the issuance of common shares in 2011, which were as a result of stock option exercises. Our long-term debt was $3,527 million as at December 31, 2011 (2010 - $3,432 million; 2009 - $3,656 million). There are no payments of principal due until September 2014 ($814 million).

As at December 31, 2011, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	December 31,		
	2011	2010	2009
Debt to Capitalization	**27%**	29%	32% [1]
Debt to Adjusted EBITDA (times)	**1.0x**	1.3x	0.9x [2]

(1) The 2009 Debt to Capitalization ratio has been calculated as at January 1, 2010 on an IFRS basis.

(2) The 2009 Debt to Adjusted EBITDA ratio has been calculated on a previous GAAP basis.

In 2011, driven by strong operational results, our financial position has improved as measured by our debt to capitalization and debt to adjusted EBITDA metrics both of which are at or below the low end of our target ranges.

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 our non-GAAP measure of capitalization as debt plus shareholders' equity.

Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before finance costs, interest income, income tax expense, DD&A, 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 as measures of our overall financial strength.

In order to increase comparability of debt to adjusted EBITDA between periods and remove the non-cash component of risk management activities, we changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for 2010 and 2009 have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

We continue to target a debt to capitalization ratio of between 30 to 40 percent and a debt to adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at December 31, 2011, approximately 754.5 million common shares were outstanding (2010 – 752.7 million; 2009 – 751.3 million) and no preferred shares were outstanding. The increase in common shares in 2011 was the result of stock option exercises. No other issuance of common shares has occurred in 2011.

We have in place a Board approved dividend reinvestment plan ("DRIP"), which permits holders of common shares to automatically reinvest all or any portion of their cash dividends paid on their common shares in additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the years ended December 31, 2011 and 2010, common shares were purchased on the market to meet our DRIP requirements.

LONG-TERM INCENTIVE PLANS

The Cenovus Stock Option Plan ("ESOP") permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our common shares. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the ESOP are exercisable at 30 percent of the 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 granted prior to February 24, 2011 have an associated tandem share appreciation right ("TSAR"), which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our common shares over the exercise period of their option in exchange for surrendering their option. A portion of the options have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. The performance-based options that do not vest when eligible are forfeited. The exercise of an option as a TSAR for a cash payment does not result in the issuance of any additional common shares, thus having no dilutive effect.

Options granted on or after February 24, 2011 have associated net settlement rights ("NSR"). The NSRs, 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 our common shares at the time of exercise over the exercise price of the option.

The TSARs and NSRs vest and expire under the same terms and conditions as the underlying options.

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

No further Cenovus replacement options will be granted to Encana employees. Encana is required to reimburse Cenovus in respect of cash payments made to Encana employees for Cenovus replacement options exercised as TSARs. Cenovus is required to reimburse Encana in respect of cash payments made to Cenovus employees for Encana replacement options exercised as TSARs. No further Encana replacement options will be granted to Cenovus employees.

The following is a summary of long-term incentives outstanding at year end:

	2011		2010		2009	
	Units [1]	Price [2]	Units [1]	Price [2]	Units [1]	Price [2]
TSARs						
- outstanding	**14,921**	**$ 28.12**	19,117	$ 27.75	16,455	$ 27.52
- exercisable	**8,874**	**$ 29.15**	7,734	$ 28.07	6,107	$ 25.68
NSRs						
- outstanding	**5,809**	**$ 36.95**	–	–	–	–
- exercisable	**1**	**$ 37.54**	–	–	–	–
Cenovus Replacement TSARs [3]						
- outstanding	**9,686**	**$ 28.96**	17,154	$ 28.16	22,945	$ 27.14
- exercisable	**7,522**	**$ 29.73**	10,805	$ 27.88	9,972	$ 25.29
Encana Replacement TSARs [4]						
- outstanding	**10,411**	**$ 31.97**	13,527	$ 31.17	16,357	$ 30.46
- exercisable	**8,461**	**$ 32.64**	8,066	$ 30.85	6,076	$ 28.43

(1) Thousands of units.
(2) Weighted average exercise price.
(3) Held by Encana Employees.
(4) Held by Cenovus Employees.

The closing share price at December 31, 2011 for Cenovus was $33.83 and for Encana was $18.89.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

	Expected Payment Date						
($ millions)	2012	2013	2014	2015	2016	2017+	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
Decommissioning liabilities	69	2	7	2	2	6,458	6,540
Long-term debt [3]	–	–	814	–	–	2,745	3,559
Partnership Contribution Payable [3]	372	395	419	445	472	122	2,225
Total Payments [4]	$ 1,045	$ 747	$ 1,572	$ 881	$ 929	$ 13,591	$ 18,765
Product Sales	$ 52	$ 54	$ 56	$ 57	$ 60	$ 3	$ 282
Partnership Contribution Receivable [3]	$ 372	$ 393	$ 414	$ 436	$ 460	$ 119	$ 2,194

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Includes commitments related to jointly controlled entities.
(3) Principal component only. See notes to the Consolidated Financial Statements.
(4) Contracts undertaken by the Company on behalf of the FCCL Partnership 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), future building leases, marketing agreements, capital commitments and debt. 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.

Our commitments for 2012 increased by $385 million and in total increased by $2,537 million from 2010 mainly due to increased pipeline transportation commitments. These increased commitments were primarily for increased tolls and new agreements entered into in 2011 for crude oil transportation as we implement our marketing strategy to access new markets for our increasing crude oil production.

As at December 31, 2011, 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 61 Bcf of natural gas at a weighted average price of $4.62 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

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

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk, liquidity risk and cost overruns;
- Operational risks including capital and operating risks, reserves replacement risks and safety and environmental risks; and
- Regulatory risks including regulatory process and approval risks and changes to environmental regulations.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Management monitors our risk strategies to proactively respond to changing economic conditions and to eliminate or mitigate risk. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

A description of the risks 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, 2011 (see Additional Information).

FINANCIAL RISKS

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

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient access to cash resources, including our committed credit facility, is maintained to fund capital expenditures.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of December 31, 2011, are disclosed in the notes to the Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

GLOBAL ECONOMIC ENVIRONMENT

The global economic environment has been turbulent and there continues to be uncertainty surrounding the European sovereign debt crisis. The European financial conditions along with a potential U.S. recession are among our most significant economic concerns.

We believe our financial position is strong with debt metrics currently at or below the low end of our target ranges. In addition, we have a fully available committed credit facility of $3.0 billion and capacity under two shelf prospectuses available to assist in addressing continued economic uncertainty and deteriorating global conditions. We also have a risk mitigation strategy that helps protect a portion of our cash flow each year.

Our ability to react to global economic uncertainties is enhanced by our ability to scale our capital programs to accommodate reduced cash flows.

COMMODITY PRICE RISK

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

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

CREDIT RISK

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

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

LIQUIDITY RISK

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

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2011, no amounts were drawn on our committed credit facility. In addition, we had $1.5 billion in unused capacity under our Canadian shelf prospectus and US$1.5 billion in unused capacity under our U.S. shelf prospectus, the availability of which are dependent on market conditions. Both of these prospectuses expire in the third quarter of 2012 and it is our intention to renew them prior to their expiration.

FOREIGN EXCHANGE RISK

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

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

We also have the flexibility to maintain a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, we may enter into cross currency swaps on a portion of our debt as a means of managing the U.S./Canadian dollar debt mix.

INTEREST RATE RISK

Interest rate risk is the impact of changing interest rates on earnings, cash flows and valuations. Although all of our debt portfolio was fixed rate debt at December 31, 2011, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our commercial paper program and credit facilities. We may also enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

CAPITAL AND OPERATING RISKS

Our ability to operate, generate cash flows, complete projects and value reserves is subject to capital and operating risks, including continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary regulatory, stakeholder and partner approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour and reservoir quality.

In the context of continued market volatility and in the face of the European credit crisis, which could result in a significant global economic recession, we are mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and we identified areas where we could slow down our spending in response to lower cash flows due to lower market prices. We expect to maintain strong financial metrics and substantial liquidity to respond to periods of lower prices if recessionary pressures impact our business.

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 and, therefore, our cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

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

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

SAFETY AND ENVIRONMENTAL RISK

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

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

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

REGULATORY RISKS

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

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

ENVIRONMENTAL REGULATION RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

CLIMATE CHANGE

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

California has implemented climate change regulation in the form of a Low Carbon Fuel Standard that requires the reduction of life cycle carbon emissions from transportation fuels. This regulation currently differentiates oil sands crudes as high carbon intensity crude oils. As an oil sands producer, we are not directly regulated and will not have a compliance obligation; however, refiners in California will be required to meet the legislation. A number of studies produced on the subject, including one that was conducted by an organization that advised the legislation, suggest a wide range of carbon intensity values for oil sands crudes. We are well positioned within the sector given our typically low steam to oil ratio. This legislation has many complexities that are currently being addressed and in December 2011 the U.S. District Court for the Eastern District of California temporarily suspended the enforcement of the legislation due to several pending federal lawsuits challenging its implementation. We continue to monitor this development.

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

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Government of Alberta has set targets for GHG emissions reductions. Regulations require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline. To comply, companies can make operating improvements, purchase carbon offsets (or emission performance credits) or make a $15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus currently has three facilities subject to this regulation. For the 2011 compliance year, we do not anticipate material costs in this regard.

Our efforts with respect to emissions management are founded in our industry leadership in:

- Oil sands technology development to reduce GHG emissions;
- Focus on energy efficiency; and
- Carbon dioxide sequestration.

In particular, our low steam to oil ratios at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

(1) Manage Existing Costs

When regulations are implemented, a cost is placed on our emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.

(2) Respond to Price Signals

As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon reduction, we are also attempting, where appropriate, to realize associated value of our reduction projects.

(3) Anticipate Future Carbon Constrained Scenarios

We continue to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios assist with our long range planning and our analyses on the implications of regulatory trends.

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

We recognize that there is a cost associated with carbon emissions. We believe that GHG regulations and the cost of carbon at various price levels have been adequately taken into consideration as part of our business planning and scenarios analysis. We believe that our development strategy, use of technology and focus on continuous improvement is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect our operations.

Further information regarding Climate Change can be found in the Risk Factors section of our AIF for the year ended December 31, 2011 (see Additional Information).

ALBERTA'S REGULATORY FRAMEWORK

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. An updated draft of the LARP was released on August 29, 2011 after public consultation and stakeholder feedback was obtained. No substantial changes were made to the LARP from these consultations. The LARP is now awaiting provincial cabinet approval prior to being implemented.

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. If the land use designations for conservation, tourism and recreation areas are approved in their current form, 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 that may adversely affect the market price of our securities and the payment of dividends to our shareholders. 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.

As part of the Government of Alberta's competitiveness review, a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project") was initiated in March 2010. The Project's goal is to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. The Project involved engagement with a broad range of stakeholders, including industry and led to a recommendation to the Minister of Energy, in the fourth quarter of 2010, for adoption of a coordinated policy framework and an integrated regulatory system for the upstream oil and gas sector. The Government of Alberta accepted the Project team's recommendations and decided to proceed in implementing those recommendations. There were no new developments in 2011.

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Water. 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.

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 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. In July 2011 we released our first comprehensive corporate responsibility report which 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.

ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates 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 information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

BASIS OF PRESENTATION

Our results for the years ended December 31, 2011 and 2010 and the one month period from December 1, 2009 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

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

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

OIL AND GAS RESERVES

All of our oil and gas reserves were evaluated and reported to Cenovus by the IQREs as at December 31, 2011 in accordance with NI 51-101. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels, and economics of recovery based on cash flow forecasts. These revisions can have a significant impact on our future earnings because they will directly impact our DD&A rates, asset impairment calculations, accounting for business combinations and decommissioning costs.

PROPERTY, PLANT AND EQUIPMENT – DD&A

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit of production method based on estimated proved reserves determined using estimated future prices and costs. As a key component in the calculation of DD&A, the estimates of reserves can have a significant impact on net earnings, as a downward revision in our estimate of reserve quantities could result in a higher DD&A charge to net earnings.

Refining, marketing, corporate and other upstream assets, including pipelines and information technology assets, are depreciated on straight-line basis and are subject to our estimate of useful life and salvage value. These estimates can have a significant impact to net earnings as a decrease in the useful life or a lower salvage value could result in a higher DD&A charge to net earnings.

E&E ASSETS

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material change in the future.

IMPAIRMENT OF 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 impairment test is performed at the cash generating unit ("CGU") for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets. Corporate assets are allocated on a reasonable and consistent manner to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. For refining assets the impairment test is performed at each refinery independently.

The assessment of facts and circumstances that are used for impairment testing to suggest that the carrying amount of the assets may exceed its recoverable amount is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or CGUs for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The recoverable amount calculation requires the use of estimates and assumptions which are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs. Details on the assumptions used in determining the recoverable amount can be found in the notes to the Consolidated Financial Statements.

EXCHANGES OF ASSETS

Fair value estimates, which are used to determine the carrying value of a PP&E or E&E asset and recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

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. 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.

DECOMMISSIONING LIABILITIES

Provisions are recognized for the future decommissioning and restoration of our upstream oil and gas assets and refining assets at the end of their economic lives. Assumptions, based on current economic factors and experience to date which we believe are reasonable, have been made to estimate the future liability. 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. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, we determine 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. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

COMPENSATION PLANS

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to our best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under our compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

INCOME TAX PROVISIONS

Tax regulations and legislations and their interpretations in the various jurisdictions that we operate 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. 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.

FINANCIAL INSTRUMENTS

The fair value of derivatives, which may be used to manage commodity price, foreign currency and interest rate exposures, are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Our assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and are therefore subject to measurement uncertainty.

IFRS TRANSITION

OPENING BALANCE SHEET – CARRYING VALUE OF REFINERIES

On transition to IFRS, we elected to measure the carrying value of our refineries at their then estimated fair value, which permanently reduced their carrying value by approximately $2.6 billion. The fair value estimate is deemed to be the carrying value of the refineries at January 1, 2010. The reduced carrying value impacts DD&A expense recorded in future periods. DD&A expense for the year ended December 31, 2010 was reduced by $103 million as a result of the reduced carrying value.

OPENING BALANCE SHEET – FULL COST POOL

Under previous GAAP, we accounted for our oil and gas properties in one cost centre using full cost accounting. IFRS has no equivalent treatment. IFRS 1 - First-time Adoption of IFRS, permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Applying this exemption, the cost of our E&E assets were reclassified from PP&E to the new E&E asset category, and the remainder of our full cost pool was allocated using the estimated proved reserve values discounted at 10 percent at the transition date. This approach was consistent with the allocation method which was required to be used in our formation as part of the Arrangement. The IFRS allocation process did not affect the net book value of our PP&E at the date of transition as no IFRS impairments were recognized.

Under both IFRS and previous GAAP, the DD&A on our development and production PP&E is calculated using the unit-of-production method based on estimated proved reserves. However, under previous GAAP, we calculated our DD&A rate at the country cost centre level whereas under IFRS, our DD&A rates are calculated at the area level. The adoption of this policy resulted in a $135 million increase in our DD&A for the year ended December 31, 2010.

FUTURE CHANGES IN ACCOUNTING POLICIES

JOINT ARRANGEMENTS AND OFF BALANCE SHEET ACTIVITIES

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 and focuses on the need to have power and variable returns for control to be present. 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"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts 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. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.
- 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. Early adoption is permitted, providing the five standards are adopted concurrently. We are currently evaluating the impact of adopting these standards on our Consolidated Financial Statements.

EMPLOYEE BENEFITS

In June 2011, the IASB amended IAS 19, *"Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates and the valuation of plan assets, will be recognized in OCI. Furthermore, 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 amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting these amendments on our Consolidated Financial Statements.

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. We are currently evaluating the impact of adopting IFRS 13 on our 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. We are currently evaluating the impact of adopting IFRS 9 on our 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. We are currently evaluating the impact of adopting this amendment on our 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. We are currently evaluating the impact of adopting the amendments to IAS 7 and IFRS 32 on our Consolidated Financial Statements.

OUTLOOK

In early 2012, certain economic factors have created optimism that the U.S. economy will gradually improve throughout the year. However, the European sovereign debt situation is expected to continue and may inhibit the North American economic recovery. Our outlook for 2012 depends on commodity prices including the effect of new market access for North American crude oil. Crude oil prices are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

For 2012, the price of WTI is expected to remain close to the average in 2011 as increased demand driven by emerging markets is anticipated to be offset by the return of Libyan supply. The expected increase in demand however remains sensitive to events in Europe as its sovereign debt problems continues to unfold. Also, the potential of further political uncertainty in Middle Eastern and northern African countries could create a material risk of supply disruptions which would negate the effect of returning Libyan supply.

For 2012, the WTI-WCS differential is expected to face pressures to narrow compared to 2011 as new coking capacity at our Wood River Refinery will be in operation for the full year and other additional refining capacity is brought on in the latter part of the year. These pressures are expected to be offset by growing North American crude oil production which will lead to greater pipeline congestion. However, new rail capacity, especially out of North Dakota, will serve to reduce pipeline congestion.

The economics for U.S. Midwest refineries for 2012 are expected to be lower than 2011 as average crack spreads decrease. The expected decrease in crack spreads is mostly due to lower discounts on feedstock costs as inland crude oil finds an outlet to refineries on the Gulf of Mexico through the Seaway Pipeline reversal in the middle of 2012.

For 2012 our strategic initiatives and key priorities include:

- Growth of production at Christina Lake with ramp up of phase C production and expected first production at phase D in the fourth quarter of 2012;
- Conventional crude oil production increasing in 2012 primarily as a result of the development of our tight oil opportunities at Lower Shaunavon and Bakken while pursuing additional growth opportunities;
- Improved production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Investment in the dewatering pilot project at Telephone Lake and the drilling of a second well pair as part of the Grand Rapids pilot project;
- Progressing the Telephone Lake and area project;
- Anticipating regulatory and partner approval for Narrows Lake phases A, B and C, perform additional engineering and start construction;
- Committing to transportation initiatives and advance new and expanded market development initiatives for our crude oil in step with a marketing strategy to deliver on our production growth;
- Progressing environmental strategy by setting internal goals;
- Demonstrating stable and reliable CORE operations at the Wood River Refinery; and
- Growing our dividend, at the discretion of our Board, while continuing to invest in long-term projects.

While we do not anticipate a significant impact to our business, our partner ConocoPhillips, announced its intention to split its Refining and Marketing and its Exploration and Production businesses into two stand-alone companies. If the split is completed, we expect our partnership and related agreements with ConocoPhillips to be amended to accommodate the separation and holding of the upstream assets and refining assets in two separate companies.

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

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our 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, emphasis on environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core assets with any incremental cash requirements covered by additional debt financing;
- Lowering our commodity price risk profile through natural gas and refining integration as well as a consistent risk management hedging strategy; and
- Maintain a sustainable dividend with a priority expected to be placed on growing the dividend as part of delivering a solid total shareholder return.

Our updated business plan outlines our targets of reaching net oil sands 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. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, access to markets, 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.

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. We will continue to develop our strategy with respect to capital investment and returns to shareholders. 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. ("Cenovus") 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, 2011. 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, 2011.

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, 2011 as stated in their Auditor's Report dated February 15, 2012. PricewaterhouseCoopers LLP has provided such opinions.

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

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

February 15, 2012

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CENOVUS ENERGY INC.

We have completed an integrated audit of Cenovus Energy Inc.'s 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 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, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of earnings and comprehensive income, shareholders' equity and cash flows for the years ended December 31, 2011 and 2010, 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, 2011, December 31, 2010 and January 1, 2010 and its financial performance and cash flows for the years ended December 31, 2011 and 2010 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, 2011, 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 Management's Assessment of Internal Controls over Financial Reporting.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our 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, 2011 based on criteria established in Internal Control–Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Chartered Accountants
Calgary, Alberta, Canada

February 15, 2012

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, ($ millions, except per share amounts)	Notes	2011	2010*
Revenues	1		
Gross Sales		**16,185**	13,090
Less: Royalties		**489**	449
		15,696	12,641
Expenses	1		
Purchased product		**9,090**	7,551
Transportation and blending		**1,369**	1,065
Operating		**1,406**	1,286
Production and mineral taxes		**36**	34
(Gain) loss on risk management	31	**(248)**	(324)
Depreciation, depletion and amortization		**1,295**	1,302
Exploration expense		**–**	3
General and administrative		**295**	246
Finance costs	5	**447**	498
Interest income	6	**(124)**	(144)
Foreign exchange (gain) loss, net	7	**26**	(51)
(Gain) loss on divestiture of assets	17	**(107)**	(116)
Other (income) loss, net		**4**	(13)
Earnings Before Income Tax		**2,207**	1,304
Income tax expense	8	**729**	223
Net Earnings		**1,478**	1,081
Other Comprehensive Income (Loss), Net of Tax			
Foreign currency translation adjustment		**48**	71
Comprehensive Income		**1,526**	1,152
Net Earnings per Common Share	9		
Basic		**1.96**	1.44
Diluted		**1.95**	1.43

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at ($ millions)	Notes	**December 31, 2011**	December 31, 2010*	January 1, 2010*
Assets				
Current Assets				
Cash and cash equivalents	10	**495**	300	155
Accounts receivable and accrued revenues	11	**1,405**	1,059	982
Income tax receivable		**–**	31	40
Current portion of Partnership Contribution Receivable	12	**372**	346	345
Inventories	13	**1,291**	880	875
Risk management	31	**232**	163	60
Assets held for sale	14	**116**	65	–
Current Assets		**3,911**	2,844	2,457
Exploration and Evaluation Assets	1,15	**880**	713	580
Property, Plant and Equipment, net	1,16	**14,324**	12,627	12,049
Partnership Contribution Receivable	12	**1,822**	2,145	2,621
Risk Management	31	**52**	43	1
Income Tax Receivable		**29**	–	–
Other Assets	18	**44**	281	192
Deferred Income Taxes	8	**–**	55	3
Goodwill	1,19	**1,132**	1,132	1,146
Total Assets		**22,194**	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	20	**2,579**	1,843	1,605
Income tax payable		**329**	154	–
Current portion of Partnership Contribution Payable	12	**372**	343	340
Risk management	31	**54**	163	70
Liabilities related to assets held for sale	14	**54**	7	–
Current Liabilities		**3,388**	2,510	2,015
Long-Term Debt	21	**3,527**	3,432	3,656
Partnership Contribution Payable	12	**1,853**	2,176	2,650
Risk Management	31	**14**	10	4
Decommissioning Liabilities	22	**1,777**	1,399	1,185
Other Liabilities	23	**128**	346	246
Deferred Income Taxes	8	**2,101**	1,572	1,484
Total Liabilities		**12,788**	11,445	11,240
Commitments and Contingencies	33			
Shareholders' Equity		**9,406**	8,395	7,809
Total Liabilities and Shareholders' Equity		**22,194**	19,840	19,049

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board

M.A. Grandin

Colin Taylor

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**	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**

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.
** Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, ($ millions)	Notes	2011	2010*
Operating Activities			
Net earnings		**1,478**	1,081
Depreciation, depletion and amortization		**1,295**	1,302
Deferred income taxes	8	**575**	141
Cash tax on divestiture of assets		**13**	–
Unrealized (gain) loss on risk management	31	**(180)**	(46)
Unrealized foreign exchange (gain) loss	7	**(42)**	(69)
(Gain) loss on divestiture of assets	17	**(107)**	(116)
Unwinding of discount on decommissioning liabilities	5,22	**75**	75
Other		**169**	44
		3,276	2,412
Net change in other assets and liabilities		**(82)**	(55)
Net change in non-cash working capital		**79**	234
Cash From Operating Activities		**3,273**	2,591
Investing Activities			
Capital expenditures – exploration and evaluation assets	15	**(527)**	(350)
Capital expenditures – property, plant and equipment	16	**(2,265)**	(1,851)
Proceeds from divestiture of assets		**173**	309
Cash tax on divestiture of assets		**(13)**	–
Net change in investments and other		**(28)**	4
Net change in non-cash working capital		**130**	95
Cash (Used in) Investing Activities		**(2,530)**	(1,793)
Net Cash Provided (Used) before Financing Activities		**743**	798
Financing Activities			
Net issuance (repayment) of short-term borrowings		**(9)**	–
Net issuance (repayment) of revolving long-term debt		**–**	(58)
Proceeds on issuance of common shares		**48**	28
Dividends paid on common shares	9	**(603)**	(601)
Other		**6**	–
Cash From (Used in) Financing Activities		**(558)**	(631)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**10**	(22)
Increase (Decrease) in Cash and Cash Equivalents		**195**	145
Cash and Cash Equivalents, Beginning of Year		**300**	155
Cash and Cash Equivalents, End of Year		**495**	300

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

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, 2011

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 #4000, 421 - 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. Information on the Company's basis of presentation for these financial statements is found in Note 2.

The Company's reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's 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, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains 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,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**3,291**	2,702	**2,328**	2,284	**10,625**	8,228
Less: Royalties	**284**	279	**205**	170	**–**	–
	3,007	2,423	**2,123**	2,114	**10,625**	8,228
Expenses						
Purchased product	**–**	–	**–**	–	**9,149**	7,674
Transportation and blending	**1,231**	935	**138**	130	**–**	–
Operating	**438**	367	**488**	434	**481**	488
Production and mineral taxes	**–**	–	**36**	34	**–**	–
(Gain) loss on risk management	**70**	(10)	**(152)**	(258)	**14**	(10)
Operating Cash Flow	**1,268**	1,131	**1,613**	1,774	**981**	76
Depreciation, depletion and amortization	**347**	375	**778**	799	**130**	96
Exploration expense	**–**	3	**–**	–	**–**	–
Segment Income (Loss)	**921**	753	**835**	975	**851**	(20)

	Corporate and Eliminations		Consolidated	
For the years ended December 31,	**2011**	2010	**2011**	2010
Revenues				
Gross Sales	**(59)**	(124)	**16,185**	13,090
Less: Royalties	**–**	–	**489**	449
	(59)	(124)	**15,696**	12,641
Expenses				
Purchased product	**(59)**	(123)	**9,090**	7,551
Transportation and blending	**–**	–	**1,369**	1,065
Operating	**(1)**	(3)	**1,406**	1,286
Production and mineral taxes	**–**	–	**36**	34
(Gain) loss on risk management	**(180)**	(46)	**(248)**	(324)
	181	48	**4,043**	3,029
Depreciation, depletion and amortization	**40**	32	**1,295**	1,302
Exploration expense	**–**	–	**–**	3
Segment Income (Loss)	**141**	16	**2,748**	1,724
General and administrative	**295**	246	**295**	246
Finance costs	**447**	498	**447**	498
Interest income	**(124)**	(144)	**(124)**	(144)
Foreign exchange (gain) loss, net	**26**	(51)	**26**	(51)
(Gain) loss on divestiture of assets	**(107)**	(116)	**(107)**	(116)
Other (income) loss, net	**4**	(13)	**4**	(13)
	541	420	**541**	420
Earnings Before Income Tax			**2,207**	1,304
Income tax expense			**729**	223
Net Earnings			**1,478**	1,081

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

	Exploration and Evaluation Assets			Property, Plant and Equipment		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**741**	570	452	**6,224**	5,219	4,870
Conventional	**139**	143	128	**4,668**	4,409	4,645
Refining and Marketing	**–**	–	–	**3,200**	2,853	2,418
Corporate and Eliminations	**–**	–	–	**232**	146	116
Consolidated	**880**	713	580	**14,324**	12,627	12,049

	Goodwill			Total Assets		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**10,524**	9,487	9,426
Conventional	**393**	393	407	**5,566**	5,186	5,453
Refining and Marketing	**–**	–	–	**4,927**	4,282	3,669
Corporate and Eliminations	**–**	–	–	**1,177**	885	501
Consolidated	**1,132**	1,132	1,146	**22,194**	19,840	19,049

CAPITAL EXPENDITURES

For the years ended December 31,	**2011**	2010
Capital		
Oil Sands	**1,415**	857
Conventional	**788**	526
Refining and Marketing	**393**	656
Corporate	**127**	76
	2,723	2,115
Acquisition Capital		
Oil Sands	**44**	23
Conventional	**25**	25
Refining and Marketing	**–**	38
Corporate	**2**	–
Total	**2,794**	2,201

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, 2011, Cenovus had two customers (2010 – two) which individually accounted for more than 10 percent of its consolidated gross revenues. Sales to these customers, major international integrated energy companies with an investment grade credit rating, were approximately $7,324 million and $2,683 million respectively (2010 – $5,376 million and $2,295 million).

B) FINANCIAL RESULTS BY UPSTREAM PRODUCT

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
For the years ended December 31,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**3,217**	2,610	**1,492**	1,229	**4,709**	3,839
Less: Royalties	**282**	276	**193**	153	**475**	429
	2,935	2,334	**1,299**	1,076	**4,234**	3,410
Expenses						
Transportation and blending	**1,229**	934	**104**	86	**1,333**	1,020
Operating	**409**	339	**244**	199	**653**	538
Production and mineral taxes	**–**	–	**27**	28	**27**	28
(Gain) loss on risk management	**87**	14	**43**	5	**130**	19
Operating Cash Flow	**1,210**	1,047	**881**	758	**2,091**	1,805

	Natural Gas					
	Oil Sands		Conventional		Total	
For the years ended December 31,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**63**	78	**825**	1,042	**888**	1,120
Less: Royalties	**2**	1	**12**	17	**14**	18
	61	77	**813**	1,025	**874**	1,102
Expenses						
Transportation and blending	**2**	1	**34**	44	**36**	45
Operating	**24**	23	**240**	231	**264**	254
Production and mineral taxes	**–**	–	**9**	6	**9**	6
(Gain) loss on risk management	**(17)**	(24)	**(195)**	(263)	**(212)**	(287)
Operating Cash Flow	**52**	77	**725**	1,007	**777**	1,084

	Other					
	Oil Sands		Conventional		Total	
For the years ended December 31,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**11**	14	**11**	13	**22**	27
Less: Royalties	**–**	2	**–**	–	**–**	2
	11	12	**11**	13	**22**	25
Expenses						
Transportation and blending	**–**	–	**–**	–	**–**	–
Operating	**5**	5	**4**	4	**9**	9
Production and mineral taxes	**–**	–	**–**	–	**–**	–
(Gain) loss on risk management	**–**	–	**–**	–	**–**	–
Operating Cash Flow	**6**	7	**7**	9	**13**	16

B) FINANCIAL RESULTS BY UPSTREAM PRODUCT *(Continued)*

	Oil Sands		Total Conventional		Total	
For the years ended December 31,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**3,291**	2,702	**2,328**	2,284	**5,619**	4,986
Less: Royalties	**284**	279	**205**	170	**489**	449
	3,007	2,423	**2,123**	2,114	**5,130**	4,537
Expenses						
Transportation and blending	**1,231**	935	**138**	130	**1,369**	1,065
Operating	**438**	367	**488**	434	**926**	801
Production and mineral taxes	**–**	–	**36**	34	**36**	34
(Gain) loss on risk management	**70**	(10)	**(152)**	(258)	**(82)**	(268)
Operating Cash Flow	**1,268**	1,131	**1,613**	1,774	**2,881**	2,905

C) GEOGRAPHIC INFORMATION

	Canada		United States		Consolidated	
For the years ended December 31,	**2011**	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**7,513**	6,466	**8,672**	6,624	**16,185**	13,090
Less: Royalties	**489**	449	**–**	–	**489**	449
	7,024	6,017	**8,672**	6,624	**15,696**	12,641
Expenses						
Purchased product	**1,867**	1,456	**7,223**	6,095	**9,090**	7,551
Transportation and blending	**1,369**	1,065	**–**	–	**1,369**	1,065
Operating	**947**	814	**459**	472	**1,406**	1,286
Production and mineral taxes	**36**	34	**–**	–	**36**	34
(Gain) loss on risk management	**(255)**	(322)	**7**	(2)	**(248)**	(324)
	3,060	2,970	**983**	59	**4,043**	3,029
Depreciation, depletion and amortization	**1,165**	1,216	**130**	86	**1,295**	1,302
Exploration expense	**–**	3	**–**	–	**–**	3
Segment Income (Loss)	**1,895**	1,751	**853**	(27)	**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 $700 million (2010 – $646 million).

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

	Exploration and Evaluation Assets			Property, Plant and Equipment		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Canada	**880**	713	580	**11,124**	9,774	9,645
United States	**–**	–	–	**3,200**	2,853	2,404
Consolidated	**880**	713	580	**14,324**	12,627	12,049

	Goodwill			Total Assets		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Canada	**1,132**	1,132	1,146	**17,536**	15,906	15,669
United States	**–**	–	–	**4,658**	3,934	3,380
Consolidated	**1,132**	1,132	1,146	**22,194**	19,840	19,049

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 represent the Company's first annual financial statements 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. The Company's accounting policies have been applied consistently to all years presented with the exception of certain IFRS 1, *"First-time Adoption of International Financial Reporting Standards"* ("IFRS 1") transition elections and exemptions the Company applied in its transition from Canadian generally accepted accounting principles ("previous GAAP") as discussed in Note 34. The impact of the transition to IFRS on the Company's financial position, results of operation and cash flows from the Consolidated Financial Statements for the year ended December 31, 2010 prepared under previous GAAP is included in Note 34.

After applying the transition exemptions of IFRS 1, 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.

The Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Board of Directors on February 14, 2012.

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 delivered and the services provided.

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 COSTS

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 accumulated costs are expensed as exploration expense.

H) EMPLOYEE BENEFIT PLANS

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

The cost of pensions and other post-employment benefits is actuarially determined using the projected 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. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over ten 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 plans is recorded as the benefits are earned by the employees covered by the plans.

I) INCOME TAXES

Income taxes comprise current and deferred tax. 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 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, in which case the deferred income tax is also recorded in equity.

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 the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options 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 principally be 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/area/project is determined or the assets are determined to be impaired.

Once technical feasibility and commercial viability have been established for a field/area/project 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/area/project 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 lives of each component of the refineries. 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 lives of each component are reviewed annually and adjusted, if appropriate.

OTHER ASSETS

Costs associated with office furniture, fixtures, leasehold improvements, information technology, marine terminal facilities 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. 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. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses 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 Statement 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 and the loss event has an impact on future cash flow and 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 is recognized on a financial asset carried at amortized cost 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 Statement of Earnings and Comprehensive Income.

S) LEASES

Leases in which substantially all 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 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 estimated liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to estimated timing or future decommissioning cost estimates 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 tax.

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 the 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 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 the Cenovus 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 Statement 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 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 the 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 at the settlement date using the effective interest method of amortization.

AVAILABLE FOR SALE FINANCIAL ASSETS

"Available for sale financial assets" are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income. 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 2011.

AA) RECENT ACCOUNTING PRONOUNCEMENTS

JOINT ARRANGEMENTS AND OFF BALANCE SHEET ACTIVITIES

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 and focuses on the need to have power and variable returns for control to be present. 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"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts 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. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.
- 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. Early adoption is permitted, providing the five standards are adopted concurrently. The Company is currently evaluating the impact of adopting these standards on its Consolidated Financial Statements.

EMPLOYEE BENEFITS

In June 2011, the IASB amended IAS 19, *"Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates or the valuation of plan assets, will be recognized in OCI. Furthermore, 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 amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Earlier adoption is permitted. The Company is currently evaluating the impact of adopting these amendments on its Consolidated Financial Statements.

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. The Company is currently evaluating the impact of adopting IFRS 13 on its 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. 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 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 Company is currently evaluating the impact of adopting this amendment on its 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. The Company is currently evaluating the impact of adopting the amendments to IFRS 7 and IAS 32 on its Consolidated Financial Statements.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

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. Significant judgments, estimates and assumptions made by Management in the preparation of these Consolidated Financial Statements are outlined below.

CARRYING VALUE OF PROPERTY, PLANT AND EQUIPMENT

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the Consolidated Financial Statements of future periods could be material.

Refining, marketing, other upstream and corporate assets are depreciated on a straight-line basis and are subject to Management's estimate of useful life and salvage value. Changes to the estimated useful life and salvage value could have a material impact on the Consolidated Financial Statements of future periods.

CARRYING VALUE OF 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 and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

DECOMMISSIONING COSTS

Provisions are recognized for the future decommissioning and restoration of the Company's upstream oil and 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. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. 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.

IMPAIRMENT OF ASSETS

The recoverable amounts of CGUs and individual assets have been determined as the greater of an asset's or CGU's value-in-use and fair value less costs to sell. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

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

At December 31, 2011, 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 reserve evaluators, oil and natural gas prices and the discount rate.

RESERVES

Reserve estimates are dependent on a number of variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs and estimated selling price of the hydrocarbons produced. Changes in these variables could significantly impact the reserve estimates. The Company's oil and gas reserves are evaluated and reported to the Company by independent qualified reserves evaluators.

OIL AND NATURAL GAS PRICES

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

	2012	2013	2014	2015	2016	Average Annual % Change to 2023
WTI (US$/barrel)	97.50	97.50	100.00	100.80	101.70	1.3%
AECO ($/Mcf)	3.50	4.20	4.70	5.10	5.55	3.5%

DISCOUNT RATE

A discount rate of 10 percent has been used to determine the present value of future cash flows. Changes in the economic conditions could significantly change the estimated recoverable amount.

EMPLOYEE BENEFIT PLANS AND POST-EMPLOYMENT BENEFITS

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

COMPENSATION PLANS

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under the Cenovus compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

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. 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.

CONTINGENCIES

Contingencies, by their nature, are subject to measurement uncertainty as the financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies involves a significant amount of judgment including assessing whether a present obligation exists and providing a reliable estimate of the amount of cash outflow required to settle the obligation. The uncertainty involved with the timing and amount at which a contingency will be settled may have a material impact on the Consolidated Financial Statements of future periods to the extent that the amount provided for differs from the actual outcome.

FINANCIAL INSTRUMENTS

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Company may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

5. FINANCE COSTS

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

6. INTEREST INCOME

For the years ended December 31,	**2011**	2010
Interest Income – Partnership Contribution Receivable	**120**	144
Other	**4**	–
	124	144

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2011**	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:		
U.S. dollar debt issued from Canada	**78**	(182)
U.S. dollar Partnership Contribution Receivable issued from Canada	**(107)**	91
Other	**(13)**	22
Unrealized Foreign Exchange (Gain) Loss	**(42)**	(69)
Realized Foreign Exchange (Gain) Loss	**68**	18
	26	(51)

8. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31,	**2011**	2010
Current Tax		
Canada	**150**	82
United States	**4**	–
Total Current Tax	**154**	82
Deferred Tax	**575**	141
	729	223

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

For the years ended December 31,	**2011**	2010
Earnings Before Income Tax	**2,207**	1,304
Canadian Statutory Rate	**26.7%**	28.2%
Expected Income Tax	**589**	368
Effect of Taxes Resulting from:		
Foreign tax rate differential	**78**	(22)
Non-deductible stock-based compensation	**18**	34
Multi-jurisdictional financing	**(50)**	(93)
Foreign exchange gains (losses) not included in net earnings	**(9)**	28
Non-taxable capital (gains) losses	**(9)**	(13)
Capital losses	**26**	(107)
Adjustments arising from prior year tax filings	**31**	26
Other	**55**	2
	729	223
Effective Tax Rate	**33.0%**	17.1%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

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

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Deferred Income Tax Liabilities			
Deferred tax liabilities (assets) to be settled (recovered) within 12 months	**117**	57	(68)
Deferred tax liabilities to be settled after more than 12 months	**1,984**	1,515	1,552
	2,101	1,572	1,484
Deferred Income Tax Assets			
Deferred tax assets to be recovered within 12 months	**–**	(3)	–
Deferred tax assets to be recovered after more than 12 months	**–**	(52)	(3)
	–	(55)	(3)
Net Deferred Income Tax Liability	**2,101**	1,517	1,481

For the purposes of the above table, deferred income tax assets are shown net of offsetting deferred income tax liabilities where these occur in the same entity and jurisdiction. The deferred income tax liabilities and assets to be settled (recovered) 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 other comprehensive income	(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 other comprehensive income	18	–	–	–	2	20
As at December 31, 2011	**2,394**	**163**	**112**	**71**	**132**	**2,872**

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 other comprehensive income	8	–	–	8
As at December 31, 2010	(281)	(45)	(170)	(496)
Charged/(credited) to earnings	(270)	29	(21)	(262)
Charged/(credited) to other comprehensive income	(13)	–	–	(13)
As at December 31, 2011	**(564)**	**(16)**	**(191)**	**(771)**

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 other comprehensive income	(103)
Net Deferred Income Tax Liabilities as at December 31, 2010	1,517
Charged/(credited) to earnings	577
Charged/(credited) to other comprehensive income	7
Net Deferred Income Tax Liabilities as at December 31, 2011	**2,101**

The allocation of deferred income tax expense is comprised of:

As at	**December 31, 2011**	December 31, 2010
Credited/(charged) to net deferred income tax liabilities	**577**	137
Credited/(charged) to liabilities related to assets held for sale	**(2)**	4
Deferred Income Tax Expense	**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, 2011**	December 31, 2010	January 1, 2010
Canada	**4,471**	4,239	3,754
United States	**2,740**	3,082	2,637
	7,211	7,321	6,391

At December 31, 2011, the above tax pools included $78 million (December 31, 2010 – $236 million, January 1, 2010 – $491 million) of Canadian non-capital losses and $1,479 million (December 31, 2010 – $607 million, January 1, 2010 – $232 million) of U.S. net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2011 tax pools are Canadian net capital losses totaling $759 million (December 31, 2010 – $983 million, January 1, 2010 – $51 million) which are available for carry forward to reduce future capital gains. Of these losses, $286 million are unrecognized as a deferred income tax asset at December 31, 2011 (December 31, 2010 – $415 million). Recognition is dependent on the level of future capital gains.

9. PER SHARE AMOUNTS

A) NET EARNINGS PER SHARE

	December 31, 2011			December 31, 2010		
For the years ended ($ millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	**1,478**	**754.0**	**$1.96**	1,081	751.9	$1.44
Dilutive effect of Cenovus TSARs	**–**	**3.7**		–	2.1	
Dilutive effect of NSRs	**–**	**–**		–	–	
Net earnings per share – diluted	**1,478**	**757.7**	**$1.95**	1,081	754.0	$1.43

B) DIVIDENDS PER SHARE

The dividends paid in 2011 and 2010 were $603 million ($0.80 per share) and $601 million ($0.80 per share) respectively. The Cenovus Board of Directors declared a first quarter 2012 dividend of $0.22 per share, payable on March 30, 2012, to common shareholders of record as of March 15, 2012.

10. CASH AND CASH EQUIVALENTS

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Cash	**232**	160	76
Short-Term Investments	**263**	140	79
	495	300	155

11. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Accruals	**801**	606	409
Trade	**251**	242	395
Joint Operations with Partners	**30**	32	32
Prepaids and Deposits	**34**	24	20
Interest	**28**	32	38
Other	**261**	123	88
	1,405	1,059	982

12. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In connection with the Arrangement with Encana (Note 1), Cenovus acquired Encana's assets which are jointly controlled with ConocoPhillips. On January 2, 2007, Encana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consisted of an upstream entity and a refining entity. The upstream entity contribution included assets from Encana, primarily the Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable (Partnership Contribution Receivable) contributed from ConocoPhillips of an equal amount. For the refining entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Encana contributed a note payable (Partnership Contribution Payable) of US$7.5 billion.

These entities are accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments (Note 29).

PARTNERSHIP CONTRIBUTION RECEIVABLE

This note receivable is denominated in US$ and bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Receivable shown in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of payments to date.

MANDATORY RECEIPTS – PARTNERSHIP CONTRIBUTION RECEIVABLE

	2012	2013	2014	2015	2016	Thereafter	**Total**
US$	366	386	407	429	452	117	**2,157**
C$ equivalent	372	393	414	436	460	119	**2,194**

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

	2012	2013	2014	2015	2016	Thereafter	**Total**
US$	366	388	412	437	464	121	**2,188**
C$ equivalent	372	395	419	445	472	122	**2,225**

In addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities include equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements. At December 31, 2011 these amounts were $nil (December 31, 2010 – $274 million, January 1, 2010 – $183 million) (Notes 18 and 23).

13. INVENTORIES

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Product			
Refining and Marketing	**1,079**	779	772
Oil Sands	**186**	80	84
Conventional	**1**	–	–
Parts and Supplies	**25**	21	19
	1,291	880	875

The total amount of inventories recognized as an expense during the year was $7,189 million (2010 – $5,997 million).

14. ASSETS AND LIABILITIES HELD FOR SALE

Assets and liabilities classified as held for sale consisted of the following:

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Assets Held for Sale			
Property, plant and equipment	**116**	65	–
Liabilities Related to Assets Held for Sale			
Decommissioning liabilities	**54**	5	–
Deferred income taxes	**–**	2	–
	54	7	–

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, resulting in an impairment loss of approximately $2 million which has been recorded as additional depreciation, depletion and amortization in the Consolidated Statement of Earnings and Comprehensive Income. These assets and the related liabilities are reported in the Conventional segment.

In January 2012, the Company completed the sale of the natural gas assets to an unrelated third party for net proceeds of $63 million.

MARINE TERMINAL FACILITIES

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million. The net assets were recorded at estimated fair value less costs to sell and classified as held for sale. These assets and liabilities were reported in the Refining and Marketing segment. Cenovus recognized a bargain purchase gain of $12 million, resulting from the excess fair value of the net assets acquired over the cash consideration paid. The gain was recorded in other income.

In October 2011, the Company completed the sale of the marine terminal facilities and recorded an after-tax gain on sale of $89 million.

15. EXPLORATION AND EVALUATION ASSETS

	E&E
Cost	
As at January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 16)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
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**

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, 2011 include $15 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2010 – $11 million).

For the year ended December 31, 2011, $356 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 in question (year ended December 31, 2010 – $144 million).

IMPAIRMENT

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statement of Earnings and Comprehensive Income. There were no impairments of E&E assets in 2011 and 2010.

16. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
Cost					
As at January 1, 2010	20,836	134	2,419	427	23,816
Additions	1,061	19	651	136	1,867
Transfers from E&E assets (Note 15)	144	–	–	–	144
Transfers and reclassifications	–	–	–	(92)	(92)
Change in decommissioning liabilities	237	–	22	–	259
Exchange rate movements	(2)	–	(142)	–	(144)
Divestitures	(556)	–	–	(21)	(577)
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**
Accumulated Depreciation, Depletion and Impairment					
As at January 1, 2010	11,342	113	15	297	11,767
Depreciation and depletion expense	1,163	11	72	42	1,288
Transfers and reclassifications	–	–	–	(28)	(28)
Impairment losses	–	–	14	–	14
Exchange rate movements	(1)	–	(4)	–	(5)
Divestitures	(383)	–	–	(7)	(390)
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	1,108	15	85	40	1,248
Impairment losses	2	–	45	–	47
Transfers and reclassifications	(211)	–	(5)	–	(216)
Exchange rate movements	1	–	3	–	4
As at December 31, 2011	**13,021**	**139**	**225**	**344**	**13,729**
Carrying Value					
As at January 1, 2010	9,494	21	2,404	130	12,049
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**

[1] Includes office furniture, fixtures, leasehold improvements, information technology, aircraft and marine terminal facilities.

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of $125 million (2010 – $87 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 2011 (2010 – $nil).

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

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Development and production	**52**	42	64
Refining equipment	**125**	1,673	1,366
Other	**112**	45	4
	289	1,760	1,434

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 Statement of Earnings and Comprehensive Income.

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

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Development and Production	**2**	–	–
Refining Equipment	**45**	14	–
	47	14	–

The impairment losses during the year 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 have been reclassified as held for sale (Note 14). The natural gas assets reside in the Conventional segment. The 2010 impairment loss was related to a processing unit at the Borger Refinery which was determined to be a redundant asset.

17. DIVESTITURES

In 2011, the Company disposed of non-core oil and 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 oil and gas properties and corporate assets.

18. OTHER ASSETS

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Partner Loans	**–**	274	183
Long-term Receivables	**18**	7	7
Prepaids	**8**	–	–
Other	**18**	–	2
	44	281	192

19. GOODWILL

As at	December 31, 2011	December 31, 2010
Carrying Value, Beginning of Year	**1,132**	1,146
Divestitures	**–**	(14)
Impairment	**–**	–
Carrying Value, End of Year	**1,132**	1,132
Cost	**1,132**	1,132
Accumulated Impairment	**–**	–
Carrying Value, End of Year	**1,132**	1,132

There were no additions to goodwill during 2011 and 2010.

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, 2011	December 31, 2010	January 1, 2010
Suffield	**393**	393	393
Palliser	**–**	–	14
Foster Creek	**242**	242	242
Northern Alberta	**497**	497	497
	1,132	1,132	1,146

There was no impairment of goodwill in 2011 and 2010.

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	December 31, 2011	December 31, 2010	January 1, 2010
Accruals	**1,193**	852	545
Trade	**789**	471	509
Employee Long-Term Incentives	**209**	267	217
Interest	**72**	74	104
Other	**316**	179	230
	2,579	1,843	1,605

21. LONG-TERM DEBT

As at	Note	December 31, 2011	December 31, 2010	January 1, 2010
Canadian Dollar Denominated Debt				
Revolving term debt [1]	A	**–**	–	32
U.S. Dollar Denominated Debt				
Revolving term debt [1]	A	**–**	–	26
Unsecured notes (US$3,500)	B	**3,559**	3,481	3,663
		3,559	3,481	3,689
Total Debt Principal		**3,559**	3,481	3,721
Debt Discounts and Transaction Costs	C	**(32)**	(49)	(65)
Current Portion of Long-Term Debt	D	**–**	–	–
		3,527	3,432	3,656

[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, 2011 was 5.5 percent (2010 – 5.8 percent).

A) REVOLVING TERM DEBT

At December 31, 2011, Cenovus had in place a committed credit facility in the amount of $3,000 million or its equivalent amount in U.S. dollars. The committed credit facility matures on November 30, 2015 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, 2011, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2010 – $nil, January 1, 2010 – $58 million).

B) UNSECURED NOTES

Unsecured notes are comprised of the following senior unsecured notes:

	US$ Principal Amount	December 31, 2011	December 31, 2010	January 1, 2010
4.50% due September 15, 2014	**800**	**814**	796	837
5.70% due October 15, 2019	**1,300**	**1,322**	1,293	1,361
6.75% due November 15, 2039	**1,400**	**1,423**	1,392	1,465
	3,500	**3,559**	3,481	3,663

Cenovus has in place a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1,500 million. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2011, no medium term notes have been issued under this Canadian prospectus. The shelf prospectus expires in July 2012.

Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$1,500 million. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2011, no notes have been issued under this U.S. prospectus. The shelf prospectus expires in August 2012.

At December 31, 2011, the Company is in compliance with all of the terms of its debt agreements.

C) DEBT DISCOUNTS AND TRANSACTION COSTS

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are being amortized using the effective interest rate method. Transaction costs associated with the revolving term debt have been recorded as a prepayment and are being amortized over the remaining term of the committed credit facility. During 2011, additional transaction costs of $3 million were recorded (2010 – $nil).

D) MANDATORY DEBT PAYMENTS

	US$ Principal Amount	C$ Principal Amount	**Total C$ Equivalent**
2012	–	–	**–**
2013	–	–	**–**
2014	800	–	**814**
2015	–	–	**–**
2016	–	–	**–**
Thereafter	2,700	–	**2,745**
	3,500	–	**3,559**

22. DECOMMISSIONING LIABILITIES

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

As at	**December 31, 2011**	December 31, 2010
Decommissioning Liabilities, Beginning of Year	**1,399**	1,185
Liabilities incurred	**49**	44
Liabilities settled	**(56)**	(32)
Liabilities divested	**–**	(90)
Transfers and reclassifications	**(55)**	(5)
Change in estimated future cash flows	**146**	51
Change in discount rate	**218**	173
Unwinding of discount on decommissioning liabilities	**75**	75
Foreign currency translation	**1**	(2)
Decommissioning Liabilities, End of Year	**1,777**	1,399

The undiscounted amount of estimated cash flows required to settle the obligation is $6,541 million (December 31, 2010 – $6,093 million, January 1, 2010 – $5,683 million), which has been discounted using a credit-adjusted risk free rate of 4.8 percent (December 31, 2010 – 5.4 percent, January 1, 2010 – 6.0 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.

SENSITIVITIES

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

	2011		2010	
As at	**Credit-adjusted risk-free rate**	**Inflation rate**	Credit-adjusted risk-free rate	Inflation rate
One percent increase	**(367)**	**504**	(287)	398
One percent decrease	**494**	**(379)**	388	(278)

23. OTHER LIABILITIES

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Partner Loans	**–**	274	183
Deferred Revenue	**35**	37	40
Employee Long-Term Incentives	**55**	18	–
Pension and Other Post-Employment Benefits	**16**	13	19
Other	**22**	4	4
	128	346	246

24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

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

The Company files an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2010 and the next required actuarial valuation will be as at December 31, 2013.

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

	Pension Benefits		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Accrued Benefit Obligation, End of Year	**84**	68	56
Fair Value of Plan Assets, End of Year	**61**	59	54
Funded Status – Plan Assets (less) than Benefit Obligation	**(23)**	(9)	(2)
Amounts Not Recognized:			
Unamortized net actuarial (gain) loss	**22**	8	–
Unamortized past service cost	**–**	–	–
Accrued Benefit Asset (Liability)	**(1)**	(1)	(2)

	OPEB		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Accrued Benefit Obligation, End of Year	**19**	14	11
Fair Value of Plan Assets, End of Year	**–**	–	–
Funded Status – Plan Assets (less) than Benefit Obligation	**(19)**	(14)	(11)
Amounts Not Recognized:			
Unamortized net actuarial (gain) loss	**4**	2	–
Unamortized past service cost	**–**	–	–
Accrued Benefit Asset (Liability)	**(15)**	(12)	(11)

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

	Pension Benefits		OPEB	
For the years ended December 31,	**2011**	2010	**2011**	2010
Current Service Cost	**3**	3	**2**	1
Interest Cost	**4**	3	**1**	1
Expected Return on Plan Assets	**(4)**	(3)	**–**	–
Actuarial Gains (Losses)	**1**	–	**–**	–
Past Service Cost	**–**	–	**–**	–
Effect of Curtailment/Settlement	**–**	–	**–**	–
Plan Cost	**4**	3	**3**	2
Defined Contribution Plans Cost	**22**	18	**–**	–
Net Benefit Plan Cost	**26**	21	**3**	2

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

	Pension Benefits			OPEB		
As at	**December 31, 2011**	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Discount Rate	**4.25%**	5.25%	6.00%	**4.25%**	5.25%	6.00%
Rate of Compensation Increase	**3.99%**	4.05%	4.05%	**5.77%**	5.65%	5.77%

The expected future benefits payments for the year ended December 31, 2012 is $2 million for the defined benefit plan and $nil for the OPEB.

25. SHARE CAPITAL

AUTHORIZED

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. 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.

ISSUED AND OUTSTANDING

	2011		2010	
As at December 31,	**Number of Common Shares** *(thousands)*	**Amount**	Number of Common Shares *(thousands)*	Amount
Outstanding, Beginning of Year	**752,675**	**3,716**	751,309	3,681
Common Shares Issued under Stock Option Plans	**1,824**	**64**	1,366	35
Outstanding, End of Year	**754,499**	**3,780**	752,675	3,716

There were no Preferred Shares outstanding as at December 31, 2011 (2010 – nil).

At December 31, 2011, there were 30 million (2010 – 26 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.

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 January 1, 2010 and December 31, 2010	4,083	–	4,083
Stock-based compensation expense	–	24	24
As at December 31, 2011	**4,083**	**24**	**4,107**

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, 2011	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**	**1.35**	**31.97**	**18.89**	**10,411**
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	**5**	**1.38**	**28.96**	**33.83**	**9,686**
TSARs	Prior to February 17, 2010	**5**	**1.45**	**28.95**	**33.83**	**9,395**
TSARs	On or After February 17, 2010	**7**	**5.20**	**26.72**	**33.83**	**5,526**
NSRs	On or After February 24, 2011	**7**	**6.24**	**36.95**	**33.83**	**5,809**

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, 2011 was $8.27 before considering forfeitures. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**2.46%**
Expected Dividend Yield	**2.16%**
Expected Volatility [1]	**28.81%**
Expected Life *(Years)*	**4.55**

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The following tables summarize the information related to the NSRs as at December 31, 2011:

As at December 31, 2011 (thousands of units)	NSRs	Weighted Average Exercise Price *($)*
Outstanding, Beginning of Year	**–**	**–**
Granted	**5,931**	**36.96**
Exercised as options for common shares	**–**	**–**
Forfeited	**(122)**	**37.50**
Outstanding, End of Year	**5,809**	**36.95**
Exercisable, End of Year	**1**	**37.54**

	Outstanding NSRs *(thousands of units)*		
Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life *(Years)*	Weighted Average Exercise Price *($)*
30.00 to 39.99	**5,809**	**6.24**	**36.95**
	5,809	**6.24**	**36.95**

	Exercisable NSRs (thousands of units)	
Range of Exercise Price ($)	**NSRs**	**Weighted Average Exercise Price ($)**
30.00 to 39.99	**1**	**37.54**
	1	**37.54**

TSARS HELD BY CENOVUS EMPLOYEES

The Company has recorded a liability of $90 million at December 31, 2011 (December 31, 2010 – $87 million, January 1, 2010 – $43 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:

	2011
Risk Free Interest Rate	**1.10%**
Expected Dividend Yield	**2.36%**
Expected Volatility [1]	**31.95%**
Cenovus's Common Share Price	**$33.83**

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2011 was $43 million (December 31, 2010 – $42 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Exercise Price ($)**
Outstanding, Beginning of Year	12,044	7,073	**19,117**	**27.75**
Granted	138	–	**138**	**33.40**
Exercised for cash payment	(1,274)	(641)	**(1,915)**	**26.31**
Exercised as options for common shares	(1,202)	(564)	**(1,766)**	**26.38**
Forfeited	(315)	(338)	**(653)**	**28.37**
Outstanding, End of Year	**9,391**	**5,530**	**14,921**	**28.12**
Exercisable, End of Year	**4,618**	**4,256**	**8,874**	**29.15**

The weighted average market price of Cenovus's common shares at the date of exercise during the year ended December 31, 2011 was $35.71.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Remaining Contractual Life (Years)**	**Weighted Average Exercise Price ($)**
20.00 to 29.99	7,617	3,578	**11,195**	**3.32**	**26.43**
30.00 to 39.99	1,711	1,952	**3,663**	**1.40**	**33.03**
40.00 to 49.99	63	–	**63**	**1.45**	**43.30**
	9,391	**5,530**	**14,921**	**2.84**	**28.12**

Range of Exercise Price ($)	Exercisable TSARs *(thousands of units)* TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	3,029	2,304	**5,333**	**26.45**
30.00 to 39.99	1,526	1,952	**3,478**	**33.04**
40.00 to 49.99	63	–	**63**	**43.30**
	4,618	**4,256**	**8,874**	**29.15**

The market price of Cenovus common shares at December 31, 2011 was $33.83.

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, 2011 (December 31, 2010 – $24 million, January 1, 2010 – $70 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:

	2011
Risk Free Interest Rate	**0.99%**
Expected Dividend Yield	**4.31%**
Expected Volatility [(1)]	**28.04%**
Encana's Common Share Price	**$18.89**

(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, 2011 was $nil (December 31, 2010 – $6 million).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	6,429	7,098	**13,527**	**31.17**
Exercised for cash payment	(1,824)	(451)	**(2,275)**	**26.97**
Exercised as options for Encana common shares	(16)	–	**(16)**	**25.71**
Forfeited	(308)	(517)	**(825)**	**32.72**
Outstanding, End of Year	**4,281**	**6,130**	**10,411**	**31.97**
Exercisable, End of Year	**3,605**	**4,856**	**8,461**	**32.64**

The weighted average market price of Encana's common shares at the date of exercise during the year ended December 31, 2011 was $31.95.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Remaining Contractual Life** *(Years)*	**Weighted Average Exercise Price** *($)*
20.00 to 29.99	2,437	4,014	**6,451**	**1.48**	**29.15**
30.00 to 39.99	1,711	2,116	**3,827**	**1.12**	**36.26**
40.00 to 49.99	131	–	**131**	**1.48**	**44.86**
50.00 to 59.99	2	–	**2**	**1.39**	**50.39**
	4,281	**6,130**	**10,411**	**1.35**	**31.97**

	Exercisable TSARs (thousands of units)			
Range of Exercise Price ($)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Exercise Price** *($)*
20.00 to 29.99	1,778	2,740	**4,518**	**29.20**
30.00 to 39.99	1,694	2,116	**3,810**	**36.28**
40.00 to 49.99	131	–	**131**	**44.86**
50.00 to 59.99	2	–	**2**	**50.39**
	3,605	**4,856**	**8,461**	**32.64**

The market price of Encana common shares at December 31, 2011 was $18.89.

CENOVUS REPLACEMENT TSARS HELD BY ENCANA EMPLOYEES

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

The Company has recorded a liability of $83 million at December 31, 2011 (December 31, 2010 – $123 million, January 1, 2010 – $84 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:

	2011
Risk Free Interest Rate	**0.99%**
Expected Dividend Yield	**2.36%**
Expected Volatility [1]	**31.95%**
Cenovus's Common Share Price	**$33.83**

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at December 31, 2011 was $32 million (December 31, 2010 – $60 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,214	8,940	**17,154**	**28.16**
Exercised for cash payment	(4,082)	(2,758)	**(6,840)**	**27.00**
Exercised as options for common shares	(55)	(3)	**(58)**	**23.29**
Forfeited	(142)	(428)	**(570)**	**29.14**
Outstanding, End of Year	**3,935**	**5,751**	**9,686**	**28.96**
Exercisable, End of Year	**3,203**	**4,319**	**7,522**	**29.73**

The weighted average market price of Cenovus's common shares at the date of exercise during the year ended December 31, 2011 was $35.80.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	2,197	3,807	**6,004**	**1.55**	**26.41**
30.00 to 39.99	1,671	1,944	**3,615**	**1.11**	**32.95**
40.00 to 49.99	67	–	**67**	**1.44**	**42.88**
	3,935	**5,751**	**9,686**	**1.38**	**28.96**

	Exercisable TSARs (thousands of units)			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	1,465	2,375	**3,840**	**26.48**
30.00 to 39.99	1,671	1,944	**3,615**	**32.95**
40.00 to 49.99	67	–	**67**	**42.88**
	3,203	**4,319**	**7,522**	**29.73**

The market price of Cenovus common shares at December 31, 2011 was $33.83.

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. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $55 million at December 31, 2011 (December 31, 2010 – $18 million, January 1, 2010 – $nil) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2011. The intrinsic value of vested PSUs was $nil at December 31, 2011 and 2010 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, 2011:

(thousands of units)	**PSUs**
Outstanding, Beginning of Year	**1,252**
Granted	**1,409**
Cancelled	**(98)**
Units in Lieu of Dividends	**60**
Outstanding, End of Year	**2,623**

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 $35 million at December 31, 2011 (December 31, 2010 – $31 million, January 1, 2010 – $20 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2011. 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, 2011:

(thousands of units)	**DSUs**
Outstanding, Beginning of Year	**940**
Granted to Directors	**65**
Granted from Annual Bonus Awards	**17**
Units in Lieu of Dividends	**23**
Exercised	**(3)**
Outstanding, End of Year	**1,042**

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,	**2011**	2010
NSRs	**16**	–
TSARs held by Cenovus employees	**24**	45
Encana Replacement TSARs held by Cenovus employees	**(8)**	(20)
PSUs	**27**	13
DSUs	**4**	9
Total stock-based compensation expense (recovery)	**63**	47

27. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2011**	2010
Salaries, Bonuses and Other Short-Term Employee Benefits	**399**	348
Defined Contribution Pension Plan	**13**	11
Defined Benefit Pension Plan and OPEB	**4**	(1)
Stock-Based Compensation (Note 26)	**63**	47
	479	405

28. RELATED PARTY TRANSACTIONS

KEY MANAGEMENT COMPENSATION

Key management includes Directors (executive and non-executive), the 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,	**2011**	2010
Salaries, Director Fees and Short-Term Benefits	**25**	22
Post-Employment Benefits	**3**	2
Other Long-Term Benefits	**–**	–
Stock-Based Compensation	**35**	37
Total	**63**	61

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs associated with stock options, NSRs, TSARs, PSUs and DSUs recognized during the year.

29. INTEREST IN JOINT OPERATIONS

Cenovus has a 50 percent interest in FCCL Partnership, a jointly controlled entity which is involved in the development and production of crude oil. In addition, through its interest in the general partner and a limited partner, Cenovus has a 50 percent interest in WRB Refining LP, a jointly controlled entity, which owns two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products.

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Summarized financial statement information for these jointly controlled entities is as follows:

Consolidated Statements of Earnings For the years ended December 31,	FCCL Partnership [1] **2011**	2010	WRB Refining LP [1] **2011**	2010
Revenues	**2,364**	1,829	**8,672**	6,624
Expenses				
Purchased product	**–**	–	**7,223**	6,095
Operating, transportation and blending and realized gain/loss on risk management	**1,397**	1,074	**473**	462
Operating Cash Flow	**967**	755	**976**	67
Depreciation, depletion and amortization	**205**	210	**130**	86
Other expenses (income)	**(136)**	20	**(4)**	13
Net Earnings (Loss)	**898**	525	**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.

Consolidated Balance Sheets as at	FCCL Partnership **December 31, 2011**	December 31, 2010	January 1, 2010	WRB Refining LP **December 31, 2011**	December 31, 2010	January 1, 2010
Current Assets	**937**	703	800	**1,402**	951	812
Long-term Assets	**6,864**	6,419	6,374	**3,188**	2,840	2,391
Current Liabilities	**317**	229	147	**759**	559	515
Long-term Liabilities	**83**	40	29	**73**	327	407

Capital commitments through jointly controlled entities are as follows:

2011	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Capital Commitments	179	58	11	2	3	–	**253**

2010	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Capital Commitments	147	10	3	3	–	–	**163**

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 includes the Company's short-term borrowings plus long-term debt, including the current portion. 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 financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as 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 continues to target a Debt to Capitalization ratio of between 30 and 40 percent.

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Short-Term Borrowings	**–**	–	–
Long-Term Debt	**3,527**	3,432	3,656
Debt	**3,527**	3,432	3,656
Shareholders' Equity	**9,406**	8,395	7,809
Total Capitalization	**12,933**	11,827	11,465
Debt to Capitalization	**27%**	29%	32%

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

As at	**December 31, 2011**	December 31, 2010
Debt	**3,527**	3,432
Net Earnings	**1,478**	1,081
Add (deduct):		
Finance costs	**447**	498
Interest income	**(124)**	(144)
Income tax expense	**729**	223
Depreciation, depletion and amortization	**1,295**	1,302
Exploration expense	**–**	–
Unrealized (gain) loss on risk management	**(180)**	(46)
Foreign exchange (gain) loss, net	**26**	(51)
(Gain) loss on divestiture of assets	**(107)**	(116)
Other (income) loss, net	**4**	(13)
Adjusted EBITDA	**3,568**	2,734
Debt to Adjusted EBITDA	**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 the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, Cenovus changed its definition of Adjusted EBITDA to exclude unrealized gains and losses on risk management activities. The Adjusted EBITDA and the ratio of Debt to Adjusted EBITDA for prior periods have been re-presented in a consistent manner. As noted above, Cenovus's capital structure objectives and targets remain unchanged from previous periods. At December 31, 2011, 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, long-term debt and obligations for stock-based compensation carried at fair value. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable, 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.

	December 31, 2011		December 31, 2010		January 1, 2010	
As at	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets						
Held-For-Trading:						
Risk management assets	**284**	**284**	206	206	61	61
Loans and Receivables:						
Cash and cash equivalents	**495**	**495**	300	300	155	155
Accounts receivable and accrued liabilities	**1,405**	**1,405**	1,059	1,059	982	982
Partnership contribution receivable	**2,194**	**2,194**	2,491	2,491	2,966	2,966
Other	**29**	**29**	–	–	–	–
Financial Liabilities						
Held-For-Trading:						
Risk management liabilities	**68**	**68**	173	173	74	74
Financial Liabilities Measured at Amortized Cost:						
Accounts payable and accrued liabilities	**2,579**	**2,579**	1,843	1,843	1,605	1,605
Short-term borrowings	**–**	**–**	–	–	–	–
Long-term debt	**3,527**	**4,316**	3,432	3,940	3,656	3,964
Partnership contribution payable	**2,225**	**2,225**	2,519	2,519	2,990	2,990
Other	**17**	**17**	–	–	–	–

B) RISK MANAGEMENT ASSETS AND LIABILITIES

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

NET RISK MANAGEMENT POSITION

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Risk Management Assets			
Current asset	**232**	163	60
Long-term asset	**52**	43	1
	284	206	61
Risk Management Liabilities			
Current liability	**54**	163	70
Long-term liability	**14**	10	4
	68	173	74
Net Risk Management Asset (Liability) [1]	**216**	33	(13)

[1] Of the $216 million net risk management asset balance at December 31, 2011, a liability of $3 million relates to the contract with Encana (2010 – net asset of $41 million).

SUMMARY OF UNREALIZED RISK MANAGEMENT POSITIONS

	December 31, 2011			December 31, 2010			January 1, 2010		
	Risk Management			Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices									
Crude Oil	**22**	**65**	**(43)**	4	159	(155)	8	66	(58)
Natural Gas	**247**	**3**	**244**	202	–	202	53	–	53
Power	**15**	**–**	**15**	–	14	(14)	–	8	(8)
Total Fair Value	**284**	**68**	**216**	206	173	33	61	74	(13)

NET FAIR VALUE METHODOLOGIES USED TO CALCULATE UNREALIZED RISK MANAGEMENT POSITIONS

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Prices actively quoted	**226**	40	6
Prices sourced from observable data or market corroboration	**(10)**	(7)	(19)
Total Fair Value	**216**	33	(13)

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

NET FAIR VALUE OF COMMODITY PRICE POSITIONS

As at December 31, 2011	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,800 bbls/d	2012	US$98.72/bbl	**(1)**
WTI NYMEX Fixed Price	24,500 bbls/d	2012	$99.47/bbl	**(12)**
Other Fixed Price Contracts [1]		2012-2013		**(22)**
Other Financial Positions [2]				**(8)**
Crude Oil Fair Value Position				**(43)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**131**
AECO Fixed Price [1]	127 MMcf/d	2012	$4.50/Mcf	**73**
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	**43**
Other Fixed Price Contracts [1]		2012-2013		**(3)**
Natural Gas Fair Value Position				**244**
Power Purchase Contracts				
Power Fair Value Position				**15**

[1] Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada, various sales points and quality differentials.

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

EARNINGS IMPACT OF REALIZED AND UNREALIZED GAINS (LOSSES) ON RISK MANAGEMENT POSITIONS

For the years ended December 31,	**2011**	2010
Realized Gain (Loss) [1]		
Crude Oil	**(135)**	(17)
Natural Gas	**210**	289
Refining	**(14)**	10
Power	**7**	(4)
	68	278
Unrealized Gain (Loss) [2]		
Crude Oil	**106**	(92)
Natural Gas	**38**	152
Refining	**7**	(8)
Power	**29**	(6)
	180	46
Gain (Loss) on Risk Management	**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,

	2011		2010
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**33**		
Change in fair value of contracts in place at beginning of year and contracts entered into during the year	**248**	**248**	324
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	**3**	**–**	–
Fair value of contracts realized during the year	**(68)**	**(68)**	(278)
Fair Value of Contracts, End of Year	**216**	**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. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

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 natural gas hedges	**(160)**	**160**
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	**2**	**(2)**
Power commodity price	± $25 per MWHr applied to power hedge	**19**	**(19)**

Risk Management Positions in Place as at December 31, 2010

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$10 per bbl applied to WTI hedges	(251)	251
Crude oil differential price	± US$5 per bbl applied to differential hedges tied to production	7	(7)
Natural gas commodity price	± $1 per mcf applied to NYMEX and AECO natural gas hedges	(218)	218
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	2	(2)
Power commodity price	± $25 per MWHr applied to power hedge	38	(38)

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. To help protect against widening crude oil price differentials, Cenovus has entered into a limited number of swaps and futures to manage the price differentials.

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

Power – The Company has in place 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 or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2011, over 92 percent (2010 – 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2011, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (2010 – two counterparties) 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 current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

LIQUIDITY RISK

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 30, 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, 2011, Cenovus's committed credit facility was fully available. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1,500 million and a U.S. debt shelf prospectus for US$1,500 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

Undiscounted cash outflows relating to financial liabilities are outlined in the table below:

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.

2010	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	1,843	–	–	–	1,843
Risk Management Liabilities	163	10	–	–	173
Long-Term Debt [(1)]	203	407	1,167	5,236	7,013
Partnership Contribution Payable [(1)]	486	972	972	609	3,039
Partner Loans Payable	–	274	–	–	274

(1) Principal and interest, including current portion.

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, 2011, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million at December 31, 2010) and US$2,157 million related to the U.S. dollar Partnership Contribution Receivable (US$2,505 million at December 31, 2010). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $13 million change in foreign exchange (gain) loss at December 31, 2011 (2010 – $10 million).

INTEREST RATE RISK

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

At December 31, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2010 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

32. SUPPLEMENTARY INFORMATION

SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2011**	2010
Interest Paid	**357**	423
Income Taxes Paid	**–**	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:

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**
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 by the Company on behalf of FCCL Partnership are reflected at Cenovus's 50 percent interest.

2010	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Pipeline Transportation [1]	107	93	167	167	166	953	1,653
Operating Leases (Building Leases)	33	87	88	85	78	1,553	1,924
Product Purchases	23	18	18	18	18	7	102
Capital Commitments [2]	248	94	16	14	11	37	420
Other Long-Term Commitments	4	2	1	1	–	1	9
Total Payments [3]	415	294	290	285	273	2,551	4,108
Product Sales	50	52	54	56	57	63	332

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Includes those commitments related to jointly controlled entities.
(3) Contracts undertaken by the Company on behalf of FCCL Partnership are reflected at Cenovus's 50 percent interest.

At December 31, 2011, there were outstanding letters of credit aggregating $17 million issued as security for performance under certain contracts (2010 – $23 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 related to its oil and gas properties, refining facilities and midstream facilities at the end of their useful lives. Cenovus has recognized a liability of $1,777 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

INCOME TAX MATTERS

The 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. FIRST TIME ADOPTION OF IFRS

TRANSITION TO IFRS

These Consolidated Financial Statements for the year ended December 31, 2011 represent the Company's first annual consolidated financial statements prepared in accordance with IFRS, which are also generally accepted accounting principles for publicly accountable enterprises in Canada. The Company adopted IFRS in accordance with IFRS 1, *"First-time Adoption of International Financial Reporting Standards"* and has prepared its Consolidated Financial Statements with IFRS applicable for periods beginning on or after January 1, 2010, using significant accounting policies as described in Note 3. For all periods up to and including the year ended December 31, 2010, the Company prepared its Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). As allowed by IFRS 1, the Company has chosen not to include the comparative financial information for the year ended December 31, 2009. This note explains the principal adjustments made by the Company to restate its previous GAAP Consolidated Financial Statements on transition to IFRS.

EXEMPTIONS APPLIED UNDER IFRS 1

On first-time adoption of IFRS, the general principle is that an entity retrospectively restates its results for all standards in force at the first reporting date. However, IFRS 1 provides certain exemptions from the general requirements of IFRS to assist with the transition process. Cenovus has applied the following exemptions in the preparation of its opening Balance Sheet dated January 1, 2010 (the "Transition Date"):

- Fair Value as Deemed Cost – The Company has elected to measure its Refining assets at their fair values at the Transition Date and use those fair values as their deemed cost at that date (Note A).
- Deemed Cost Election for Oil and Gas Assets – Under previous GAAP, Cenovus accounted for its oil and gas properties in one cost centre using full cost accounting. The Company has elected to measure its oil and gas properties at the Transition Date on the following basis:
  a) exploration and evaluation assets at the amount determined under the Company's previous GAAP; and
  b) the remainder allocated to the underlying property, plant and equipment assets on a pro rata basis using proved reserve values discounted at 10 percent at the Transition Date (Note B).
- Leases – Cenovus has elected to assess lease arrangements using the facts and circumstances as of the Transition Date under International Financial Reporting Interpretations Committee Interpretation 4, *"Determining whether an Arrangement contains a Lease"* ("IFRIC 4").
- Employee Benefits – The Company has elected not to apply IAS 19, *"Employee Benefits"* retrospectively and as such all cumulative actuarial gains and losses on the Company's defined benefit plans were recognized at the Transition Date (Note F).
- Business Combinations – IFRS 3, *"Business Combinations"* has not been applied to business combinations that occurred before the Transition Date.
- Cumulative Currency Translation Differences – Cumulative currency translation differences for all foreign operations are deemed to be zero at the Transition Date (Note J).
- Decommissioning Liabilities – Cenovus applied the deemed cost election for oil and gas assets under IFRS 1 and as such decommissioning liabilities at the date of transition have been measured in accordance with IAS 37, *"Provisions, Contingent Liabilities and Contingent Assets"* (Note D).
- Borrowing Costs – In accordance with IFRS 1, the Company has elected to apply IAS 23, *"Borrowing Costs"* to qualifying assets for which the commencement date for capitalization of borrowing costs occurred on or after the Transition Date. Borrowing costs have not been capitalized on qualifying assets under construction on or before the Transition Date.
- Estimates – Hindsight was not used to create or revise estimates and accordingly, the estimates made by the Company under previous GAAP are consistent with their application under IFRS.

Under IFRS 1, the opening Balance Sheet adjustments are recorded directly to retained earnings, or if appropriate, another category of equity. As Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana into two independent energy companies, Encana and Cenovus, all opening Balance Sheet adjustments have been recorded to paid in surplus. The impacts of applying the above noted IFRS 1 exemptions and the accounting policy differences between previous GAAP and IFRS are summarized in the following tables:

RECONCILIATION OF STATEMENT OF EARNINGS AND COMPREHENSIVE INCOME

For the year ended December 31, 2010	Notes	Previous GAAP	Adjustments	**IFRS**
Revenues				
Gross Sales	K	13,422	(332)	**13,090**
Less: Royalties		449	–	**449**
		12,973	(332)	**12,641**
Expenses				
Purchased product	K	7,549	2	**7,551**
Transportation and blending		1,065	–	**1,065**
Operating	E,F,K	1,302	(16)	**1,286**
Production and mineral taxes		34	–	**34**
(Gain) loss on risk management	K	–	(324)	**(324)**
Depreciation, depletion and amortization	A,B,C	1,310	(8)	**1,302**
Exploration expense	H	–	3	**3**
General and administrative	E,F	251	(5)	**246**
Finance costs	K	–	498	**498**
Interest, net	K	279	(279)	**–**
Interest income	K	–	(144)	**(144)**
Accretion of asset retirement obligation	K	75	(75)	**–**
Foreign exchange (gain) loss, net		(51)	–	**(51)**
(Gain) loss on divestiture of assets	G	9	(125)	**(116)**
Other (income) loss, net		(13)	–	**(13)**
Earnings Before Income Tax		1,163	141	**1,304**
Income tax expense	I	170	53	**223**
Net Earnings		993	88	**1,081**
Other Comprehensive Income (Loss), Net of Tax				
Foreign currency translation adjustment	J	(13)	84	**71**
Comprehensive Income (Loss)		980	172	**1,152**
Net Earnings per Common Share				
Basic	L	1.32	0.12	**1.44**
Diluted	L	1.32	0.11	**1.43**

RECONCILIATION OF THE BALANCE SHEET

		December 31, 2010			January 1, 2010		
As at	Notes	Previous GAAP	Adjustments	**IFRS**	Previous GAAP	Adjustments	**IFRS**
Assets							
Current Assets							
Cash and cash equivalents		300	–	**300**	155	–	**155**
Accounts receivable and accrued revenues	E	1,055	4	**1,059**	978	4	**982**
Income tax receivable		31	–	**31**	40	–	**40**
Current portion of Partnership Contribution Receivable		346	–	**346**	345	–	**345**
Inventories		880	–	**880**	875	–	**875**
Risk management		163	–	**163**	60	–	**60**
Assets held for sale	K	–	65	**65**	–	–	**–**
Current Assets		2,775	69	**2,844**	2,453	4	**2,457**
Assets Held for Sale	K	65	(65)	**–**	–	–	**–**
Exploration and Evaluation Assets	K	–	713	**713**	–	580	**580**
Property, Plant and Equipment, net	A,B,D, E,F,G, H,J,K	15,530	(2,903)	**12,627**	15,214	(3,165)	**12,049**
Partnership Contribution Receivable		2,145	–	**2,145**	2,621	–	**2,621**
Risk Management		43	–	**43**	1	–	**1**
Other Assets	C,F,J	391	(110)	**281**	320	(128)	**192**
Deferred Income Tax	K	–	55	**55**	–	3	**3**
Goodwill	G	1,146	(14)	**1,132**	1,146	–	**1,146**
Total Assets		22,095	(2,255)	**19,840**	21,755	(2,706)	**19,049**
Liabilities and Shareholders' Equity							
Current Liabilities							
Accounts payable and accrued liabilities	E	1,825	18	**1,843**	1,574	31	**1,605**
Income tax payable		154	–	**154**	–	–	**–**
Current portion of Partnership Contribution Payable		343	–	**343**	340	–	**340**
Risk management		163	–	**163**	70	–	**70**
Liabilities related to assets held for sale	K	–	7	**7**	–	–	**–**
Current Liabilities		2,485	25	**2,510**	1,984	31	**2,015**
Liabilities Related to Assets Held for Sale	K	7	(7)	**–**	–	–	**–**
Long-Term Debt		3,432	–	**3,432**	3,656	–	**3,656**
Partnership Contribution Payable		2,176	–	**2,176**	2,650	–	**2,650**
Risk Management		10	–	**10**	4	–	**4**
Decommissioning Liabilities	D,G	1,213	186	**1,399**	1,147	38	**1,185**
Other Liabilities	F	346	–	**346**	239	7	**246**
Deferred Income Tax	I,J,K	2,404	(832)	**1,572**	2,467	(983)	**1,484**
Total Liabilities		12,073	(628)	**11,445**	12,147	(907)	**11,240**
Share Capital		3,716	–	**3,716**	3,681	–	**3,681**
Paid in Surplus	A,C,D, E,F,I,J	5,896	(1,813)	**4,083**	5,896	(1,813)	**4,083**
Accumulated Other Comprehensive Income (Loss)	J	(27)	98	**71**	(14)	14	**–**
Retained Earnings		437	88	**525**	45	–	**45**
Shareholders' Equity		10,022	(1,627)	**8,395**	9,608	(1,799)	**7,809**
Total Liabilities and Shareholders' Equity		22,095	(2,255)	**19,840**	21,755	(2,706)	**19,049**

RECONCILIATION OF THE STATEMENT OF CASH FLOWS

For the year ended December 31, 2010	Notes	Previous GAAP	Adjustments	IFRS
Operating Activities				
Net earnings		993	88	**1,081**
Depreciation, depletion and amortization	A,B,C	1,310	(8)	**1,302**
Deferred income taxes	I	88	53	**141**
Unrealized (gain) loss on risk management		(46)	–	**(46)**
Unrealized foreign exchange (gain) loss		(69)	–	**(69)**
(Gain) loss on divestitures of assets	G	9	(125)	**(116)**
Unwinding of discount on decommissioning liabilities		75	–	**75**
Other		55	(11)	**44**
		2,415	(3)	**2,412**
Net change in other assets and liabilities		(55)	–	**(55)**
Net change in non-cash working capital		234	–	**234**
Cash From Operating Activities		2,594	(3)	**2,591**
Investing Activities				
Capital expenditures – exploration and evaluation assets		–	(350)	**(350)**
Capital expenditures – property, plant and equipment		(2,208)	357	**(1,851)**
Proceeds from divestitures of assets		309	–	**309**
Net change in investments and other		4	–	**4**
Net change in non-cash working capital	E	99	(4)	**95**
Cash From (Used in) Investing Activities		(1,796)	3	**(1,793)**
Net Cash Provided (Used) before Financing Activities		798	–	**798**
Cash From (Used in) Financing Activities		(631)	–	**(631)**
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		(22)	–	**(22)**
Increase (Decrease) in Cash and Cash Equivalents		145	–	**145**
Cash and Cash Equivalents, Beginning of Year		155	–	**155**
Cash and Cash Equivalents, End of Year		300	–	**300**

Notes:

A) REFINING PROPERTY, PLANT AND EQUIPMENT

At January 1, 2010, Cenovus elected to measure its refining assets at fair value and to use that fair value as its deemed cost on transition to IFRS. The fair value of the refining assets was determined to be US$4,543 million, US$2,272 million net to Cenovus, which resulted in the carrying value of the refining assets exceeding the fair value. Cenovus's carrying value of property, plant and equipment was reduced by C$2,585 million at the Transition Date with a corresponding reduction in paid in surplus.

In December 2010, it was determined that a processing unit at the Borger Refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, under previous GAAP, an impairment of $37 million was recorded. Under IFRS, the impairment was only $14 million due to the IFRS 1 election noted above to use the fair value as deemed cost. Therefore DD&A expense under IFRS was reduced by $23 million.

The lower carrying value under IFRS and the impairment adjustment noted above resulted in lower DD&A expense of $126 million for the year ended December 31, 2010.

B) OIL AND GAS PROPERTY, PLANT AND EQUIPMENT

Under previous GAAP, costs accumulated within each cost centre for oil and gas properties were depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on a country-by-country cost centre basis (full cost accounting). Under IFRS, 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 on an area-by-area basis. This resulted in an increase of $135 million in DD&A expense for the year ended December 31, 2010.

C) IMPAIRMENT OF DEFERRED ASSET

Under previous GAAP, other assets included a deferred asset, which represented the disproportionate interest received in 2007 and 2008 (15 percent in 2007 and 35 percent in 2008) that arose from the acquisition of the Borger Refinery in 2007. On transition to IFRS, it was determined that as a result of the reduction in the carrying value of the refineries due to the fair value election, the deferred asset was impaired and therefore was written off. Paid in surplus was decreased by the carrying value of the asset under previous GAAP of $121 million. Under previous GAAP, the deferred asset was being amortized over 10 years. As such, DD&A expense under IFRS decreased by $17 million for the year ended December 31, 2010.

D) DECOMMISSIONING LIABILITIES

As discussed above, the Company elected to apply the exemption to measure decommissioning liabilities at the Transition Date in accordance with IAS 37. As such, the Company re-measured the decommissioning liabilities as at the Transition Date using the period end credit-adjusted risk-free discount rate and recognized an increase of $38 million to the decommissioning liability.

Consistent with IFRS, decommissioning liabilities under previous GAAP were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition. However, under IFRS, estimated cash flows are discounted using the credit-adjusted risk-free rate that exists at the balance sheet date. As at December 31, 2010, property, plant and equipment and the decommissioning liability increased $154 million under IFRS. There was minimal impact to the unwinding of the discount for the year ended December 31, 2010.

E) STOCK-BASED COMPENSATION

Under previous GAAP, obligations for payments under Cenovus's stock option plan (with associated tandem stock appreciation rights) were accrued for using the intrinsic method. Under IFRS, these obligations are accrued for using the fair value method. As a result of the re-measurement of the liability as at January 1, 2010 a charge of $27 million was recognized in paid in surplus with an increase to accounts payable and accrued liabilities of $31 million and an increase to accounts receivable and accrued revenue of $4 million. For the year ended December 31, 2010, due to the differences in the measurement basis under IFRS, operating and general and administrative expense decreased $5 million and $4 million, respectively, property, plant and equipment decreased $4 million and accounts payable and accrued liabilities decreased $13 million.

F) EMPLOYEE BENEFITS

Cenovus elected under IFRS 1 to recognize all unamortized actuarial gains and losses on the defined benefit pension and other post-employment benefits plans at the Transition Date resulting, in a $7 million increase to other liabilities, a $7 million decrease to other assets and a $14 million charge to paid in surplus. Under previous GAAP, the actuarial losses continued to be amortized and, as such, for the year ended December 31, 2010, both operating and general and administrative expense decreased by $1 million. In addition, due to the recognition of all unamortized actuarial gains and losses at the Transition date, it was necessary to reclassify the pension asset to a pension liability resulting in a reclassification from other assets to other liabilities of $4 million at December 31, 2010.

G) GAINS/LOSSES ON DIVESTITURE OF ASSETS

Under previous GAAP, proceeds on the divestiture of oil and gas properties were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20 percent or more. Under IFRS, all gains and losses are recognized on oil and gas property divestitures and calculated as the difference between net proceeds and the carrying value of the net assets disposed. Accordingly, a gain of $125 million was recognized for the year ended December 31, 2010 under IFRS. At December 31, 2010 the carrying value of property, plant and equipment increased $133 million and goodwill and decommissioning liabilities were reduced by $14 million and $6 million, respectively.

H) PRE-EXPLORATION EXPENSE

Under IFRS, costs incurred prior to obtaining the legal right to explore must be expensed whereas under previous GAAP these costs were capitalized in the full cost pool. For the year ended December 31, 2010, $3 million of pre-exploration costs were expensed under IFRS. The accounting policy difference has resulted in a $3 million decrease to property, plant and equipment and a corresponding increase in exploration expense. This adjustment has decreased cash from operating activities by $3 million and increased cash from investing activities by a corresponding amount for the year ended December 31, 2010.

I) DEFERRED INCOME TAXES

The increase in paid in surplus of $986 million at the Transition Date related to deferred income taxes reflects the change in temporary differences resulting from the IFRS 1 exemptions applied. For the year ended December 31, 2010 deferred income tax increased by $53 million to reflect the changes in temporary differences resulting from the IFRS adjustments described above and a $9 million adjustment to recognize the deferred tax benefit on an intercompany transfer of oil and gas properties.

J) CURRENCY TRANSLATION ADJUSTMENTS

In accordance with IFRS 1, Cenovus elected to deem all cumulative currency translation differences for all foreign operations to be zero at the Transition Date. All foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date were transferred to paid in surplus.

In addition, AOCI is affected by the revaluation of the adjustments noted above that reside in a foreign operation notably the reduction in the carrying value of the Refining property, plant and equipment, the impairment of the deferred asset and the associated deferred income tax payable. The table below identifies the cumulative balance sheet impact at December 31, 2010 and January 1, 2010:

Increase (Decrease)	December 31, 2010	January 1, 2010
Assets		
Refining property, plant and equipment	125	–
Other assets	5	–
Liabilities and Equity		
Deferred income tax liability	46	–
Accumulated other comprehensive income	98	14
Paid in surplus	(14)	(14)

K) RECLASSIFICATIONS

EXPLORATION AND EVALUATION ("E&E") ASSETS

Under previous GAAP, E&E assets were included in property, plant and equipment, whereas under IFRS E&E assets are separately disclosed. The Company reclassified $580 million and $713 million from property, plant and equipment to E&E assets at January 1, 2010 and December 31, 2010, respectively.

FINANCE COSTS AND INTEREST INCOME

In addition, under previous GAAP, the unwinding of the discount on decommissioning liabilities was classified as accretion expense in the Consolidated Statements of Earnings and Comprehensive Income. Under IFRS this amount has been reclassified to finance costs.

Under previous GAAP, interest was reported on a net basis. Under IFRS interest expense is included in finance costs and interest income is reported separately.

GAINS/LOSSES ON RISK MANAGEMENT

Under previous GAAP, gains and losses from crude oil and natural gas commodity price risk management activities were recorded in gross revenues. Under IFRS, these activities do not meet the definition of revenue and therefore have been reclassified to (gain) loss on risk management in the Consolidated Statements of Earnings and Comprehensive Income. In addition, risk management activities related to power and the refining business have been reclassified to gain (loss) on risk management activities from operating expense and purchased product, respectively.

ASSETS AND LIABILITIES CLASSIFIED AS HELD FOR SALE

Under previous GAAP, assets held for sale and liabilities related to assets held for sale were included as part of non-current assets and liabilities. Under IFRS, non-current assets that meet the definition of held for sale are required to be classified as current.

DEFERRED INCOME TAXES

A net deferred income tax asset has arisen at January 1, 2010 and December 31, 2010 related to the U.S. foreign operations, due to the adjustments noted above. Consistent with previous GAAP, a deferred income tax asset may not be offset against a deferred income tax liability in a different tax jurisdiction. Accordingly, $55 million and $3 million were reclassified to deferred income tax asset at December 31, 2010 and January 1, 2010, respectively.

L) NET EARNINGS PER SHARE

BASIC EARNINGS PER SHARE

Basic earnings per share under IFRS was impacted by the IFRS earnings adjustments discussed above.

DILUTED EARNINGS PER SHARE

Under previous GAAP, Cenovus's TSARs, which may be cash or equity settled at the option of the holder, had no dilutive effect on diluted earnings per share because cash settlement was assumed. Under IFRS, the more dilutive of cash settlement and share settlement is required to be used in calculating diluted earnings per share. The following table identifies the differences between previous GAAP and IFRS:

For the year ended December 31, 2010 ($ millions, except earnings per share)	Previous GAAP			IFRS		
	Net Earnings	Shares	Earnings per Share	**Net Earnings**	**Shares**	**Earnings per Share**
Net earnings per share – basic	993	751.9	$1.32	**1,081**	**751.9**	**$1.44**
Dilutive effect of exercised Cenovus TSARs	–	0.8		**–**	**0.8**	
Dilutive effect of outstanding Cenovus TSARs	–	–		**–**	**1.3**	
Net earnings per share – diluted	993	752.7	$1.32	**1,081**	**754.0**	**$1.43**

M) DEBT TO CAPITALIZATION RATIO

The transition to IFRS resulted in changes to the Company's Debt to Capitalization ratio as follows:

	December 31, 2010		January 1, 2010	
	Previous GAAP	**IFRS**	Previous GAAP	**IFRS**
Long-Term Debt	3,432	**3,432**	3,656	**3,656**
Debt	3,432	**3,432**	3,656	**3,656**
Shareholders' Equity	10,022	**8,395**	9,608	**7,809**
Total Capitalization	13,454	**11,827**	13,264	**11,465**
Debt to Capitalization ratio	26%	**29%**	28%	**32%**

Supplemental information (unaudited)

FINANCIAL STATISTICS

($ millions, except per share amounts)	**2011**					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**16,185**	4,480	3,989	4,085	3,631	13,090	3,471	3,069	3,217	3,333
Less: Royalties	**489**	151	131	76	131	449	108	107	123	111
Revenues	**15,696**	4,329	3,858	4,009	3,500	12,641	3,363	2,962	3,094	3,222
Operating Cash Flow										
Crude Oil and Natural Gas Liquids										
Foster Creek and Christina Lake	**905**	274	213	245	173	761	188	184	176	213
Pelican Lake	**305**	69	83	76	77	286	56	73	71	86
Conventional	**881**	246	209	218	208	758	188	183	161	226
Natural Gas	**777**	188	200	197	192	1,084	252	248	269	315
Other Upstream Operations	**13**	4	2	3	4	16	6	(1)	8	3
	2,881	781	707	739	654	2,905	690	687	685	843
Refining and Marketing	**981**	238	238	325	180	76	125	(26)	(20)	(3)
Operating Cash Flow [1]	**3,862**	1,019	945	1,064	834	2,981	815	661	665	840
Cash Flow Information										
Cash from Operating Activities	**3,273**	952	921	769	631	2,591	655	645	471	820
Deduct (Add back):										
Net change in other assets and liabilities	**(82)**	(20)	(17)	(16)	(29)	(55)	(14)	(13)	(13)	(15)
Net change in non-cash working capital	**79**	121	145	(154)	(33)	234	24	149	(53)	114
Cash Flow [2]	**3,276**	851	793	939	693	2,412	645	509	537	721
Per share - Basic	**4.34**	1.13	1.05	1.25	0.92	3.21	0.86	0.68	0.71	0.96
- Diluted	**4.32**	1.12	1.05	1.24	0.91	3.20	0.85	0.68	0.71	0.96
Operating Earnings [3]	**1,239**	332	303	395	209	799	147	156	143	353
Per share - Diluted	**1.64**	0.44	0.40	0.52	0.28	1.06	0.19	0.21	0.19	0.47
Net Earnings	**1,478**	266	510	655	47	1,081	78	295	183	525
Per share - Basic	**1.96**	0.35	0.68	0.87	0.06	1.44	0.10	0.39	0.24	0.70
- Diluted	**1.95**	0.35	0.67	0.86	0.06	1.43	0.10	0.39	0.24	0.70
Effective Tax Rates using										
Net Earnings	**33.0%**					17.1%				
Operating Earnings, excluding divestitures	**34.5%**					23.2%				
Canadian Statutory Rate	**26.7%**					28.2%				
U.S. Statutory Rate	**37.5%**					37.5%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**1.012**	0.978	1.020	1.033	1.015	0.971	0.987	0.962	0.973	0.961
Period end	**0.983**	0.983	0.963	1.037	1.029	1.005	1.005	0.971	0.943	0.985

(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 accounting 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)*

Financial Metrics (Non-GAAP measures)	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Debt to Capitalization [4], [5]	**27%**					29%				
Debt to Adjusted EBITDA [5], [6]	**1.0x**					1.3x				
Return on Capital Employed [7]	**13%**					11%				
Return on Common Equity [8]	**17%**					13%				

[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	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period end	**754.5**	754.5	754.3	754.1	753.9	752.7	752.7	752.0	751.8	751.7
Average - Basic	**754.0**	754.4	754.3	754.1	753.2	751.9	752.2	751.9	751.7	751.5
Average - Diluted	**757.7**	757.1	757.8	758.0	758.1	754.0	754.9	753.8	753.8	752.4
Price Range *($ per share)*										
TSX - C$										
High	**38.98**	37.11	38.38	38.98	38.90	33.40	33.40	31.00	30.63	27.84
Low	**28.85**	28.85	29.87	31.73	31.15	24.26	28.31	26.19	25.83	24.26
Close	**33.83**	33.83	32.27	36.40	38.30	33.28	33.28	29.59	27.40	26.53
NYSE - US$										
High	**40.73**	37.35	40.61	40.73	40.06	33.37	33.37	30.12	30.66	26.79
Low	**27.15**	27.15	29.02	32.48	31.11	22.87	27.78	24.61	23.84	22.87
Close	**33.20**	33.20	30.71	37.66	39.38	33.24	33.24	28.77	25.79	26.21
Dividends Paid *($ per share)*	**$ 0.80**	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.80	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Share Volume Traded *(millions)*	**873.7**	213.3	239.8	215.9	204.7	787.7	153.3	188.0	241.9	204.5

Net Capital Investment *($ millions)*	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Oil Sands										
Foster Creek	**429**	139	110	77	103	277	110	59	52	56
Christina Lake	**472**	126	117	121	108	346	105	93	85	63
Total	**901**	265	227	198	211	623	215	152	137	119
Pelican Lake	**317**	132	70	31	84	104	37	17	28	22
Other Oil Sands	**197**	68	9	11	109	130	52	16	19	43
	1,415	465	306	240	404	857	304	185	184	184
Conventional	**788**	330	193	89	176	526	220	136	68	102
Refining and Marketing	**393**	73	101	117	102	656	139	147	166	204
Corporate	**127**	35	31	30	31	76	38	11	26	1
Capital Investment	**2,723**	903	631	476	713	2,115	701	479	444	491
Acquisitions	**71**	49	1	2	19	86	48	4	34	–
Divestitures	**(173)**	(164)	–	(5)	(4)	(307)	5	(168)	(72)	(72)
Net Acquisition and Divestiture Activity	**(102)**	(115)	1	(3)	15	(221)	53	(164)	(38)	(72)
Net Capital Investment	**2,621**	788	632	473	728	1,894	754	315	406	419

OPERATING STATISTICS – BEFORE ROYALTIES

Upstream Production Volumes

	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands - Heavy										
Foster Creek	**54,868**	55,045	56,322	50,373	57,744	51,147	52,183	50,269	51,010	51,126
Christina Lake	**11,665**	19,531	10,067	7,880	9,084	7,898	8,606	7,838	7,716	7,420
Total	**66,533**	74,576	66,389	58,253	66,828	59,045	60,789	58,107	58,726	58,546
Pelican Lake	**20,424**	20,558	20,363	19,427	21,360	22,966	21,738	23,259	23,319	23,565
	86,957	95,134	86,752	77,680	88,188	82,011	82,527	81,366	82,045	82,111
Conventional Liquids										
Heavy Oil	**15,657**	15,512	15,305	15,378	16,447	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	**30,524**	32,530	30,399	27,617	31,539	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids [(1)]	**1,101**	1,097	1,040	1,087	1,181	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	**134,239**	144,273	133,496	121,762	137,355	129,187	129,593	128,067	128,566	130,549
Natural Gas *(MMcf/d)*										
Oil Sands	**37**	38	39	37	32	43	39	44	46	45
Conventional	**619**	622	617	617	620	694	649	694	705	730
Total Natural Gas	**656**	660	656	654	652	737	688	738	751	775

(1) Natural gas liquids include condensate volumes.

AVERAGE ROYALTY RATES

(excluding impact of realized gain (loss) on risk management)	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek [(1)]	**16.8%**	21.7%	20.6%	3.3%	21.2%	16.2%	20.4%	17.9%	19.0%	9.7%
Christina Lake	**5.2%**	4.7%	5.7%	6.3%	4.8%	3.9%	3.6%	3.9%	4.4%	4.0%
Pelican Lake	**11.5%**	9.1%	12.7%	9.7%	13.9%	21.1%	21.2%	18.5%	23.3%	21.4%
Conventional										
Weyburn	**24.1%**	24.8%	23.9%	23.6%	24.3%	22.2%	18.8%	23.2%	23.3%	23.3%
Other	**8.3%**	8.1%	9.0%	8.5%	7.6%	8.2%	7.2%	7.1%	9.1%	9.1%
Natural Gas Liquids	**1.7%**	1.8%	1.4%	2.3%	1.3%	1.9%	1.0%	2.4%	2.0%	2.1%
Natural Gas	**1.7%**	1.9%	1.5%	1.2%	2.3%	1.6%	1.7%	2.4%	1.7%	2.8%

(1) Foster Creek royalty rate was significantly lower in Q2 2011 as a result of the Alberta Department of Energy approving the expansion phases F, G and H capital investment to be included as part of the existing royalty calculation.

Refining

	2011					2010				
	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)*	**401**	424	413	406	362	386	410	401	379	355
Crude utilization	**89%**	94%	91%	90%	80%	86%	91%	89%	84%	79%
Refined products *(Mbbls/d)*	**419**	442	426	422	383	405	434	409	398	377

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

OPERATING STATISTICS – BEFORE ROYALTIES *(Continued)*

Selected Average Benchmark Prices	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
West Texas Intermediate ("WTI")	**95.11**	94.06	89.54	102.34	94.60	79.61	85.24	76.21	78.05	78.88
Western Canadian Select ("WCS")	**77.96**	83.58	71.92	84.70	71.74	65.38	67.12	60.56	63.96	69.84
Differential - WTI-WCS	**17.15**	10.48	17.62	17.64	22.86	14.23	18.12	15.65	14.09	9.04
Condensate - (C5 @ Edmonton)	**105.34**	108.74	101.48	112.33	98.90	81.91	85.24	74.53	82.87	84.98
Differential - WTI-Condensate (premium)/discount	**(10.23)**	(14.68)	(11.94)	(9.99)	(4.30)	(2.30)	-	1.68	(4.82)	(6.10)
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*										
Chicago	**24.55**	19.23	33.35	29.00	16.62	9.33	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	**25.26**	20.75	34.04	27.19	19.04	9.48	9.12	10.60	11.38	6.82
Natural Gas Prices										
AECO *($/GJ)*	**3.48**	3.29	3.53	3.54	3.58	3.91	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	**4.04**	3.55	4.19	4.31	4.11	4.39	3.80	4.38	4.09	5.30
Differential - NYMEX/AECO *(US$/MMBtu)*	**0.31**	0.17	0.34	0.42	0.29	0.40	0.28	0.78	0.32	0.19

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

PER-UNIT RESULTS

($, excluding impact of realized gain (loss) on risk management)	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* [1]										
Price	**67.38**	75.96	62.68	72.23	59.50	58.76	58.76	58.51	54.75	63.33
Royalties	**10.82**	15.81	12.38	2.30	11.92	9.08	11.41	9.56	9.38	5.76
Transportation and blending	**3.04**	3.20	2.73	2.82	3.41	2.42	2.54	2.40	2.40	2.33
Operating	**11.34**	11.31	11.11	11.57	11.40	10.40	9.93	10.32	10.36	11.04
Netback	**42.18**	45.64	36.46	55.54	32.77	36.86	34.88	36.23	32.61	44.20
Heavy Oil - Christina Lake *($/bbl)* [1]										
Price	**61.86**	66.69	54.52	67.06	54.67	57.96	58.42	56.45	54.99	62.27
Royalties	**3.03**	2.97	2.87	3.98	2.44	2.14	2.05	2.04	2.19	2.28
Transportation and blending	**3.53**	2.98	4.54	3.51	3.69	3.54	1.54	3.69	4.52	4.47
Operating	**20.20**	17.96	23.01	23.41	19.09	16.47	17.16	15.88	16.59	16.26
Netback	**35.10**	42.78	24.10	36.16	29.45	35.81	37.67	34.84	31.69	39.26
Heavy Oil - Pelican Lake *($/bbl)* [1]										
Price	**73.07**	88.67	66.76	78.26	64.66	62.65	61.38	58.93	62.05	68.04
Royalties	**7.91**	6.98	8.23	7.40	8.63	12.96	12.76	10.62	14.06	14.34
Transportation and blending	**4.14**	12.19	1.87	2.02	2.44	1.42	1.04	1.77	1.52	1.30
Operating	**14.86**	16.49	14.31	13.40	15.35	12.71	13.44	13.05	13.34	11.13
Netback	**46.16**	53.01	42.35	55.44	38.24	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands *($/bbl)* [1]										
Price	**67.99**	76.39	62.93	73.02	60.35	59.76	59.35	58.41	56.83	64.61
Royalties	**9.17**	11.72	10.46	3.65	10.08	9.53	10.79	9.30	10.03	7.94
Transportation and blending	**3.36**	4.75	2.68	2.71	3.18	2.25	2.08	2.35	2.35	2.23
Operating	**13.27**	13.54	13.02	13.27	13.23	11.66	11.49	11.74	11.82	11.57
Netback	**42.19**	46.38	36.77	53.39	33.86	36.32	34.99	35.02	32.63	42.87
Heavy Oil - Conventional *($/bbl)* [1]										
Price	**74.17**	81.49	67.96	78.47	69.17	63.18	60.45	59.40	61.35	71.16
Royalties	**10.75**	11.85	11.33	10.98	9.04	9.01	8.01	7.29	9.65	10.99
Transportation and blending	**1.27**	1.34	1.80	0.91	1.05	0.56	0.45	0.60	0.60	0.59
Operating	**13.77**	16.34	12.40	13.66	12.78	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	**0.32**	0.34	0.17	0.22	0.51	0.19	0.05	0.17	0.10	0.44
Netback	**48.06**	51.62	42.26	52.70	45.79	41.22	38.77	39.93	38.00	47.80

[1] The 2011 YTD 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 - $41.74/bbl; Christina Lake - $47.07/bbl; Pelican Lake - $16.32/bbl; Heavy Oil - Oil Sands - $36.57/bbl; Heavy Oil - Conventional - $12.73/bbl and Total Heavy Oil - $32.76/bbl.

OPERATING STATISTICS – BEFORE ROYALTIES *(Continued)*

PER-UNIT RESULTS

($, excluding impact of realized gain (loss) on risk management)	2011					2010				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Heavy Oil *($/bbl)* [1]										
Price	**68.98**	77.16	63.69	73.98	61.80	60.33	59.53	58.59	57.57	65.76
Royalties	**9.42**	11.74	10.59	4.93	9.91	9.44	10.36	8.95	9.97	8.48
Transportation and blending	**3.02**	4.23	2.55	2.40	2.83	1.97	1.83	2.04	2.06	1.94
Operating	**13.35**	13.96	12.93	13.34	13.16	11.75	11.75	11.68	12.02	11.53
Production and mineral taxes	**0.05**	0.05	0.03	0.04	0.08	0.03	0.01	0.03	0.02	0.08
Netback	**43.14**	47.18	37.59	53.27	35.82	37.14	35.58	35.89	33.50	43.73
Light and Medium Oil *($/bbl)*										
Price	**85.40**	90.90	79.57	94.30	77.39	71.63	72.98	68.37	66.14	78.78
Royalties	**11.54**	12.12	10.74	12.82	10.58	9.30	7.69	9.32	10.17	10.05
Transportation and blending	**2.00**	1.99	1.90	2.22	1.92	1.66	1.89	1.81	1.51	1.45
Operating	**14.38**	15.12	14.37	12.96	14.86	12.18	12.69	12.00	12.87	11.18
Production and mineral taxes	**2.27**	2.63	2.40	2.77	1.32	2.55	2.45	2.44	3.08	2.25
Netback	**55.21**	59.04	50.16	63.53	48.71	45.94	48.26	42.80	38.51	53.85
Total Crude Oil *($/bbl)*										
Price	**72.80**	80.49	67.37	78.71	65.32	62.98	62.75	60.86	59.51	68.87
Royalties	**9.92**	11.83	10.62	6.77	10.06	9.41	9.72	9.03	10.01	8.85
Transportation and blending	**2.78**	3.69	2.40	2.35	2.63	1.90	1.84	1.99	1.94	1.83
Operating	**13.59**	14.24	13.26	13.25	13.54	11.85	11.98	11.75	12.21	11.44
Production and mineral taxes	**0.57**	0.67	0.58	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**45.94**	50.06	40.51	55.67	38.73	39.20	38.62	37.50	34.64	46.16
Natural Gas Liquids *($/bbl)*										
Price	**76.84**	82.26	74.38	80.32	70.67	61.00	63.60	54.43	58.71	67.42
Royalties	**1.34**	1.51	1.06	1.87	0.93	1.12	0.75	1.29	1.16	1.39
Netback	**75.50**	80.75	73.32	78.45	69.74	59.88	62.85	53.14	57.55	66.03
Total Liquids *($/bbl)*										
Price	**72.84**	80.50	67.43	78.72	65.37	62.96	62.75	60.80	59.50	68.85
Royalties	**9.84**	11.75	10.55	6.72	9.98	9.33	9.63	8.96	9.93	8.78
Transportation and blending	**2.76**	3.66	2.38	2.33	2.60	1.88	1.82	1.97	1.94	1.83
Operating	**13.47**	14.13	13.16	13.13	13.43	11.74	11.82	11.64	12.10	11.34
Production and mineral taxes	**0.56**	0.67	0.57	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**46.21**	50.29	40.77	55.87	39.00	39.39	38.89	37.64	34.82	46.31
Total Natural Gas *($/Mcf)*										
Price	**3.65**	3.35	3.72	3.71	3.82	4.09	3.55	3.68	3.78	5.27
Royalties	**0.06**	0.06	0.05	0.04	0.08	0.07	(0.04)	0.08	0.07	0.14
Transportation and blending	**0.15**	0.14	0.15	0.14	0.17	0.17	0.16	0.15	0.15	0.21
Operating	**1.10**	1.22	0.99	0.98	1.19	0.95	1.02	0.93	0.92	0.93
Production and mineral taxes	**0.04**	0.01	0.03	0.05	0.06	0.02	0.02	0.03	(0.04)	0.07
Netback	**2.30**	1.92	2.50	2.50	2.32	2.88	2.39	2.49	2.68	3.92
Total *($/BOE)*										
Price	**49.75**	53.48	46.97	51.81	46.83	44.01	42.82	41.49	41.46	50.16
Royalties	**5.55**	6.65	5.91	3.64	5.85	4.93	4.90	4.73	5.26	4.81
Transportation and blending	**1.91**	2.39	1.70	1.61	1.92	1.45	1.40	1.42	1.43	1.53
Operating [2]	**10.35**	11.09	9.88	9.69	10.68	8.76	9.07	8.63	8.87	8.46
Production and mineral taxes	**0.41**	0.40	0.39	0.49	0.36	0.37	0.35	0.38	0.24	0.52
Netback	**31.53**	32.95	29.09	36.38	28.02	28.50	27.10	26.33	25.66	34.84

(1) The 2011 YTD 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 - $41.74/bbl; Christina Lake - $47.07/bbl; Pelican Lake - $16.32/bbl; Heavy Oil - Oil Sands - $36.57/bbl; Heavy Oil - Conventional - $12.73/bbl and Total Heavy Oil - $32.76/bbl.

(2) 2011 YTD operating costs include costs related to long-term incentives of $0.17/BOE (2010 - $0.16/BOE).

Impact of Realized Gain (Loss) on Risk Management

Liquids *($/bbl)*	**(2.79)**	(3.15)	0.75	(6.44)	(2.67)	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas *($/Mcf)*	**0.87**	1.10	0.76	0.74	0.89	1.07	1.50	1.09	1.22	0.53
Total *($/BOE)*	**0.86**	1.22	2.49	(1.25)	0.83	2.99	3.65	3.77	3.37	1.20

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" and "Risk Factors – Uncertainty of Reserves and Future Net Revenue Estimates" and "Uncertainty of Contingent and Prospective Resources Estimates", each within our Annual Information Form for the year ended December 31, 2011, available on our website at www.cenovus.com.

SUMMARY OF COMPANY INTEREST OIL AND GAS RESERVES AT DECEMBER 31, 2011

(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	162	105	82	1,145
Developed Non-Producing	6	15	8	34
Undeveloped	1,287	55	25	24
Total Proved Reserves	1,455	175	115	1,203
Probable Reserves	490	109	51	391
Total Proved plus Probable Reserves	1,945	284	166	1,594

AFTER ROYALTIES[2]

Reserves Category	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
Proved Reserves				
Developed Producing	121	86	70	1,152
Developed Non-Producing	5	12	5	34
Undeveloped	953	44	20	23
Total Proved Reserves	1,079	142	95	1,209
Probable Reserves	357	81	42	375
Total Proved plus Probable Reserves	1,436	223	137	1,584

Notes:

[1] Does not include Royalty Interest Reserves.

[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	–	2	4	45
Developed Non-Producing	–	–	–	–
Undeveloped	–	–	–	–
Total Proved Reserves	–	2	4	45
Probable Reserves	–	0	2	15
Total Proved plus Probable Reserves	–	2	6	60

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AT DECEMBER 31, 2011

(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	16,704	13,539	11,404	9,883	8,747	24.28
Developed Non-Producing	1,119	760	568	452	374	20.98
Undeveloped	45,721	19,864	10,121	5,677	3,352	9.91
Total Proved Reserves	63,544	34,163	22,093	16,012	12,473	14.56
Probable Reserves	25,192	12,571	6,881	4,169	2,746	12.68
Total Proved plus Probable Reserves	88,736	46,734	28,974	20,181	15,219	14.06

Note:
(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	13,094	10,668	9,017	7,837	6,954
Developed Non-Producing	834	567	425	340	282
Undeveloped	34,237	14,747	7,434	4,110	2,379
Total Proved Reserves	48,165	25,982	16,876	12,287	9,615
Probable Reserves	18,705	9,294	5,057	3,042	1,989
Total Proved plus Probable Reserves	66,870	35,276	21,933	15,329	11,604

Note:
(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, 2011.

The estimates of future net revenue presented do not represent fair market value.

RESERVES RECONCILIATION

The following tables provide a reconciliation of our Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2011, 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, 2010	1,154	169	111	1,390
Extensions and Improved Recovery	256	16	13	50
Discoveries	–	–	–	–
Technical Revisions	69	2	1	29
Economic Factors	–	1	–	(28)
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Production [1]	(24)	(13)	(10)	(238)
December 31, 2011	1,455	175	115	1,203

PROBABLE

	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2010	523	97	49	410
Extensions and Improved Recovery	32	14	3	11
Discoveries	–	–	–	–
Technical Revisions	(65)	(2)	(1)	(27)
Economic Factors	–	–	–	(3)
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Production [1]	–	–	–	–
December 31, 2011	490	109	51	391

PROVED PLUS PROBABLE

	Bitumen *(MMbbls)*	Heavy Oil *(MMbbls)*	Light & Medium Oil & NGLs *(MMbbls)*	Natural Gas & CBM *(Bcf)*
December 31, 2010	1,677	266	160	1,800
Extensions and Improved Recovery	288	30	16	61
Discoveries	–	–	–	–
Technical Revisions	4	–	–	2
Economic Factors	–	1	–	(31)
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Production [1]	(24)	(13)	(10)	(238)
December 31, 2011	1,945	284	166	1,594

Note:

[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.

ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES

Company Interest Before Royalties, Billions of barrels	December 31, 2011	December 31, 2010
Economic Contingent Resources [1]		
Low Estimate	6.0	4.4
Best Estimate	8.2	6.1
High Estimate	10.8	8.0
Prospective Resources [2]		
Low Estimate	5.7	7.3
Best Estimate	10.0	12.3
High Estimate	17.9	21.7

Notes:

(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
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
2009:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	4	4	–	–	–	–	4	4	8	12	4
Total Canada	4	4	–	–	–	–	4	4	8	12	4

DEVELOPMENT WELLS DRILLED

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
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
2009:											
Oil Sands	50	29	8	8	8	8	66	45	10	76	45
Conventional	102	101	555	502	2	2	659	605	261	920	605
Total Canada	152	130	563	510	10	10	725	650	271	996	650

During the year ended December 31, 2011, Oil Sands drilled 480 gross stratigraphic test wells (344 net wells) and Conventional drilled 11 gross stratigraphic test wells (11 net wells).

During the year ended December 31, 2011, Oil Sands drilled 62 gross service wells (50 net wells) and Conventional drilled 30 gross service wells (20 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, 2011:

LANDHOLDINGS

	Developed		Undeveloped (1)		Total (2)	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown (3)	621	519	1,974	1,552	2,595	2,071
Conventional						
– Fee (4)	1,936	1,936	436	436	2,372	2,372
– Crown (3)	1,567	1,461	350	283	1,917	1,744
– Freehold (5)	59	49	29	27	88	76
Total Alberta	4,183	3,965	2,789	2,298	6,972	6,263
Saskatchewan:						
Conventional						
– Fee (4)	75	75	431	431	506	506
– Crown (3)	54	40	310	289	364	329
– Freehold (5)	14	10	16	14	30	24
Total Saskatchewan	143	125	757	734	900	859
Manitoba:						
Conventional – Fee (4)	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,329	4,093	3,807	3,293	8,136	7,386

Notes:

(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.

(2) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.

(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which we have purchased a working interest lease.

(4) Fee lands are those lands in which we have a fee simple interest in the mineral rights and have either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands summary 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

OIL AND GAS INFORMATION

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, 2011 (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 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.

Resources

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. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development.

Economic Contingent Resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. All of Cenovus's bitumen contingent resources were evaluated using the same commodity price assumptions that were used for the 2011 reserves evaluation.

Prospective Resources are those quantities of bitumen 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 sub-classified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

Best Estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent confidence level that the actual quantities recovered will equal or exceed the estimate.

Low Estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty, a 90 percent confidence level, that the actual quantities recovered will equal or exceed the estimate.

High Estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty, a 10 percent confidence level, that the actual quantities recovered will equal or exceed the estimate.

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.

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

NON-GAAP MEASURES

Certain financial measures in our Annual Report do not have a standardized meaning as prescribed by IFRS such as cash flow, operating cash flow, operating earnings, adjusted EBITDA, debt and capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in our MD&A in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in our MD&A.

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 $13.99/BOE for the year ended December 31, 2011, $10.55/BOE for the year ended December 31, 2010 and averaged $13.05/BOE for the three years ended December 31, 2011. 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 $10.69/BOE for the year ended December 31, 2011, $9.78/BOE for the year ended December 31, 2010 and averaged $12.37/BOE for the three years ended December 31, 2011. 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 15, 2012 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 adjusted for the dilutive effect of stock options or other contracts as at December 31. We calculate NAV as an average of (i) our average TSX 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 downstream data and using internal corporate costs, with one based on constant prices and costs and one based on forecast prices and costs.

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”, “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 including technology and procedures to reduce our environmental impact 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; the estimation 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 2012 guidance is based include: WTI of US$90.00/bbl; Western Canada Select of US$75.00/bbl; NYMEX of US$3.50/MMBtu; AECO of $3.10/GJ; Chicago 3-2-1 Crack Spread of US$14.50; exchange rate of $0.975 US$/C$; and an average diluted number of shares outstanding of approximately 759 million. The assumptions on which our forecasts for the period 2013 to 2021 are based include: WTI of US$85.00-US$105.00/bbl; Western Canada Select of US$71.00-US$85.00/bbl; NYMEX of US$4.00-US$6.00/MMBtu; AECO of $3.30-$5.25/GJ; Chicago 3-2-1 crack spread of US$9.00; exchange rate of $0.98-$1.07 US$/C$; and average diluted number of shares outstanding of approximately 752 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; 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; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in 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 Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 (see Additional Information).

ABBREVIATIONS AND CONVERSIONS

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

OIL AND NATURAL GAS LIQUIDS

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
WTI	West Texas Intermediate
WCS	Western Canadian Select
TM	Trademark of Cenovus Energy Inc.

NATURAL GAS

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

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.

ADDITIONAL INFORMATION

The Arrangement refers to the plan of arrangement with Encana Corporation, effective November 30, 2009, resulting in the split of Encana into Cenovus and Encana, whereby Encana shareholders received, for each Encana common share held, one common share of each of Cenovus and the new Encana. Pursuant to the Arrangement, Cenovus commenced independent operations on December 1, 2009.

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, 2011, 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

Judy A. Fairburn
Executive Vice-President,
Environment & Strategic
Planning

Sheila M. McIntosh
Executive Vice-President,
Communications &
Stakeholder Relations

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

Donald T. Swystun
Executive Vice-President,
Refining, Marketing,
Transportation &
Development

Hayward J. Walls
Executive Vice-President,
Organization & Workplace
Development

CENOVUS HEAD & REGISTERED OFFICE

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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 25, 2012 at 2 p.m. (Calgary time) at Telus Convention Centre, Exhibition Hall E, 2nd Floor, North Building, 136 – 8th Avenue SE, Calgary, Alberta.

Please see our management proxy circular available on our website, cenovus.com, for additional information.

TRANSFER AGENTS & REGISTRAR

In Canada, CIBC Mellon Trust Company* In the United States, Computershare.

*Canadian Stock Transfer Company Inc. (CST) purchased the issuer services business and is currently operating in the name of CIBC Mellon Trust company during a transitional period.

Canadian Stock Transfer Company Inc.
P.O. Box 700, Station B
Montreal, Quebec H3B 3K3
www.canstockta.com

Shareholder Inquiries by phone: 1.866.332.8898 (North America, English & French) or 1.416.682.3862 (outside North America) or by facsimile: 1.888.249.6189 or 1.514.985.8843.

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 Canadian Stock Transfer Company 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 U.S. 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:
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investor.relations@cenovus.com

or

Susan Grey
Director, Investor Relations
403.766.4751
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or

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Cenovus Energy is a Canadian 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, and established natural gas and oil production in Alberta and Saskatchewan. We also have 50 percent ownership in two U.S. refineries.

cenovus.com

twitter.com/cenovus
facebook.com/cenovus
youtube.com/user/cenovusenergy
linkedin.com/company/cenovus-energy

421 – 7 Avenue SW PO Box 766
Calgary, Alberta, Canada T2P 0M5

A DIFFERENT OIL SANDS *Building on the ads we created in 2010 that were focused on the value oil and natural gas bring to our lives, we launched another ad in 2011. It featured our Foster Creek project, pictured here, and invited Canadians to see a different side to the oil sands.*

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