News release

Cenovus total proved reserves up 12% to 2.2 billion BOE

Oil sands production increases 35% in 2012

- Proved bitumen reserves at the end of 2012 were more than 1.7 billion barrels (bbls), up 18% from 2011.
- Economic bitumen best estimate contingent resources at year end were 9.6 billion bbls, a 17% increase over 2011.
- Combined oil sands production at Foster Creek and Christina Lake averaged nearly 90,000 barrels per day (bbls/d) net in 2012, up 35% from 2011. Average production at Christina Lake nearly tripled in 2012 to almost 32,000 bbls/d net.
- Christina Lake phase D reached full capacity about six months after first production.
- Cash flow increased to about $3.6 billion in 2012, up 11% from 2011.
- The Board of Directors approved a dividend increase of 10% for the first quarter of 2013 resulting in a quarterly dividend of $0.242 per share.
- Cenovus recorded a $393 million non-cash goodwill impairment in the fourth quarter which resulted in lower 2012 operating earnings and a fourth quarter earnings loss. This impairment related to the company's Suffield assets, principally natural gas.

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

Financial & production summary

(for the period ended December 31) ($ millions, except per share amounts)	**2012 Q4**	2011 Q4	% change	**2012 Full Year**	2011 Full Year	% change
Cash flow[1]	**697**	851	-18	**3,643**	3,276	11
Per share diluted	**0.92**	1.12		**4.80**	4.32	
Operating earnings/loss[1]	**-189**	332	-157	**866**	1,239	-30
Per share diluted	**-0.25**	0.44		**1.14**	1.64	
Net earnings/loss	**-118**	266	-144	**993**	1,478	-33
Per share diluted	**-0.16**	0.35		**1.31**	1.95	
Capital investment[2]	**978**	903	8	**3,368**	2,723	24
Production (before royalties)						
Oil sands total (bbls/d)	**100,867**	74,576	35	**89,736**	66,533	35
Conventional oil[3] (bbls/d)	**76,779**	69,697	10	**75,667**	67,706	12
Total oil (bbls/d)	**177,646**	144,273	23	**165,403**	134,239	23
Natural gas[4] (MMcf/d)	**566**	660	-14	**594**	656	-9

[1] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.
[2] Includes expenditures on property, plant and equipment and exploration and evaluation assets, excluding acquisitions and divestitures.
[3] Includes natural gas liquids (NGLs) production and production from Pelican Lake.
[4] Reflects the divestiture of a non-core property in the first quarter of 2012.

Calgary, Alberta (February 14, 2013) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered another year of predictable, reliable performance in 2012. In addition to growing its reserves and resources base, the company recorded solid operational results driven by significant production growth and a strong contribution from its downstream refining business. Those results offset the impact of a reduction in average realized prices for crude oil and natural gas when compared with 2011. Average daily oil production grew 23% in 2012 while total cash flow rose 11% compared with the previous year. The company's Christina Lake oil sands project led the growth in production, nearly tripling its average daily output from 2011. Christina Lake phase D achieved one of the fastest ramp-ups in the steam-assisted gravity drainage (SAGD) industry, demonstrating full production capacity about six months after first oil production. At Cenovus's U.S. refineries, strong margins and increased heavy oil processing capacity led to a 29% increase in operating cash flow from refining.

"Our integrated approach continues to support our bottom line," Ferguson said. "When our heavy oil producing assets are affected by low commodity prices, we make up that value at our refineries. For 2013, we have supply agreements and firm transportation and hedging contracts that, together with our refining capacity, will enable us to offset almost all of our volume exposure to discounted Canadian heavy crude prices."

Strong additions to reserves and contingent resources

Cenovus continues to strengthen its reserves and resources base. According to the company's independent reserves and contingent resources evaluation, total proved reserves were nearly 2.2 billion bbls of oil equivalent (BOE) at the end of 2012, up 12% from the previous year.

Proved bitumen reserves increased 18% to more than 1.7 billion bbls, compared with 2011, while proved plus probable bitumen reserves increased approximately 23% to nearly 2.4 billion bbls. Economic bitumen best estimate contingent resources increased 17% from 2011 to 9.6 billion bbls. Proved light and medium oil reserves remained unchanged, while proved heavy oil reserves increased approximately 5% and proved natural gas reserves declined about 21% compared with 2011. Cenovus's 2012 proved finding and development (F&D) costs, excluding changes in future development costs, were a competitive $9.04/BOE. The three-year average was $6.10/BOE. The 2012 recycle ratio was 3.2 times.

"Cenovus's stratigraphic well program continues to add significant new resources to our already strong portfolio of oil sands assets," Ferguson said. "This gives us even greater opportunity to develop new projects, move them through the regulatory approvals process and create decades of solid growth ahead."

Integrated operations contribute to solid financial performance

Cenovus achieved cash flow of more than $3.6 billion, an 11% increase from the previous year. Operating cash flow from refining benefited from the fact that the Wood River Refinery was able to process higher volumes of heavy oil as a result of the completion of the coker and refinery expansion (CORE) project in late 2011. While lower commodity prices had a negative impact on cash flow from the company's oil producing assets, the ongoing price volatility provided a double benefit to Cenovus's refining operations. Compared with 2011, the price of Western Canadian Select (WCS), the benchmark Canadian heavy oil blend, fell against the price of West Texas Intermediate (WTI), the North American benchmark. The wider WTI-WCS differential resulted in lower feedstock costs for the company's refineries. At the same time, there was a favourable appreciation in the price of Brent crude, the global benchmark, against the price of WTI, which allowed Cenovus's refineries to capture higher prices for their finished products. Those lower feedstock costs and higher finished product prices led to stronger refining margins, which also contributed to the 29% improvement in operating cash flow from refining when compared with 2011.

Goodwill impairment impacts earnings
A one-time non-cash goodwill write down of $393 million in the company's conventional operations contributed to lower full year operating earnings in 2012 and to an operating loss of $189 million in the fourth quarter. For the full year, the company had operating earnings of $866 million, down 30% from 2011. The full year decrease and quarterly loss were primarily due to the goodwill impairment related to the company's Suffield conventional assets, located on the Canadian Forces Base in southeast Alberta. Estimated future cash flows for the assets have declined, largely as the result of a drop in forecast natural gas prices over the long term. As a result, the carrying amount of goodwill related to the property has exceeded its fair value and was written off. The goodwill in question arose from the 2002 merger between Alberta Energy Company and PanCanadian Energy Corporation.

Continued focus on operating costs
Managing operating costs is an important ongoing focus for Cenovus. Operating costs per BOE at the company's oil sands and natural gas operations were largely in line with Cenovus's 2012 forecasts, while operating costs at its Pelican Lake heavy oil operations were slightly above guidance. Cenovus anticipates more pressure on operating costs in 2013 as a result of expected higher prices for natural gas and electricity needed to fuel the company's operations. Operating costs at Pelican Lake are expected to rise again this year with the expansion of the polymer flood as temporarily reduced reservoir pressure required to safely complete infill drilling limits 2013 production growth. Stronger production growth is expected in late 2013 and into 2014, which should help reduce per barrel operating costs.

"Cenovus is working diligently to maintain our reputation as a low cost producer," said John Brannan, Cenovus Executive Vice-President and Chief Operating Officer. "We will continue to focus on reducing our costs per barrel and increasing efficiency across all of our operations."

Growing net asset value
Cenovus measures its success in a number of ways with a key metric being growth in net asset value (NAV). The company remains on track to reach its goal of doubling its December 2009 baseline illustrative NAV of $28 by the end of 2015. Despite weaker oil and gas prices, Cenovus's operational and financial performance and consistent production growth allowed the company to increase its NAV to approximately $40 in 2012, a 43% increase from the end of 2009.

Capital investment supports oil production growth

Cenovus is focused on creating value through its oil growth strategy, which remains on track with plans to achieve 500,000 bbls/d of net production by the end of 2021. As part of that strategy, the company invested almost $3.4 billion in its operations in 2012, a planned 24% increase from the previous year. About half of that capital spending supported development of the company's oil sands assets. Nearly $1.4 billion went towards expansions at Foster Creek and Christina Lake and the development of Narrows Lake. Capital spending on emerging oil sands projects, including Grand Rapids and Telephone Lake, was approximately $316 million. Capital investment in 2012 included the drilling of 473 gross stratigraphic test wells. The results of these stratigraphic test wells will be used to support the expansion and development of the company's oil sands projects.

Cenovus spent nearly $1.3 billion on its conventional oil assets in 2012. That includes more than $500 million at Pelican Lake to increase infill drilling for the polymer flood programs and facility expansion. The company invested nearly $850 million in its other conventional oil assets, including the continued development of its emerging tight oil plays.

Cenovus's capital program includes investing in innovative technologies aimed at increasing production, while lowering operating costs per BOE and decreasing environmental impacts. In 2012, this led to continued investment in projects such as Cenovus's enhanced start-up and patented Wedge Well™ technologies as well as the development of its new SkyStrat™ drilling rig, a scaled-down version of a traditional stratigraphic drilling rig that can be transported to remote sites by helicopter.

Acquisitions and divestitures

While Cenovus does not have a need for major acquisitions or divestitures, the company is always looking for tuck-in opportunities that would enhance its current portfolio. Cenovus places value on maintaining a divestiture program as a form of capital discipline and will continue to assess the benefits of selling certain non-core assets. Purchases in 2012 were primarily tuck-in oil sands acquisitions adjacent to Cenovus's Telephone Lake and Narrows Lake properties as well as tuck-in acquisitions of producing conventional crude oil properties in Alberta and Saskatchewan, adjacent to existing production. Divestitures in 2012 were mainly related to the sale of a non-core natural gas property in northern Alberta in the first quarter.

Following a portfolio review, Cenovus decided to put its Lower Shaunavon property and the operated part of its Bakken property in Saskatchewan up for sale. The company believes these are quality assets. However, Cenovus is unable to scale the projects up to a size that would be material to its portfolio due to competitive limitations on increasing its land base in the area. The sale process is expected to launch later this quarter.

Addressing market access challenges

Constraints on market access are having a negative impact on realized pricing for Canadian oil producers. Congestion on pipelines linking oil fields in Western Canada to U.S. markets contributed to a widening of the average discount (also known as the light/heavy differential) between WTI and WCS in 2012. The average WTI-WCS differential was US$30.37/bbl in December 2012 compared to US$11.72/bbl in December of 2011.

"Widening oil price differentials are becoming an increasingly important issue, not just for producers, but for all Canadians," Ferguson said. "With the third largest oil reserves in the world, we have a tremendous opportunity to capitalize on the growing global demand for energy. However, without pipeline access to new markets we will continue to leave billions of dollars in lost revenues on the table every year, to the detriment of the entire Canadian economy."

Cenovus takes a portfolio approach to market access and continues to proactively assess various options to transport its oil. The predictability of the company's oil production growth gives it the confidence to support all currently proposed pipeline projects that would open up new markets. Early in 2012, Cenovus started shipping 11,500 bbls/d of oil under a firm service agreement on the Trans Mountain pipeline that runs from Edmonton to the West Coast. The firm service agreement is beneficial as it gives Cenovus the ability to get its oil to tidewater where it commands higher prices and it allows the company to negotiate longer term arrangements for markets in California and Asia. In addition to pipelines, Cenovus is now shipping about 6,000 bbls/d of conventional crude volumes to market by rail and is looking to increase that to about 10,000 bbls/d in 2013.

Oil Projects

Daily production[1]

(Before royalties) (Mbbls/d)	2012					2011					2010
	Full Year	**Q4**	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands											
Foster Creek	**58**	**59**	63	52	57	55	55	56	50	58	51
Christina Lake	**32**	**42**	32	29	25	12	20	10	8	9	8
Oil sands total	**90**	**101**	96	80	82	67	75	66	58	67	59
Conventional oil											
Pelican Lake	**23**	**24**	24	22	21	20	21	20	19	21	23
Weyburn	**16**	**16**	16	16	17	16	17	16	15	17	17
Other conventional[2]	**37**	**37**	36	36	38	31	32	31	29	32	31
Conventional total	**76**	**77**	76	75	75	68	70	67	64	71	70
Total oil[2]	**165**	**178**	171	156	157	134	144	133	122	137	129

[1] Totals may not add due to rounding.
[2] Includes NGLs production.

Oil sands

Cenovus has a substantial portfolio of oil sands assets in northern Alberta with the potential to provide decades of future growth. The two currently producing operations, Foster Creek and Christina Lake, use SAGD to drill and pump the oil to the surface. These projects are operated by Cenovus and are jointly owned with ConocoPhillips. Cenovus also has an enormous opportunity to deliver increased shareholder value through production growth from future developments. The company has identified several emerging projects and continues to assess its resources to prioritize development plans and support regulatory applications for new projects.

Foster Creek and Christina Lake

Production

- Combined production at Foster Creek and Christina Lake increased 35% to almost 90,000 bbls/d net in 2012 compared with the previous year. Fourth quarter production also rose 35% in 2012 to nearly 101,000 bbls/d net, compared to the same period in 2011.
- Christina Lake production almost tripled to an average of about 32,000 bbls/d net in 2012, compared with the previous year. Christina Lake produced an average of approximately 42,000 bbls/d net in the fourth quarter, more than double the average production rate in the same period a year earlier.
- The substantial increase in production at Christina Lake was due to the ramp-up of two new expansion phases. Phase C reached full capacity in the first quarter of 2012. Phase D began producing in July 2012, approximately three months ahead of schedule. It demonstrated full production capacity in January 2013, approximately six months after first production.
- Foster Creek produced an average of nearly 58,000 bbls/d net in 2012, about 5% more than the 2011 average due to improved well performance and plant optimization. Fourth quarter production at Foster Creek averaged about 59,000 bbls/d net to Cenovus.
- Both Christina Lake and Foster Creek achieved new single-day production highs of almost 47,000 and 65,500 bbls/d net respectively in 2012.
- About 12% of current production at Foster Creek comes from 56 wells using Cenovus's Wedge Well™ technology. These single horizontal wells, drilled between existing SAGD well pairs, reach oil that would otherwise be unrecoverable. The company's Wedge Well™ technology has the potential to increase overall recovery from the reservoir by as much as 10%, while reducing the steam to oil ratio (SOR). Cenovus plans to drill and complete an additional eight wells at Foster Creek using Wedge Well™ technology in 2013.
- Christina Lake is also benefiting from the use of Wedge Well™ technology with six of these wells now producing and another four drilled wells expected to begin producing in the first half of 2013.

Expansions

- The overall Christina Lake phase E project is about 65% complete, while the central plant is nearly 87% complete. First production is anticipated in the third quarter of 2013. Piling and foundation work, engineering and major equipment fabrication continue for phase F and design engineering work is under way for phase G.
- At Foster Creek, overall progress of the combined F, G and H expansion is approximately 40% complete, while the phase F central plant is 67% complete. First production at phase F is expected in the third quarter of 2014. Spending on piling work, steel fabrication, module assembly and major equipment procurement is under way at phase G and design engineering continues at phase H.
- Combined capital investment at Foster Creek and Christina Lake was more than $1.3 billion in 2012, a 46% increase compared with 2011. This includes spending on the expansion phases, stratigraphic test wells and maintenance capital.

Operating costs

- Operating costs at Foster Creek averaged $11.99/bbl in 2012, about a 6% increase from $11.34/bbl the previous year. Non-fuel operating costs at Foster Creek were $9.96/bbl in 2012 compared with $9.14/bbl in 2011, a 9% increase. The increases were mostly due to added costs from hiring additional staff, as well as higher levels of waste and fluid handling, trucking and workover activity.
- Operating costs at Christina Lake were $12.95/bbl in 2012, a 36% decrease from $20.20/bbl the previous year. Non-fuel operating costs at Christina Lake were $10.53/bbl in 2012 compared with $17.02/bbl in 2011, a 38% decrease. The decreases were primarily due to the significant increase in production at Christina Lake in 2012 and lower SORs.

Steam to oil ratios

- SOR measures the number of barrels of steam needed for every barrel of oil produced, with Cenovus having one of the lowest ratios in the industry. A lower SOR means less natural gas is used to generate the steam, which results in reduced capital and operating costs, fewer emissions and lower water usage.
- Cenovus continued to achieve low SORs in 2012 with ratios of approximately 2.2 at Foster Creek, unchanged from 2011, and 1.9 at Christina Lake, down from 2.3 in 2011. The combined SOR for Cenovus's oil sands operations was about 2.1 in 2012.

Christina Dilbit Blend

- Christina Dilbit Blend (CDB) is a heavy bitumen blend stream launched in the fourth quarter of 2011. Last year, 74% of production from Christina Lake was sold as CDB.
- While CDB is priced at a discount to WCS, it is gaining acceptance with a wider base of refiners. Cenovus continued to add CDB into its contracts with downstream customers and saw the price differential narrow last year.
- In the fourth quarter of 2012 the CDB discount to WCS was in the US$4.50 to US$7.50/bbl range. Over the longer term, Cenovus expects a CDB to WCS discount in the US$3.00/bbl to US$5.00/bbl range.
- The Wood River Refinery ran approximately 84,000 bbls/d gross of CDB or equivalent crudes during the fourth quarter of 2012. These crudes represented 55% of total

heavy crude volumes in the fourth quarter, up from 40% in the third quarter of 2012.

Emerging projects

Narrows Lake

- Cenovus's next major oil sands development, a three-phase project at Narrows Lake, received regulatory approval in 2012 as well as partner approval for the first phase. As a result of the approvals, Cenovus booked more than 200 million bbls of proved reserves last year. The project is 50%-owned with ConocoPhillips and Cenovus is the operator. Narrows Lake is expected to be the industry's first project to demonstrate solvent aided process (SAP), with butane, on a commercial scale. Site preparation began in the third quarter of 2012 and phase A construction is scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have production capacity of 45,000 bbls/d, with first oil expected in 2017. Cenovus spent $44 million on Narrows Lake in 2012.

Grand Rapids

- At the company's 100%-owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is under way. The project is progressing smoothly with steaming of a second well pair, which is expected to begin producing this month. A joint regulatory application and Environmental Impact Assessment (EIA) for a 180,000 bbl/d commercial project has been submitted and is proceeding on schedule. Cenovus anticipates regulatory approval for Grand Rapids by the end of 2013.

Telephone Lake

- Cenovus's 100%-owned Telephone Lake property is located within the Borealis Region of northern Alberta. A revised joint application and EIA submitted in December 2011 is advancing through the regulatory process and approval is anticipated early in 2014. Cenovus is continuing with its dewatering pilot project designed to remove a layer of non-potable water that is sitting on top of the oil sands deposit at Telephone Lake. The dewatering operations have been running smoothly and early results are encouraging. While dewatering is not essential to the development of Telephone Lake, Cenovus believes it could improve the project's SORs by up to 30%, enhancing its economics and reducing its impact on the environment.

Conventional oil

Pelican Lake

Cenovus produces heavy oil from the Wabiskaw formation at its wholly-owned Pelican Lake operation in the Greater Pelican Region, about 300 kilometres north of Edmonton. While this property produces conventional heavy oil, it's managed as part of Cenovus's oil sands segment. Since 2006, Cenovus has been injecting polymer to enhance production from the reservoir, which is also under waterflood. Based on reservoir performance of the polymer program, the company has a multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d.

- Pelican Lake produced nearly 23,000 bbls/d in 2012, a 10% increase in production compared with 2011 due to the expansion of infill drilling and polymer injection.
- Cenovus plans to build on its success at Pelican Lake by drilling about 1,000 additional production and injection wells in the next five to seven years to expand the polymer flood.
- Operating costs at Pelican Lake averaged $17.08/bbl in 2012, a 15% increase from $14.86/bbl in 2011. Per barrel operating costs have been impacted by lower than expected production growth due to reduced operating pressures related to temporary well shut-ins required to complete infill drilling between existing wells at Pelican Lake.
- Operating costs at Pelican Lake were also higher due to additional workover activities, increased staffing levels and polymer consumption as a result of the expansion of the polymer flood.
- Stronger production growth is expected in late 2013 and into 2014, which should help reduce per barrel operating costs.

Other conventional oil

In addition to Pelican Lake, Cenovus has extensive oil operations in Alberta and Saskatchewan. These include conventional and tight oil assets in Alberta and developing tight oil assets in southern Saskatchewan, as well as the established Weyburn operation that uses carbon dioxide injection to enhance oil recovery.

- Alberta oil production averaged more than 30,000 bbls/d in 2012, up 10% from the previous year, primarily due to successful tight oil drilling programs and fewer weather and access issues than in 2011.
- Production at the Weyburn operation was unchanged compared to the previous year at more than 16,000 bbls/d net.
- Combined crude oil production from the Bakken and Lower Shaunavon operations averaged nearly 6,500 bbls/d, a 79% increase from the previous year due to increased drilling. Given the limited expansion opportunities that Cenovus has in these non-core properties in comparison to its other holdings, the company has determined it will commence a public process later this quarter to dispose of its interests in the Lower Shaunavon property and the operated part of its Bakken property.
- Operating costs for Cenovus's conventional oil and liquids operations, excluding Pelican Lake, increased 9% to $15.12/bbl in 2012 compared with 2011. This was mainly due to a combination of higher levels of waste and fluid handling, trucking, workover activities, repairs and maintenance in connection with single well batteries and higher workforce costs.

Natural Gas

(Before royalties) (MMcf/d)	Daily production									
	2012					2011				2010
	Full Year	**Q4**	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas[1]	**594**	**566**	577	596	636	656	660	656	654	652	737

[1] Reflects the divestiture of a non-core property in the first quarter of 2012.

Cenovus has a solid base of established, reliable natural gas properties in Alberta. These assets are an important component of the company's financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations, because natural gas fuels the company's oil sands and refining operations.

- Natural gas production in 2012 was approximately 594 million cubic feet per day (MMcf/d), down 9% from the previous year, as expected. The production drop was driven primarily by expected natural declines and the divestiture of a non-core property early in the first quarter of 2012. Excluding the impact of the divestiture, natural gas production would have been 6% lower than in 2011.
- Cenovus's average realized sales price for natural gas, including hedges, was $3.56 per thousand cubic feet (Mcf) in 2012 compared with $4.52 per Mcf in 2011.
- The company invested $51 million in its natural gas properties in 2012. Operating cash flow from natural gas in excess of capital investment was $462 million.
- Cenovus anticipates managing an annual decline rate of 10% to 15% for its natural gas production, targeting a long-term production level of between 400 MMcf/d and 500 MMcf/d to match Cenovus's future anticipated internal consumption at its oil sands and refining facilities.

Refining

Cenovus's refining operations allow the company to capture value from crude oil production through to refined products such as diesel, gasoline and jet fuel. This integrated strategy provides a natural economic hedge against reduced crude oil prices by providing lower feedstock prices to Cenovus's Wood River Refinery in Illinois and Borger Refinery in Texas, which are jointly owned with the operator, Phillips 66.

- Operating cash flow from refining increased $282 million to nearly $1.3 billion, 29% more than in 2011. This was due to higher benchmark crack spreads as well as the benefits from the completion of the CORE project at the Wood River Refinery in late 2011, including lower feedstock costs and improved refinery output.
- Operating cash flow for 2012 would have been higher if not for planned fourth quarter major turnarounds at Wood River and Borger that continued longer than expected.
- Cenovus's operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by

most U.S. refiners, Cenovus's 2012 refining operating cash flow would have been $111 million higher than reported under FIFO, compared with $95 million lower in 2011.

- For the full year, the company’s refining business generated $1.14 billion of operating cash flow in excess of the $118 million of capital invested in it.
- Cenovus expects strong first quarter 2013 operating cash flow from its refineries in the range of $300 million to $400 million.
- Both refineries combined processed an average of 412,000 bbls/d of crude oil in 2012, resulting in 433,000 bbls/d of refined product output, which was 3% higher than in 2011.
- Total combined heavy crude oil processing capacity at the company’s refineries increased to between 235,000 bbls/d and 255,000 bbls/d with the completion of the CORE project at the Wood River Refinery in late 2011. The CORE project has enhanced the company’s ability to further integrate its growing bitumen production.
- The amount of Canadian heavy oil processed in 2012 increased 57% to 198,000 bbls/d.
- Refinery crude utilization rates averaged 91% in 2012.

Reserves and Contingent Resources

All of Cenovus’s reserves and resources are evaluated each year by independent qualified reserves evaluators.

- At year-end 2012, Cenovus had proved reserves of nearly 2.2 billion BOE, an increase of 12% compared with 2011.
- Proved bitumen reserves increased 18% in 2012 compared with 2011, to more than 1.7 billion bbls, while proved plus probable bitumen reserves grew nearly 23% to approximately 2.4 billion bbls. This increase was primarily due to regulatory and partner approval of the company’s Narrows Lake oil sands project and substantial reserves additions at Foster Creek and Christina Lake. The reserves additions at Christina Lake were due to increased well density and improved SOR performance. At Foster Creek the reserves additions were due to more efficient drainage of oil in the steam chambers.
- Economic bitumen best estimate contingent resources increased to 9.6 billion bbls, up approximately 17% from 2011. This increase is a result of Cenovus’s extensive stratigraphic test well drilling program converting prospective resources to contingent resources. In addition, the independent evaluators recognized commercial SAGD feasibility in the Wabiskaw formation within the Greater Foster Creek Region and contingent resources on recently acquired oil sands assets in Alberta.
- Proved light and medium oil reserves remained unchanged, while proved heavy oil reserves increased approximately 5% due to the ongoing expansion of the waterflood and polymer injection program at Pelican Lake. Natural gas reserves declined about 21% compared with 2011 as Cenovus continued to redirect capital to its oil assets. As expected, this has resulted in natural gas production outpacing reserves additions. Lower natural gas prices and the divestiture of a non-core property early in 2012 also contributed to lower natural gas reserves.

- Cenovus's 2012 proved finding and development (F&D) costs, excluding changes in future development costs, were a competitive $9.04/BOE, up from $5.96/BOE in 2011 as capital spending increased and reserves additions decreased somewhat compared with 2011. The three-year average F&D costs were $6.10/BOE, excluding changes in future development costs.
- Cenovus achieved production replacement of nearly 350% in 2012.
- The overall proved reserves life index is approximately 23 years, a 5% increase compared with 2011. The magnitude of the company's bitumen assets is significant with a bitumen proved reserves life index of 52 years, down 13% due to the company's rapidly increasing bitumen production. The conventional oil and NGLs proved reserves life is 12 years.

Proved reserves reconciliation

(Before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Start of 2012	1,455	175	115	1,203
Extensions & improved recovery	265	17	13	29
Technical revisions	30	6	-2	51
Economic factors	-	-	-	-58
Acquisitions	-	-	1	1
Divestitures	-	-	-	-59
Production[1]	-33	-14	-12	-212
End of 2012	1,717	184	115	955
% Change	18	5	-	-21
Developed	185	122	93	949
Undeveloped	1,532	62	22	6
Total proved	1,717	184	115	955
Total probable	676	105	56	338
Total proved plus probable	2,393	289	171	1,293

[1] Production used for the reserves reconciliation differs from reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production. See the Advisory – Oil and Gas Information for more information about royalty interest production.

Proved reserves costs[1]			
(Before royalties)	**2012**	2011	3 Year
Capital Investment ($ millions)			
Finding and Development	**3,013**	2,175	6,562
Finding, Development and Acquisitions	**3,127**	2,244	6,793
Proved Reserves Additions[2] (MMBOE)			
Finding and Development	**333**	366	1,075
Finding, Development and Acquisitions	**334**	366	1,076
Proved Reserves Costs[2] ($/BOE)			
Finding and Development[3]	**9.04**	5.96	6.10
Finding, Development and Acquisitions[4]	**9.36**	6.14	6.31

[1] Finding and Development Cost calculations presented in the table do not include changes in future development costs. See the Advisory - Finding and Development Costs - for a full description of the methods used to calculate Finding and Development Costs which include the change in future development costs.
[2] Reserves Additions for Finding and Development are calculated by summing technical revisions, extensions and improved recovery, discoveries and economic factors. Reserves Additions for Finding, Development and Acquisitions are calculated by summing Reserves Additions for Finding and Development and additions from acquisitions. See the Advisory – Oil and Gas Information.
[3] Finding and Development Costs without changes in future development costs is equal to Finding and Development Capital Investment divided by Finding and Development Reserves Additions.
[4] Finding, Development and Acquisitions without changes in future development costs is equal to Finding, Development and Acquisitions Capital Investment divided by Finding, Development and Acquisitions Reserves Additions.

Bitumen contingent resources			
(Before royalties)			
Economic Contingent Resources[1]	**Bitumen (billion bbls)**		
	2012	**2011**	**% Change**
Low Estimate	**7.1**	6.0	18
Best Estimate	**9.6**	8.2	17
High Estimate	**12.8**	10.8	19

[1] For the definition of contingent resources, economic contingent resources and low, best and high estimate and a description of the contingencies associated with Cenovus's economic contingent resources, please see the Advisory – Oil and Gas Information. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Financial

Dividend

The Cenovus Board of Directors has approved a 10% increase in the first quarter 2013 dividend to $0.242 per share, payable on March 28, 2013 to common shareholders of record as of March 15, 2013. Based on the February 13, 2013 closing share price on the Toronto Stock Exchange of $32.60, this represents an annualized yield of about 3%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to the dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging strategy

Cenovus's natural gas and crude oil hedging strategy helps it to achieve more predictability around cash flow and safeguard its capital program. The strategy allows the company to financially hedge up to 75% of this year's expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the two following years. The company has Board approval for fixed price hedges on as much as 50% of net liquids production this year and 25% of net liquids production for each of the following two years. In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 135 MMcf/d of natural gas is expected to be consumed at the company's SAGD and refinery operations, which is offset by the gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's financial hedge positions at December 31, 2012 include:

- approximately 10% or 18,500 bbls/d of expected oil production hedged for 2013 at an average Brent price of US$110.36/bbl and an additional 10% or 18,500 bbls/d at an average Brent price of C$111.72/bbl
- 166 MMcf/d or approximately 32% of expected natural gas production hedged for 2013 at an average NYMEX price of US$4.64/Mcf, plus internal usage of approximately 135 MMcf/d of natural gas
- no fixed price commodity hedges in place beyond 2013
- approximately 49,200 bbls/d of heavy crude exposure hedged for 2013 at an average WCS differential to WTI of US$20.74/bbl
- approximately 9,400 bbls/d of heavy crude exposure hedged for 2014 at an average WCS differential to WTI of US$20.13/bbl.

Financial highlights

- Cash flow in 2012 was more than $3.6 billion, or $4.80 per share diluted, compared with nearly $3.3 billion, or $4.32 per share diluted, a year earlier.
- Operating earnings in 2012 were $866 million, or $1.14 per share diluted, compared with $1.2 billion, or $1.64 per share diluted, for the same period last year.
- Earnings in 2012 reflected a non-cash goodwill impairment charge of approximately $0.52 per share related to the company's Suffield assets in southeast Alberta. This was primarily due to estimated declines in future natural gas prices.
- Cenovus had a realized after-tax hedging gain of $250 million in 2012. Cenovus received an average realized price, including hedging, of $67.16/bbl for its oil in 2012, compared with $69.99/bbl during 2011. The average realized price, including hedging, for natural gas in 2012 was $3.56/Mcf, compared with $4.52/Mcf in 2011.
- Cenovus recorded income tax expense of $783 million, giving the company an effective tax rate of 44%, a substantial increase from the 2011 effective rate of 33%. The increase is primarily due to the goodwill impairment, which is not deductible, and to a one-time tax charge related to a U.S. withholding tax of $68 million.
- Cenovus's net earnings for the year were $993 million compared with approximately $1.5 billion in 2011. Net earnings were negatively impacted by lower commodity prices, the non-cash goodwill impairment, increased depreciation, depletion and

amortization (DD&A) costs and lower unrealized after-tax risk management gains, partly offset by higher unrealized foreign exchange gains. The increased DD&A rates were due to higher future development costs associated with total proved reserves.

- Capital investment during the year was nearly $3.4 billion, as planned. That was a 24% increase from $2.7 billion in 2011 as the company continued to advance development of its oil opportunities.
- General and administrative (G&A) expenses were $352 million in 2012, which was less than the company's corporate guidance for the year. G&A expenses were 19% higher in 2012, compared with 2011, primarily due to increases in staffing, salaries and benefits, long-term incentive expense and office costs related to the continued growth of the company.
- Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At December 31, 2012, the company's debt to capitalization ratio was 32% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.1 times.

Earnings reconciliation summary

(for the period ended December 31) ($ millions, except per share amounts)	**2012 Q4**	**2011 Q4**	**2012 Full Year**	**2011 Full Year**
Net earnings				
Add back losses & deduct gains:	**-118**	266	**993**	1,478
Per share diluted	**-0.16**	0.35	**1.31**	1.95
Unrealized mark-to-market hedging gain/loss, after-tax	**87**	-180	**43**	134
Non-operating foreign exchange gain/loss, after-tax	**-16**	25	**84**	14
Divestiture gain/loss, after-tax	**-**	89	**-**	91
Operating earnings/loss	**-189**	332	**866**	1,239
Per share diluted	**-0.25**	0.44	**1.14**	1.64

Oil sands project schedule			
Project phase	**Regulatory status**	**First production target**	**Expected production capacity (bbls/d) gross**
Foster Creek[1] A – E			120,000
F	Approved	Q3-2014F	45,000[2]
G	Approved	2015F	40,000
H	Approved	2016F	40,000
J	Submit 2013F	2019F	50,000
Future optimization			15,000
Total capacity			310,000
Christina Lake[1] A - D			98,000
E	Approved	Q3-2013F	40,000
F	Approved	2016F	50,000
G	Approved	2017F	50,000
H	Submit 2013F	2019F	50,000
Future optimization			12,000
Total capacity			300,000
Narrows Lake[1]			
A	Approved	2017F	45,000
B-C	Approved	TBD	85,000
Total Capacity			130,000
Grand Rapids	Submitted Q4-2011	2017F	180,000
Telephone Lake[3]	Submitted Q4-2011	TBD	90,000

[1] Properties 50% owned by ConocoPhillips. Certain phases may be subject to partner approval.
[2] Includes 5,000 bbls/d gross expected to be submitted to the regulator in 2013.
[3] Projected total capacity of more than 300,000 bbls/d.

Conference call today

9:00 a.m. Mountain Time (11:00 a.m. Eastern Time)

Cenovus will host a conference call today, February 14, 2013, starting at 9:00 a.m. MT (11:00 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 12:00 p.m. MT on February 14, 2013, until midnight February 21, 2013, by dialing 855-859-2056 or 416-849-0833 and entering conference passcode 87391969. A live audio webcast of the conference call will also be available via www.cenovus.com. The webcast will be archived for approximately 90 days.

ADVISORY

FINANCIAL INFORMATION

Basis of Presentation Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS).

Non-GAAP Measures This news release contains references to non-GAAP measures as follows:

- Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains, less realized losses on risk management activities and is used to provide a consistent measure of the cash generating performance of the company's assets and improves the comparability of Cenovus's underlying financial performance between periods.
- Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim and annual consolidated financial statements.
- Operating earnings is defined as Net Earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. Management views operating earnings as a better measure of performance than net earnings because the excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Free cash flow is defined as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.

- Debt to capitalization and debt to adjusted EBITDA are two ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion, excluding any amounts with respect to the partnership contribution payable and receivable. Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Adjusted EBITDA is defined as adjusted earnings before interest income, finance costs, income taxes, depreciation, depletion and amortization, exploration expense, unrealized gain or loss on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss, calculated on a trailing 12-month basis.

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. For further information, refer to Cenovus's most recent Management's Discussion & Analysis (MD&A) available at www.cenovus.com.

OIL AND GAS INFORMATION

The estimates of reserves and resources data and related information were prepared effective December 31, 2012 by independent qualified reserves evaluators ("IQREs") and are presented using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2013 price forecast. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalties volumes presented in the reserves reconciliation (i) do not include reserves associated with this production and (ii) the production differs from other publicly reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production.

Resources Terminology The estimates of bitumen contingent resources were prepared by McDaniel, an IQRE, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

- Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The McDaniel estimates of contingent resources have not been adjusted for risk based on the chance of development.
- Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

- Economic contingent 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 resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.
- Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican. Further information in respect of contingencies faced in these four regions is included in our Annual Information Form.
- Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

Barrels of Oil Equivalent Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

Finding and Development Costs Finding and development costs disclosed in this news release and used for calculating our recycle ratio do not include the change in estimated future development costs. Cenovus uses finding and development costs without changes in estimated future development costs as an indicator of relative performance to be consistent with the methodology accepted within the oil and gas industry.

Finding and development costs for *proved reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $25.48/BOE for the year ended December 31, 2012, $13.99/BOE for the year ended December 31, 2011 and averaged $16.35/BOE for the three years ended December 31, 2012. Finding and development costs for *proved plus probable reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $20.04/BOE for the year ended December 31, 2012, $10.69/BOE for the year ended December 31, 2011 and averaged $14.27/BOE for the three years ended December 31, 2012. These finding and development costs were calculated by dividing the sum of exploration costs, development costs and changes in future development costs in the particular period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period and the change during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

Net Asset Value With respect to the particular year being valued, the net asset value (NAV) disclosed herein is based on the number of issued and outstanding Cenovus shares as at December 31 as reported in our Annual Information Form and Form 40-F, plus the total dilutive effect of Cenovus shares related to stock option programs or other contracts as disclosed in the "Per Share Amounts" note to our annual Consolidated Financial Statements. We calculate NAV as an average of (i) our average trading price for the month of December, (ii) an average of net asset values published by external analysts in December following the announcement of our budget forecast, and (iii) an average of two net asset values based primarily on discounted cash flows of independently evaluated reserves, resources and refining data and using internal corporate costs, with one based on constant prices and costs and one based on forecast prices and costs.

FORWARD-LOOKING INFORMATION

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

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

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

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see “Risk Factors” in our most recent Annual Information Form/Form 40-F, “Risk Management” in our current MD&A and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and our website at www.cenovus.com.

TM denotes a trademark of Cenovus Energy Inc.

Cenovus Energy Inc.

Cenovus Energy Inc. is a Canadian integrated oil company. It is committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. 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. The company also has 50% ownership in two U.S.

refineries. Cenovus shares trade under the symbol CVE, and are listed on the Toronto and New York stock exchanges. Its enterprise value is approximately $30 billion. For more information, visit www.cenovus.com.

Find Cenovus on Facebook, Twitter, Linkedin and YouTube.

CENOVUS CONTACTS:

Investors:
Paul Gagne
Specialist, Investor Relations
403-766-7045

Bill Stait
Senior Analyst, Investor Relations
403-766-6348

Graham Ingram
Senior Analyst, Investor Relations
403-766-2849

Media:
Rhona DelFrari
Director, Media Relations
403-766-4740

Brett Harris
Senior Advisor, Media Relations
403-766-3420

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended December 31,
($ millions, except per share amounts)

	Notes	Three Months Ended 2012	Three Months Ended 2011	Twelve Months Ended 2012	Twelve Months Ended 2011
Revenues	1				
Gross sales		**3,802**	4,480	**17,229**	16,185
Less: Royalties		**78**	151	**387**	489
		3,724	4,329	**16,842**	15,696
Expenses	1				
Purchased product		**1,888**	2,531	**9,223**	9,090
Transportation and blending		**475**	396	**1,798**	1,369
Operating		**481**	386	**1,682**	1,406
Production and mineral taxes		**9**	9	**37**	36
(Gain) loss on risk management	19	**(209)**	230	**(393)**	(248)
Depreciation, depletion and amortization	11	**409**	383	**1,585**	1,295
Goodwill impairment	12	**393**	-	**393**	-
Exploration expense	10	**-**	-	**68**	-
General and administrative		**98**	89	**352**	295
Finance costs	3	**111**	112	**455**	447
Interest income	4	**(25)**	(30)	**(109)**	(124)
Foreign exchange (gain) loss, net	5	**22**	(30)	**(20)**	26
(Gain) loss on divestiture of assets		**-**	(104)	**-**	(107)
Other (income) loss, net		**(1)**	3	**(5)**	4
Earnings Before Income Tax		**73**	354	**1,776**	2,207
Income tax expense	6	**191**	88	**783**	729
Net Earnings (Loss)		**(118)**	266	**993**	1,478
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment		**12**	(25)	**(24)**	48
Comprehensive Income (Loss)		**(106)**	241	**969**	1,526
Net Earnings (Loss) per Common Share	7				
Basic		**$ (0.16)**	$ 0.35	**$ 1.31**	$ 1.96
Diluted		**$ (0.16)**	$ 0.35	**$ 1.31**	$ 1.95

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
($ millions)

	Notes	December 31, 2012	December 31, 2011
Assets			
Current Assets			
Cash and cash equivalents		**1,160**	495
Accounts receivable and accrued revenues		**1,464**	1,405
Current portion of Partnership Contribution Receivable		**384**	372
Inventories	8	**1,288**	1,291
Risk management	19	**283**	232
Assets held for sale	9	**-**	116
Current Assets		**4,579**	3,911
Exploration and Evaluation Assets	1,10	**1,285**	880
Property, Plant and Equipment, net	1,11	**16,152**	14,324
Partnership Contribution Receivable		**1,398**	1,822
Risk Management	19	**5**	52
Income Tax Receivable		**-**	29
Other Assets		**58**	44
Goodwill	1,12	**739**	1,132
Total Assets		**24,216**	22,194
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**2,650**	2,579
Income tax payable		**217**	329
Current portion of Partnership Contribution Payable		**386**	372
Risk management	19	**17**	54
Liabilities related to assets held for sale	9	**-**	54
Current Liabilities		**3,270**	3,388
Long-Term Debt	13	**4,679**	3,527
Partnership Contribution Payable		**1,426**	1,853
Risk Management	19	**1**	14
Decommissioning Liabilities	14	**2,315**	1,777
Other Liabilities		**151**	128
Deferred Income Taxes		**2,568**	2,101
Total Liabilities		**14,410**	12,788
Shareholders' Equity		**9,806**	9,406
Total Liabilities and Shareholders' Equity		**24,216**	22,194

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital (Note 15)	Paid in Surplus	Retained Earnings	AOCI*	Total
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 (loss) for the period	-	-	1,478	48	1,526
Common shares issued under option plans	64	-	-	-	64
Stock-based compensation expense	-	24	-	-	24
Dividends on common shares	-	-	(603)	-	(603)
Balance as at December 31, 2011	3,780	4,107	1,400	119	9,406
Net earnings	-	-	993	-	993
Other comprehensive income (loss)	-	-	-	(24)	(24)
Total comprehensive income (loss) for the period	-	-	993	(24)	969
Common shares issued under option plans	49	-	-	-	49
Stock-based compensation expense	-	47	-	-	47
Dividends on common shares	-	-	(665)	-	(665)
Balance as at December 31, 2012	**3,829**	**4,154**	**1,728**	**95**	**9,806**

* Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended December 31,
($ millions)

	Notes	Three Months Ended 2012	2011	Twelve Months Ended 2012	2011
Operating Activities					
Net earnings (loss)		**(118)**	266	**993**	1,478
Depreciation, depletion and amortization		**409**	383	**1,585**	1,295
Goodwill impairment		**393**	-	**393**	-
Exploration expense		**-**	-	**68**	-
Deferred income taxes	6	**66**	24	**474**	575
Cash tax on divestiture of assets		**-**	13	**-**	13
Unrealized (gain) loss on risk management	19	**(117)**	242	**(57)**	(180)
Unrealized foreign exchange (gain) loss	5	**12**	(43)	**(70)**	(42)
(Gain) loss on divestiture of assets		**-**	(104)	**-**	(107)
Unwinding of discount on decommissioning liabilities	3,14	**22**	19	**86**	75
Other		**30**	51	**171**	169
		697	851	**3,643**	3,276
Net change in other assets and liabilities		**(42)**	(20)	**(113)**	(82)
Net change in non-cash working capital		**103**	121	**(110)**	79
Cash From Operating Activities		**758**	952	**3,420**	3,273
Investing Activities					
Capital expenditures – exploration and evaluation assets	10	**(203)**	(186)	**(654)**	(527)
Capital expenditures – property, plant and equipment	11	**(812)**	(767)	**(2,795)**	(2,265)
Proceeds from divestiture of assets		**11**	165	**76**	173
Cash tax on divestiture of assets		**-**	(13)	**-**	(13)
Net change in investments and other		**(3)**	(7)	**(13)**	(28)
Net change in non-cash working capital		**32**	137	**50**	130
Cash (Used in) Investing Activities		**(975)**	(671)	**(3,336)**	(2,530)
Net Cash Provided (Used) before Financing Activities		**(217)**	281	**84**	743
Financing Activities					
Net issuance (repayment) of short-term borrowings		**-**	(6)	**3**	(9)
Issuance of long-term debt		**-**	-	**1,219**	-
Proceeds on issuance of common shares		**2**	4	**37**	48
Dividends paid on common shares	7	**(167)**	(151)	**(665)**	(603)
Other		**(3)**	9	**(2)**	6
Cash From (Used in) Financing Activities		**(168)**	(144)	**592**	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**2**	-	**(11)**	10
Increase (Decrease) in Cash and Cash Equivalents		**(383)**	137	**665**	195
Cash and Cash Equivalents, Beginning of Period		**1,543**	358	**495**	300
Cash and Cash Equivalents, End of Period		**1,160**	495	**1,160**	495

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

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

The Company's reportable segments are as follows:

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

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

- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information (For the Three Months Ended December 31)

	Oil Sands		Conventional		Refining and Marketing	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**1,062**	951	**522**	611	**2,336**	2,927
Less: Royalties	**40**	94	**38**	57	**-**	-
	1,022	857	**484**	554	**2,336**	2,927
Expenses						
Purchased product	**-**	-	**-**	-	**2,006**	2,540
Transportation and blending	**441**	362	**34**	34	**-**	-
Operating	**152**	117	**131**	137	**198**	132
Production and mineral taxes	**-**	-	**9**	9	**-**	-
(Gain) loss on risk management	**(45)**	21	**(57)**	(50)	**10**	17
Operating Cash Flow	**474**	357	**367**	424	**122**	238
Depreciation, depletion and amortization	**130**	93	**225**	203	**37**	76
Goodwill impairment	**-**	-	**393**	-	**-**	-
Exploration expense	**-**	-	**-**	-	**-**	-
Segment Income (Loss)	**344**	264	**(251)**	221	**85**	162

	Corporate and Eliminations		Consolidated	
	2012	2011	**2012**	2011
Revenues				
Gross sales	**(118)**	(9)	**3,802**	4,480
Less: Royalties	**-**	-	**78**	151
	(118)	(9)	**3,724**	4,329
Expenses				
Purchased product	**(118)**	(9)	**1,888**	2,531
Transportation and blending	**-**	-	**475**	396
Operating	**-**	-	**481**	386
Production and mineral taxes	**-**	-	**9**	9
(Gain) loss on risk management	**(117)**	242	**(209)**	230
	117	(242)	**1,080**	777
Depreciation, depletion and amortization	**17**	11	**409**	383
Goodwill impairment	**-**	-	**393**	-
Exploration expense	**-**	-	**-**	-
Segment Income (Loss)	**100**	(253)	**278**	394
General and administrative	**98**	89	**98**	89
Finance costs	**111**	112	**111**	112
Interest income	**(25)**	(30)	**(25)**	(30)
Foreign exchange (gain) loss, net	**22**	(30)	**22**	(30)
(Gain) loss on divestiture of assets	**-**	(104)	**-**	(104)
Other (income) loss, net	**(1)**	3	**(1)**	3
	205	40	**205**	40
Earnings Before Income Tax			**73**	354
Income tax expense			**191**	88
Net Earnings (Loss)			**(118)**	266

B) Financial Results by Upstream Product (For the Three Months Ended December 31)

Crude Oil and NGLs	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	1,043	931	372	416	1,415	1,347
Less: Royalties	40	93	36	54	76	147
	1,003	838	336	362	1,339	1,200
Expenses						
Transportation and blending	440	361	30	26	470	387
Operating	143	108	70	69	213	177
Production and mineral taxes	-	-	10	8	10	8
(Gain) loss on risk management	(42)	26	(14)	13	(56)	39
Operating Cash Flow	462	343	240	246	702	589

Natural Gas	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	15	16	146	192	161	208
Less: Royalties	-	1	2	3	2	4
	15	15	144	189	159	204
Expenses						
Transportation and blending	1	1	4	8	5	9
Operating	7	7	60	67	67	74
Production and mineral taxes	-	-	(1)	1	(1)	1
(Gain) loss on risk management	(3)	(5)	(43)	(63)	(46)	(68)
Operating Cash Flow	10	12	124	176	134	188

Other	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	4	4	4	3	8	7
Less: Royalties	-	-	-	-	-	-
	4	4	4	3	8	7
Expenses						
Transportation and blending	-	-	-	-	-	-
Operating	2	2	1	1	3	3
Production and mineral taxes	-	-	-	-	-	-
(Gain) loss on risk management	-	-	-	-	-	-
Operating Cash Flow	2	2	3	2	5	4

Total Upstream	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	1,062	951	522	611	1,584	1,562
Less: Royalties	40	94	38	57	78	151
	1,022	857	484	554	1,506	1,411
Expenses						
Transportation and blending	441	362	34	34	475	396
Operating	152	117	131	137	283	254
Production and mineral taxes	-	-	9	9	9	9
(Gain) loss on risk management	(45)	21	(57)	(50)	(102)	(29)
Operating Cash Flow	474	357	367	424	841	781

C) Geographic Information (For the Three Months Ended December 31)

	Canada		United States		Consolidated	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**2,010**	2,101	**1,792**	2,379	**3,802**	4,480
Less: Royalties	**78**	151	**-**	-	**78**	151
	1,932	1,950	**1,792**	2,379	**3,724**	4,329
Expenses						
Purchased product	**418**	537	**1,470**	1,994	**1,888**	2,531
Transportation and blending	**475**	396	**-**	-	**475**	396
Operating	**288**	259	**193**	127	**481**	386
Production and mineral taxes	**9**	9	**-**	-	**9**	9
(Gain) loss on risk management	**(216)**	204	**7**	26	**(209)**	230
	958	545	**122**	232	**1,080**	777
Depreciation, depletion and amortization	**372**	307	**37**	76	**409**	383
Goodwill impairment	**393**	-	**-**	-	**393**	-
Exploration expense	**-**	-	**-**	-	**-**	-
Segment Income (Loss)	**193**	238	**85**	156	**278**	394

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.

D) Results of Operations – Segment and Operational Information (For the Twelve Months Ended December 31)

	Oil Sands		Conventional		Refining and Marketing	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**4,088**	3,291	**2,068**	2,328	**11,356**	10,625
Less: Royalties	**215**	284	**172**	205	**-**	-
	3,873	3,007	**1,896**	2,123	**11,356**	10,625
Expenses						
Purchased product	**-**	-	**-**	-	**9,506**	9,149
Transportation and blending	**1,653**	1,231	**145**	138	**-**	-
Operating	**584**	438	**513**	488	**587**	481
Production and mineral taxes	**-**	-	**37**	36	**-**	-
(Gain) loss on risk management	**(80)**	70	**(252)**	(152)	**(4)**	14
Operating Cash Flow	**1,716**	1,268	**1,453**	1,613	**1,267**	981
Depreciation, depletion and amortization	**482**	347	**905**	778	**146**	130
Goodwill impairment	**-**	-	**393**	-	**-**	-
Exploration expense	**-**	-	**68**	-	**-**	-
Segment Income (Loss)	**1,234**	921	**87**	835	**1,121**	851

	Corporate and Eliminations		Consolidated	
	2012	2011	**2012**	2011
Revenues				
Gross sales	**(283)**	(59)	**17,229**	16,185
Less: Royalties	**-**	-	**387**	489
	(283)	(59)	**16,842**	15,696
Expenses				
Purchased product	**(283)**	(59)	**9,223**	9,090
Transportation and blending	**-**	-	**1,798**	1,369
Operating	**(2)**	(1)	**1,682**	1,406
Production and mineral taxes	**-**	-	**37**	36
(Gain) loss on risk management	**(57)**	(180)	**(393)**	(248)
	59	181	**4,495**	4,043
Depreciation, depletion and amortization	**52**	40	**1,585**	1,295
Goodwill impairment	**-**	-	**393**	-
Exploration expense	**-**	-	**68**	-
Segment Income (Loss)	**7**	141	**2,449**	2,748
General and administrative	**352**	295	**352**	295
Finance costs	**455**	447	**455**	447
Interest income	**(109)**	(124)	**(109)**	(124)
Foreign exchange (gain) loss, net	**(20)**	26	**(20)**	26
(Gain) loss on divestiture of assets	**-**	(107)	**-**	(107)
Other (income) loss, net	**(5)**	4	**(5)**	4
	673	541	**673**	541
Earnings Before Income Tax			**1,776**	2,207
Income tax expense			**783**	729
Net Earnings			**993**	1,478

E) Financial Results by Upstream Product (For the Twelve Months Ended December 31)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**4,037**	3,217	**1,559**	1,492	**5,596**	4,709
Less: Royalties	**215**	282	**166**	193	**381**	475
	3,822	2,935	**1,393**	1,299	**5,215**	4,234
Expenses						
Transportation and blending	**1,651**	1,229	**126**	104	**1,777**	1,333
Operating	**548**	409	**294**	244	**842**	653
Production and mineral taxes	**-**	-	**34**	27	**34**	27
(Gain) loss on risk management	**(62)**	87	**(23)**	43	**(85)**	130
Operating Cash Flow	**1,685**	1,210	**962**	881	**2,647**	2,091

	Natural Gas					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**40**	63	**496**	825	**536**	888
Less: Royalties	**-**	2	**6**	12	**6**	14
	40	61	**490**	813	**530**	874
Expenses						
Transportation and blending	**2**	2	**19**	34	**21**	36
Operating	**25**	24	**215**	240	**240**	264
Production and mineral taxes	**-**	-	**3**	9	**3**	9
(Gain) loss on risk management	**(18)**	(17)	**(229)**	(195)	**(247)**	(212)
Operating Cash Flow	**31**	52	**482**	725	**513**	777

	Other					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**11**	11	**13**	11	**24**	22
Less: Royalties	**-**	-	**-**	-	**-**	-
	11	11	**13**	11	**24**	22
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**11**	5	**4**	4	**15**	9
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**-**	6	**9**	7	**9**	13

	Total Upstream					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**4,088**	3,291	**2,068**	2,328	**6,156**	5,619
Less: Royalties	**215**	284	**172**	205	**387**	489
	3,873	3,007	**1,896**	2,123	**5,769**	5,130
Expenses						
Transportation and blending	**1,653**	1,231	**145**	138	**1,798**	1,369
Operating	**584**	438	**513**	488	**1,097**	926
Production and mineral taxes	**-**	-	**37**	36	**37**	36
(Gain) loss on risk management	**(80)**	70	**(252)**	(152)	**(332)**	(82)
Operating Cash Flow	**1,716**	1,268	**1,453**	1,613	**3,169**	2,881

F) Geographic Information (For the Twelve Months Ended December 31)

	Canada		United States		Consolidated	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross sales	**8,069**	7,513	**9,160**	8,672	**17,229**	16,185
Less: Royalties	**387**	489	**-**	-	**387**	489
	7,682	7,024	**9,160**	8,672	**16,842**	15,696
Expenses						
Purchased product	**1,884**	1,867	**7,339**	7,223	**9,223**	9,090
Transportation and blending	**1,798**	1,369	**-**	-	**1,798**	1,369
Operating	**1,118**	947	**564**	459	**1,682**	1,406
Production and mineral taxes	**37**	36	**-**	-	**37**	36
(Gain) loss on risk management	**(385)**	(255)	**(8)**	7	**(393)**	(248)
	3,230	3,060	**1,265**	983	**4,495**	4,043
Depreciation, depletion and amortization	**1,439**	1,165	**146**	130	**1,585**	1,295
Goodwill impairment	**393**	-	**-**	-	**393**	-
Exploration expense	**68**	-	**-**	-	**68**	-
Segment Income (Loss)	**1,330**	1,895	**1,119**	853	**2,449**	2,748

G) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

By Segment

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

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

By Geographic Region

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

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

H) Capital Expenditures

For the period ended December 31,	Three Months Ended 2012	Three Months Ended 2011	Twelve Months Ended 2012	Twelve Months Ended 2011
Capital				
Oil Sands	**605**	465	**2,211**	1,415
Conventional	**257**	330	**848**	788
Refining and Marketing	**58**	73	**118**	393
Corporate	**58**	35	**191**	127
	978	903	**3,368**	2,723
Acquisition Capital				
Oil Sands [2]	**67**	40	**69**	44
Conventional	**3**	10	**45**	25
Corporate	**-**	(1)	**-**	2
Total [1]	**1,048**	952	**3,482**	2,794

1. Includes expenditures on property, plant and equipment and exploration & evaluation assets.
2. 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these interim 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 interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34") and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2011 except for income taxes on earnings in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. The disclosures provided below are incremental to those included with the annual Consolidated Financial Statements. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective February 13, 2013.

3. FINANCE COSTS

For the period ended December 31,	Three Months Ended 2012	2011	Twelve Months Ended 2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	**64**	53	**230**	213
Interest Expense – Partnership Contribution Payable	**27**	34	**118**	138
Unwinding of Discount on Decommissioning Liabilities	**22**	19	**86**	75
Other	**(2)**	6	**21**	21
	111	112	**455**	447

4. INTEREST INCOME

For the period ended December 31,	Three Months Ended 2012	2011	Twelve Months Ended 2012	2011
Interest Income – Partnership Contribution Receivable	**(23)**	(29)	**(102)**	(120)
Other	**(2)**	(1)	**(7)**	(4)
	(25)	(30)	**(109)**	(124)

5. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended December 31,	Three Months Ended 2012	2011	Twelve Months Ended 2012	2011
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	**53**	(77)	**(69)**	78
U.S. dollar Partnership Contribution Receivable issued from Canada	**(37)**	37	**(15)**	(107)
Other	**(4)**	(3)	**14**	(13)
Unrealized Foreign Exchange (Gain) Loss	**12**	(43)	**(70)**	(42)
Realized Foreign Exchange (Gain) Loss	**10**	13	**50**	68
	22	(30)	**(20)**	26

6. INCOME TAXES

The provision for income taxes is as follows:

For the period ended December 31,	Three Months Ended 2012	2011	Twelve Months Ended 2012	2011
Current Tax				
Canada	**49**	62	**188**	150
United States [1]	**76**	2	**121**	4
Total Current Tax	**125**	64	**309**	154
Deferred Tax	**66**	24	**474**	575
	191	88	**783**	729

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

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

For the years ended December 31,	2012	2011
Earnings Before Income Tax	**1,776**	2,207
Canadian Statutory Rate	**25.2%**	26.7%
Expected Income Tax	**448**	589
Effect of Taxes Resulting from:		
Foreign tax rate differential	**146**	82
Non-deductible stock-based compensation	**10**	18
Multi-jurisdictional financing	**(27)**	(50)
Foreign exchange gains (losses) not included in net earnings	**14**	(9)
Non-taxable capital (gains) losses	**(7)**	(8)
Recognition of capital losses	**(22)**	26
Adjustments arising from prior year tax filings	**33**	31
Withholding tax on foreign dividend	**68**	-
Goodwill impairment	**99**	-
Other	**21**	50
	783	729
Effective Tax Rate	**44.1%**	33.0%

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

7. PER SHARE AMOUNTS

A) Net Earnings per Share

For the three months ended ($ millions, except earnings per share)	**December 31, 2012**			December 31, 2011		
	Net Earnings	**Shares**	**Earnings per Share**	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	**(118)**	**755.8**	**$(0.16)**	266	754.4	$0.35
Dilutive effect of Cenovus TSARs	**-**	**2.5**		-	2.7	
Net earnings per share – diluted	**(118)**	**758.3**	**$(0.16)**	266	757.1	$0.35

For the twelve months ended ($ millions, except earnings per share)	**December 31, 2012**			December 31, 2011		
	Net Earnings	**Shares**	**Earnings per Share**	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	**993**	**755.6**	**$1.31**	1,478	754.0	$1.96
Dilutive effect of Cenovus TSARs	**-**	**2.9**		-	3.7	
Net earnings per share – diluted	**993**	**758.5**	**$1.31**	1,478	757.7	$1.95

B) Dividends per Share

The Company paid dividends of $665 million, $0.88 per share, for the twelve months ended December 31, 2012 (December 31, 2011 – $603 million, $0.80 per share).

The Cenovus Board of Directors declared a first quarter dividend of $0.242 per share, payable on March 28, 2013, to common shareholders of record as of March 15, 2013.

8. INVENTORIES

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

9. ASSETS AND LIABILITIES HELD FOR SALE

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

As at	December 31, 2012	December 31, 2011
Assets Held for Sale		
Property, plant and equipment	**-**	116
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	**-**	54

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

10. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at December 31, 2010	713
Additions	527
Transfers to property, plant and equipment (Note 11)	(356)
Divestitures	(3)
Change in decommissioning liabilities	(1)
As at December 31, 2011	880
Additions [1]	687
Transfers to property, plant and equipment (Note 11)	(218)
Exploration expense	(68)
Divestitures	(11)
Change in decommissioning liabilities	15
As at December 31, 2012	**1,285**

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

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

Additions to E&E assets for the year ended December 31, 2012 include $37 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – $15 million). Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized for the years ended December 31, 2012 and 2011.

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

Impairment

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

11. PROPERTY, PLANT AND EQUIPMENT, NET

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

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

Additions to development and production assets include internal costs directly related to the development and construction of oil and gas properties of $161 million for the year ended December 31, 2012 (December 31, 2011 – $125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the years ended December 31, 2012 and 2011.

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

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

Impairment

The impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income. There were no impairment losses or impairment reversals recorded for the year ended December 31, 2012 (December 31, 2011 – $47 million). The impairment loss recorded in 2011 was related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations and an impairment on non-core natural gas assets that were reclassified as held for sale (Note 9).

12. GOODWILL

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

There were no additions to goodwill during 2012 or 2011.

Impairment Test for Cash-Generating Units Containing Goodwill

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

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

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

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

Oil and natural gas prices

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

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

Discount rate

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

There was no impairment of goodwill in 2011 or 2010.

Sensitivities

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

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

13. LONG-TERM DEBT

As at	December 31, 2012	December 31, 2011
Revolving term debt [1]	-	-
U.S. Dollar Denominated Unsecured Notes	4,726	3,559
Total Debt Principal	4,726	3,559
Debt Discounts and Transaction Costs	(47)	(32)
	4,679	3,527

1. Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

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

On May 24, 2012, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from, time to time, in one or more offerings. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On June 6, 2012, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies, from time to time, in one or more offerings. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, US$750 million remains under this U.S. base shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 17, 2012, Cenovus completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under the Company's U.S. base shelf prospectus. The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness. The unsecured notes issued are as follows:

	US$ Principal Amount	December 31, 2012
3.00% due August 15, 2022	**500**	**498**
4.45% due September 15, 2042	**750**	**746**
	1,250	**1,244**

In September 2012, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and slightly reducing both the standby fees required to maintain the facility as well as the cost of future borrowings.

14. DECOMMISSIONING LIABILITIES

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

As at	December 31, 2012	December 31, 2011
Decommissioning Liabilities, Beginning of Year	**1,777**	1,399
Liabilities incurred	**99**	49
Liabilities settled	**(66)**	(56)
Liabilities divested	**-**	-
Transfers and reclassifications	**3**	(55)
Change in estimated future cash flows	**144**	146
Change in discount rate	**273**	218
Unwinding of discount on decommissioning liabilities	**86**	75
Foreign currency translation	**(1)**	1
Decommissioning Liabilities, End of Year	**2,315**	1,777

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.2 percent as at December 31, 2012 (December 31, 2011 – 4.8 percent).

15. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding

	December 31, 2012		December 31, 2011	
As at	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**754,499**	**3,780**	752,675	3,716
Common Shares Issued under Stock Option Plans	**1,344**	**49**	1,824	64
Outstanding, End of Year	**755,843**	**3,829**	754,499	3,780

There were no preferred shares outstanding as at December 31, 2012 (December 31, 2011 – nil).

As at December 31, 2012, there were 28 million (December 31, 2011 – 30 million) common shares available for future issuance under stock option plans.

16. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

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

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus Replacement TSARs are measured against the Cenovus common share price while Encana Replacement TSARs are measured against the Encana common share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

As at December 31, 2012	Issued	Term (years)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Closing Share Price ($)	Units Outstanding (thousands)
Encana Replacement TSARs held by Cenovus Employees	Prior to Arrangement	**5**	**0.66**	**32.66**	**19.66**	**7,722**
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	**5**	**0.70**	**29.29**	**33.29**	**5,229**
TSARs	Prior to February 17, 2010	**5**	**0.72**	**29.28**	**33.29**	**6,225**
TSARs	On or After February 17, 2010	**7**	**4.20**	**26.71**	**33.29**	**5,026**
NSRs	On or After February 24, 2011	**7**	**5.85**	**37.52**	**33.29**	**15,074**

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

NSRs

The weighted average unit fair value of NSRs granted during the twelve months ended December 31, 2012 was $7.62 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	**1.37%**
Expected Dividend Yield	**2.31%**
Expected Volatility [1]	**28.62%**
Expected Life (Years)	**4.55**

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize the information related to the NSRs as at December 31, 2012:

As at December 31, 2012 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**5,809**	**36.95**
Granted	**9,665**	**37.87**
Exercised for common shares	**(5)**	**33.99**
Forfeited	**(395)**	**37.56**
Outstanding, End of Year	**15,074**	**37.52**
Exercisable, End of Year	**1,700**	**36.98**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $35.28.

	Outstanding NSRs (thousands of units)		
As at December 31, 2012 Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
30.00 to 39.99	**15,074**	**5.85**	**37.52**

As at December 31, 2012 Range of Exercise Price ($)	Exercisable NSRs (thousands of units) NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	**1,700**	**36.98**

TSARs Held by Cenovus Employees

The Company has recorded a liability of $64 million as at December 31, 2012 (December 31, 2011 – $90 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated as at December 31, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	**1.28%**
Expected Dividend Yield	**2.58%**
Expected Volatility [1]	**27.80%**
Cenovus's Common Share Price	**$33.29**

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at December 31, 2012 was $45 million (December 31, 2011 – $43 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	9,391	5,530	**14,921**	**28.12**
Granted	-	-	**-**	**-**
Exercised for cash payment	(937)	(1,057)	**(1,994)**	**28.52**
Exercised as options for common shares	(683)	(641)	**(1,324)**	**27.77**
Forfeited	(134)	(207)	**(341)**	**26.77**
Expired	(11)	-	**(11)**	**30.85**
Outstanding, End of Year	**7,626**	**3,625**	**11,251**	**28.13**
Exercisable, End of Year	**5,369**	**3,625**	**8,994**	**28.46**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.73.

As at December 31, 2012 Range of Exercise Price ($)	Outstanding TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
20.00 to 29.99	6,269	2,143	**8,412**	**2.88**	**26.38**
30.00 to 39.99	1,294	1,482	**2,776**	**0.48**	**33.10**
40.00 to 49.99	63	-	**63**	**0.45**	**43.29**
	7,626	**3,625**	**11,251**	**2.27**	**28.13**

As at December 31, 2012 Range of Exercise Price ($)	Exercisable TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	4,132	2,143	**6,275**	**26.35**
30.00 to 39.99	1,174	1,482	**2,656**	**33.11**
40.00 to 49.99	63	-	**63**	**43.29**
	5,369	**3,625**	**8,994**	**28.46**

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.

Encana Replacement TSARs Held by Cenovus Employees

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

The Company has recorded a liability of $1 million as at December 31, 2012 (December 31, 2011 – $1 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated as at December 31, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	**1.21%**
Expected Dividend Yield	**3.86%**
Expected Volatility [1]	**30.40%**
Encana's Common Share Price	**$19.66**

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

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees as at December 31, 2012 was $nil (December 31, 2011 – $nil).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	4,281	6,130	**10,411**	**31.97**
Exercised for cash payment	-	-	**-**	**-**
Exercised as options for Encana common shares	-	-	**-**	**-**
Forfeited	(112)	(333)	**(445)**	**31.04**
Expired	(1,008)	(1,236)	**(2,244)**	**29.79**
Outstanding, End of Year	**3,161**	**4,561**	**7,722**	**32.66**
Exercisable, End of Year	**3,161**	**4,561**	**7,722**	**32.66**

As at December 31, 2012 Range of Exercise Price ($)	Outstanding & Exercisable TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
20.00 to 29.99	1,564	2,510	**4,074**	**1.12**	**29.02**
30.00 to 39.99	1,465	2,051	**3,516**	**0.15**	**36.41**
40.00 to 49.99	130	-	**130**	**0.48**	**44.85**
50.00 to 59.99	2	-	**2**	**0.39**	**50.39**
	3,161	**4,561**	**7,722**	**0.66**	**32.66**

The closing price of Encana common shares on the TSX as at December 31, 2012 was $19.66.

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana'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 $35 million as at December 31, 2012 (December 31, 2011 – $83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated as at December 31, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	**1.21%**
Expected Dividend Yield	**2.58%**
Expected Volatility [1]	**27.80%**
Cenovus's Common Share Price	**$33.29**

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees as at December 31, 2012 was $22 million (December 31, 2011 – $32 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	3,935	5,751	**9,686**	**28.96**
Exercised for cash payment	(1,788)	(2,189)	**(3,977)**	**28.69**
Exercised as options for common shares	(8)	(12)	**(20)**	**26.64**
Forfeited	(84)	(314)	**(398)**	**27.67**
Expired	(30)	(32)	**(62)**	**27.67**
Outstanding, End of Year	**2,025**	**3,204**	**5,229**	**29.29**
Exercisable, End of Year	**2,025**	**3,204**	**5,229**	**29.29**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.72.

	Outstanding & Exercisable TSARs (thousands of units)				
As at December 31, 2012 Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
20.00 to 29.99	1,087	1,899	**2,986**	**1.12**	**26.27**
30.00 to 39.99	886	1,305	**2,191**	**0.14**	**33.08**
40.00 to 49.99	52	-	**52**	**0.44**	**42.70**
	2,025	**3,204**	**5,229**	**0.70**	**29.29**

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.

B) Performance Share Units

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

The Company has recorded a liability of $124 million as at December 31, 2012 (December 31, 2011 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares as at December 31, 2012. The intrinsic value of vested PSUs was $nil as at December 31, 2012 and December 31, 2011 as PSUs are paid out upon vesting.

The following table summarizes the information related to the PSUs held by Cenovus employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	**PSUs**
Outstanding, Beginning of Year	**2,623**
Granted	**2,704**
Cancelled	**(183)**
Units in Lieu of Dividends	**114**
Outstanding, End of Year	**5,258**

C) Deferred Share Units

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

The Company has recorded a liability of $36 million as at December 31, 2012 (December 31, 2011 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares as at December 31, 2012. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2012:

As at December 31, 2012 (thousands of units)	**DSUs**
Outstanding, Beginning of Year	**1,042**
Granted to Directors	**64**
Granted from Annual Bonus Awards	**22**
Units in Lieu of Dividends	**30**
Exercised	**(74)**
Outstanding, End of Year	**1,084**

D) Total Stock-Based Compensation Expense (Recovery)

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

	Three Months Ended		**Twelve Months Ended**	
For the period ended December 31,	**2012**	2011	**2012**	2011
NSRs	**5**	5	**27**	16
TSARs held by Cenovus employees	**(1)**	13	**(1)**	24
Encana Replacement TSARs held by Cenovus employees	**(1)**	(1)	**-**	(8)
PSUs	**7**	8	**46**	27
DSUs	**(1)**	2	**3**	4
	9	27	**75**	63

17. INTEREST IN JOINT OPERATIONS

On January 2, 2007, Cenovus became a 50 percent partner in an integrated North American heavy oil business. The integrated business is structured through two joint arrangements. The upstream entity, FCCL Partnership, is involved in the development and production of crude oil and is jointly controlled with ConocoPhillips. The refining entity, WRB Refining LP, includes two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with Phillips 66.

Cenovus recognizes its share of the assets, liabilities, revenues and expenses (proportionately consolidates) these joint operations with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Cenovus's Consolidated Financial Statements include the following amounts related to these joint arrangements:

Statements of Earnings For the three months ended December 31,	FCCL Partnership [1] **2012**	 2011	WRB Refining LP [1] **2012**	 2011
Revenues	**847**	702	**1,792**	2,379
Expenses				
Purchased product	**-**	-	**1,470**	1,994
Operating, transportation and blending and realized (gain)/loss on risk management	**519**	406	**202**	144
Operating Cash Flow	**328**	296	**120**	241
Depreciation, depletion and amortization	**86**	60	**35**	76
Other expenses (income)	**(32)**	43	**(3)**	10
Net Earnings (Loss)	**274**	193	**88**	155

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.

Statements of Earnings For the twelve months ended December 31,	FCCL Partnership [1] **2012**	 2011	WRB Refining LP [1] **2012**	 2011
Revenues	**3,132**	2,364	**9,160**	8,672
Expenses				
Purchased product	**-**	-	**7,339**	7,223
Operating, transportation and blending and realized (gain)/loss on risk management	**1,944**	1,397	**552**	473
Operating Cash Flow	**1,188**	967	**1,269**	976
Depreciation, depletion and amortization	**303**	205	**135**	130
Other expenses (income)	**1**	(136)	**4**	(4)
Net Earnings (Loss)	**884**	898	**1,130**	850

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.

As at	FCCL Partnership **December 31, 2012**	 December 31, 2011	WRB Refining LP **December 31, 2012**	 December 31, 2011
Cash and Cash Equivalents	**388**	145	**172**	166
Other Current Assets	**761**	792	**1,111**	1,236
Long-term Assets	**7,599**	6,864	**3,087**	3,188
Current Liabilities	**350**	317	**566**	759
Long-term Liabilities	**137**	83	**58**	73

18. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

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

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at	December 31, 2012	December 31, 2011
Long-Term Debt	**4,679**	3,527
Debt	**4,679**	3,527
Shareholders' Equity	**9,806**	9,406
Capitalization	**14,485**	12,933
Debt to Capitalization	**32%**	27%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

As at	December 31, 2012	December 31, 2011
Debt	**4,679**	3,527
Net Earnings	**993**	1,478
Add (deduct):		
Finance costs	**455**	447
Interest income	**(109)**	(124)
Income tax expense	**783**	729
Depreciation, depletion and amortization	**1,585**	1,295
Goodwill impairment	**393**	-
Exploration expense	**68**	-
Unrealized (gain) loss on risk management	**(57)**	(180)
Foreign exchange (gain) loss, net	**(20)**	26
(Gain) loss on divestiture of assets	**-**	(107)
Other (income) loss, net	**(5)**	4
Adjusted EBITDA	**4,086**	3,568
Debt to Adjusted EBITDA	**1.1x**	1.0x

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.

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

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. 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, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of those instruments.

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

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

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on prices sourced from market data. As at December 31, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $4,679 million and the fair value was $5,582 million (December 31, 2011 carrying value – $3,527 million, fair value – $4,316 million).

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at	**December 31, 2012**	December 31, 2011
Risk Management Assets		
Current asset	**283**	232
Long-term asset	**5**	52
	288	284
Risk Management Liabilities		
Current liability	**17**	54
Long-term liability	**1**	14
	18	68
Net Risk Management Asset (Liability)	**270**	216

Summary of Unrealized Risk Management Positions

	December 31, 2012			December 31, 2011		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**221**	**16**	**205**	22	65	(43)
Natural Gas	**66**	**1**	**65**	247	3	244
Power	**1**	**1**	**-**	15	-	15
Total Fair Value	**288**	**18**	**270**	284	68	216

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	December 31, 2012	December 31, 2011
Prices actively quoted (Level 1)	**120**	226
Prices sourced from observable data or market corroboration (Level 2)	**150**	(10)
Total Fair Value	**270**	216

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

Net Fair Value of Commodity Price Positions

As at December 31, 2012	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price [1]	18,500 bbls/d	2013	US$110.36/bbl	**23**
Brent Fixed Price [1]	18,500 bbls/d	2013	$111.72/bbl	**33**
WCS Differential [2]	49,200 bbls/d	2013	US$(20.74)/bbl	**145**
WCS Differential [2]	9,400 bbls/d	2014	US$(20.13)/bbl	**5**
Other Financial Positions [3]				**(1)**
Crude Oil Fair Value Position				**205**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	**66**
Other Fixed Price Contracts [4]				**(1)**
Natural Gas Fair Value Position				**65**
Power Purchase Contracts				
Power Fair Value Position				**-**

1. Brent fixed price positions consist of both Brent fixed price swaps and WTI swaps converted to Brent.
2. Cenovus has entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.
3. Other financial positions are part of ongoing operations to market the Company's production.
4. Cenovus has entered into other fixed price contracts to protect against widening price differentials between production areas and various sales points.

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

	Three Months Ended		Twelve Months Ended	
For the period ended December 31,	**2012**	2011	**2012**	2011
REALIZED GAIN (LOSS) [1]				
Crude Oil	**55**	(39)	**81**	(135)
Natural Gas	**47**	67	**247**	210
Refining	**(11)**	(17)	**7**	(14)
Power	**1**	1	**1**	7
	92	12	**336**	68
UNREALIZED GAIN (LOSS) [2]				
Crude Oil	**145**	(312)	**247**	106
Natural Gas	**(32)**	76	**(176)**	38
Refining	**4**	(9)	**1**	7
Power	**-**	3	**(15)**	29
	117	(242)	**57**	180
Gain (Loss) on Risk Management	**209**	(230)	**393**	248

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

	2012		2011
For the period ended December 31,	**Fair Value**	**Total Unrealized Gain (Loss)**	**Total Unrealized Gain (Loss)**
Fair Value of Contracts, Beginning of Year	**216**		
Change in fair value of contracts in place at beginning of year and contracts entered into during the year	**393**	**393**	248
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	**(3)**	**-**	-
Fair value of contracts realized during the year	**(336)**	**(336)**	(68)
Fair Value of Contracts, End of Year	**270**	**57**	180

Commodity Price Sensitivities – Risk Management Positions

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

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude oil commodity price	± US$10 per bbl applied to Brent & WTI hedges	**(156)**	**156**
Crude oil differential price	± US$5 per bbl applied to differential hedges tied to production	**111**	**(111)**
Natural gas commodity price	± $1 per mcf applied to NYMEX natural gas hedges	**(55)**	**55**
Natural gas basis price	± $0.10 per mcf applied to natural gas basis hedges	**1**	**(1)**
Power commodity price	± $25 per MWHr applied to power hedge	**19**	**(19)**

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

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

Power – The Company has in place a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with large commercial counterparties, most of which have investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. At December 31, 2012 and 2011, substantially all of the Company's accounts receivable were current. As at December 31, 2012, 87 percent (December 31, 2011 – 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

As at December 31, 2012, Cenovus had two counterparties (December 31, 2011 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value. The majority of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within credit policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 18, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. As at December 31, 2012, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$750 million under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

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

	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,650	-	-	-	**2,650**
Risk Management Liabilities	17	1	-	-	**18**
Long-Term Debt [1]	254	1,263	432	7,051	**9,000**
Partnership Contribution Payable [1]	486	972	609	-	**2,067**
Other [1]	-	9	4	4	**17**

1. Principal and interest, including current portion, if any.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value of 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 5, 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. As at December 31, 2012, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (US$3,500 million as at December 31, 2011) and US$1,791 million related to the U.S. dollar Partnership Contribution Receivable (US$2,157 million as at December 31, 2011). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $30 million change in foreign exchange (gain) loss as at December 31, 2012 (December 31, 2011 – $13 million).

Interest Rate Risk

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

As at December 31, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (December 31, 2011 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

20. COMMITMENTS AND 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.

21. SUBSEQUENT EVENT

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**17,229**	**3,802**	4,462	4,279	4,686	16,185	4,480	3,989	4,085	3,631
Less: Royalties	**387**	**78**	122	65	122	489	151	131	76	131
Revenues	**16,842**	**3,724**	4,340	4,214	4,564	15,696	4,329	3,858	4,009	3,500
Operating Cash Flow										
Crude Oil and Natural Gas Liquids										
Foster Creek	**924**	**246**	227	223	228	780	213	194	222	151
Christina Lake	**343**	**118**	93	70	62	125	61	19	23	22
Pelican Lake	**418**	**98**	108	85	127	305	69	83	76	77
Conventional	**962**	**240**	227	228	267	881	246	209	218	208
Natural Gas	**513**	**134**	126	121	132	777	188	200	197	192
Other Upstream Operations	**9**	**5**	2	-	2	13	4	2	3	4
	3,169	**841**	783	727	818	2,881	781	707	739	654
Refining and Marketing	**1,267**	**122**	527	351	267	981	238	238	325	180
Operating Cash Flow [1]	**4,436**	**963**	1,310	1,078	1,085	3,862	1,019	945	1,064	834
Cash Flow Information										
Cash from Operating Activities	**3,420**	**758**	1,029	968	665	3,273	952	921	769	631
Deduct (Add back):										
Net change in other assets and liabilities	**(113)**	**(42)**	(19)	(20)	(32)	(82)	(20)	(17)	(16)	(29)
Net change in non-cash working capital	**(110)**	**103**	(69)	63	(207)	79	121	145	(154)	(33)
Cash Flow [2]	**3,643**	**697**	1,117	925	904	3,276	851	793	939	693
Per share - Basic	**4.82**	**0.92**	1.48	1.22	1.20	4.34	1.13	1.05	1.25	0.92
- Diluted	**4.80**	**0.92**	1.47	1.22	1.19	4.32	1.12	1.05	1.24	0.91
Operating Earnings [3]	**866**	**(189)**	432	283	340	1,239	332	303	395	209
Per share - Diluted	**1.14**	**(0.25)**	0.57	0.37	0.45	1.64	0.44	0.40	0.52	0.28
Net Earnings	**993**	**(118)**	289	396	426	1,478	266	510	655	47
Per share - Basic	**1.31**	**(0.16)**	0.38	0.52	0.56	1.96	0.35	0.68	0.87	0.06
- Diluted	**1.31**	**(0.16)**	0.38	0.52	0.56	1.95	0.35	0.67	0.86	0.06
Effective Tax Rates using										
Net Earnings	**44.1%**					33.0%				
Operating Earnings, excluding divestitures	**47.0%**					34.5%				
Canadian Statutory Rate	**25.2%**					26.7%				
U.S. Statutory Rate	**38.5%**					37.5%				
Foreign Exchange Rates (US$ per C$1)										
Average	**1.001**	**1.009**	1.005	0.990	0.999	1.012	0.978	1.020	1.033	1.015
Period end	**1.005**	**1.005**	1.017	0.981	1.001	0.983	0.983	0.963	1.037	1.029

(1) Operating Cash Flow is a non-GAAP measure defined as revenue less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities.

(2) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)	2012	2011
Debt to Capitalization [4], [5]	**32%**	27%
Debt to Adjusted EBITDA [5], [6]	**1.1x**	1.0x
Return on Capital Employed [7]	**9%**	13%
Return on Common Equity [8]	**10%**	17%

(4) Capitalization is a non-GAAP measure defined as Debt plus Shareholders' Equity.

(5) Debt includes the Company's short-term borrowings plus long-term debt, including the current portion of long-term debt.

(6) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.

(7) Calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average Shareholders' Equity plus average Debt.

(8) Calculated, on a trailing twelve-month basis, as net earnings divided by average Shareholders' Equity.

Financial Statistics (continued)

Common Share Information

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)										
Period end	**755.8**	**755.8**	755.8	755.7	755.6	754.5	754.5	754.3	754.1	753.9
Average - Basic	**755.6**	**755.8**	755.7	755.7	755.1	754.0	754.4	754.3	754.1	753.2
Average - Diluted	**758.5**	**758.3**	758.0	757.9	759.5	757.7	757.1	757.8	758.0	758.1
Price Range ($ per share)										
TSX - C$										
High	**39.64**	**35.69**	36.25	36.68	39.64	38.98	37.11	38.38	38.98	38.90
Low	**30.09**	**31.82**	30.37	30.09	33.24	28.85	28.85	29.87	31.73	31.15
Close	**33.29**	**33.29**	34.31	32.37	35.90	33.83	33.83	32.27	36.40	38.30
NYSE - US$										
High	**39.81**	**36.11**	37.31	37.26	39.81	40.73	37.35	40.61	40.73	40.06
Low	**28.83**	**31.74**	30.20	28.83	32.45	27.15	27.15	29.02	32.48	31.11
Close	**33.54**	**33.54**	34.85	31.80	35.94	33.20	33.20	30.71	37.66	39.38
Dividends Paid ($ per share)	**$ 0.88**	**$ 0.22**	$ 0.22	$ 0.22	$ 0.22	$ 0.80	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Share Volume Traded (millions)	**664.3**	**141.7**	152.6	192.6	177.4	873.7	213.3	239.8	215.9	204.7

Net Capital Investment *($ millions)*

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Oil Sands										
Foster Creek	**735**	**208**	199	169	159	429	139	110	77	103
Christina Lake	**579**	**167**	147	138	127	472	126	117	121	108
Total	**1,314**	**375**	346	307	286	901	265	227	198	211
Pelican Lake	**518**	**147**	128	104	139	317	132	70	31	84
Other Oil Sands	**379**	**83**	42	43	211	197	68	9	11	109
	2,211	**605**	516	454	636	1,415	465	306	240	404
Conventional	**848**	**257**	231	129	231	788	330	193	89	176
Refining and Marketing	**118**	**58**	38	24	(2)	393	73	101	117	102
Corporate	**191**	**58**	45	53	35	127	35	31	30	31
Capital Investment	**3,368**	**978**	830	660	900	2,723	903	631	476	713
Acquisitions [1]	**114**	**70**	8	28	8	71	49	1	2	19
Divestitures	**(76)**	**(11)**	-	1	(66)	(173)	(164)	-	(5)	(4)
Net Acquisition and Divestiture Activity	**38**	**59**	8	29	(58)	(102)	(115)	1	(3)	15
Net Capital Investment	**3,406**	**1,037**	838	689	842	2,621	788	632	473	728

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

Operating Statistics - Before Royalties

Upstream Production Volumes

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)										
Oil Sands - Heavy Oil										
Foster Creek	**57,833**	**59,059**	63,245	51,740	57,214	54,868	55,045	56,322	50,373	57,744
Christina Lake	**31,903**	**41,808**	32,380	28,577	24,733	11,665	19,531	10,067	7,880	9,084
Total	**89,736**	**100,867**	95,625	80,317	81,947	66,533	74,576	66,389	58,253	66,828
Pelican Lake	**22,552**	**23,507**	23,539	22,410	20,730	20,424	20,558	20,363	19,427	21,360
	112,288	**124,374**	119,164	102,727	102,677	86,957	95,134	86,752	77,680	88,188
Conventional Liquids										
Heavy Oil	**16,015**	**16,243**	15,492	15,703	16,624	15,657	15,512	15,305	15,378	16,447
Light and Medium Oil	**36,071**	**36,034**	35,695	36,149	36,411	30,524	32,530	30,399	27,617	31,539
Natural Gas Liquids [1]	**1,029**	**995**	999	987	1,138	1,101	1,097	1,040	1,087	1,181
Total Crude Oil and Natural Gas Liquids	**165,403**	**177,646**	171,350	155,566	156,850	134,239	144,273	133,496	121,762	137,355
Natural Gas (MMcf/d)										
Oil Sands	**33**	**30**	27	33	41	37	38	39	37	32
Conventional [2]	**561**	**536**	550	563	595	619	622	617	617	620
Total Natural Gas	**594**	**566**	577	596	636	656	660	656	654	652

(1) Natural gas liquids include condensate volumes.
(2) In Q1 2012, a non-core natural gas property was divested, decreasing 2012 production approximately 3%.

Average Royalty Rates

(excluding impact of realized gain (loss) on risk management)

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek	**11.8%**	**8.0%**	19.1%	4.6%	13.9%	16.8%	21.7%	20.6%	3.3%	21.2%
Christina Lake	**6.2%**	**5.7%**	5.3%	7.2%	7.0%	5.2%	4.7%	5.7%	6.3%	4.8%
Pelican Lake	**5.0%**	**4.5%**	6.6%	4.2%	4.5%	11.5%	9.1%	12.7%	9.7%	13.9%
Conventional										
Weyburn	**20.7%**	**17.9%**	19.8%	21.4%	23.3%	24.1%	24.8%	23.9%	23.6%	24.3%
Other	**7.2%**	**7.1%**	6.6%	6.8%	8.3%	8.3%	8.1%	9.0%	8.5%	7.6%
Natural Gas Liquids	**2.0%**	**2.3%**	2.5%	1.7%	1.7%	1.7%	1.8%	1.4%	2.3%	1.3%
Natural Gas	**1.2%**	**0.9%**	0.8%	0.4%	2.5%	1.7%	1.9%	1.5%	1.2%	2.3%

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Refining

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations (1)										
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**412**	**311**	442	451	445	401	424	413	406	362
Crude utilization	**91%**	**69%**	98%	100%	98%	89%	94%	91%	90%	80%
Refined products *(Mbbls/d)*	**433**	**330**	463	473	465	419	442	426	422	383

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

Selected Average Benchmark Prices

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
Brent Futures	**111.68**	**110.13**	109.42	108.76	118.45	110.91	109.02	112.09	116.99	105.52
West Texas Intermediate ("WTI")	**94.15**	**88.23**	92.20	93.35	103.03	95.11	94.06	89.54	102.34	94.60
Average Differential Brent Futures -WTI	**17.53**	**21.90**	17.22	15.41	15.42	15.80	14.96	22.55	14.65	10.92
Western Canadian Select ("WCS")	**73.12**	**70.12**	70.48	70.48	81.61	77.96	83.58	71.92	84.70	71.74
Differential - WTI-WCS	**21.03**	**18.11**	21.72	22.87	21.42	17.15	10.48	17.62	17.64	22.86
Condensate - (C5 @ Edmonton)	**100.88**	**98.14**	96.12	99.32	110.16	105.34	108.74	101.48	112.33	98.90
Differential - WTI-Condensate (premium)/discount	**(6.73)**	**(9.91)**	(3.92)	(5.97)	(7.13)	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)
Refining Margins 3-2-1 Crack Spreads (2) *(US$/bbl)*										
Chicago	**27.76**	**28.18**	35.64	28.20	19.00	24.55	19.23	33.35	29.00	16.62
Midwest Combined (Group 3)	**28.56**	**28.49**	35.99	28.28	21.50	25.26	20.75	34.04	27.19	19.04
Natural Gas Prices										
AECO *($/GJ)*	**2.28**	**2.90**	2.08	1.74	2.39	3.48	3.29	3.53	3.54	3.58
NYMEX *(US$/MMBtu)*	**2.79**	**3.40**	2.81	2.22	2.74	4.04	3.55	4.19	4.31	4.11
Differential - NYMEX/AECO *(US$/MMBtu)*	**0.38**	**0.31**	0.61	0.39	0.21	0.31	0.17	0.34	0.42	0.29

(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel, and reflect the current month WTI price as the crude oil feedstock price.

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)

	2012					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek ***($/bbl)*** (3)										
Price	**64.55**	**59.93**	63.95	63.83	70.71	67.38	75.96	62.68	72.23	59.50
Royalties	**7.36**	**4.55**	11.79	2.85	9.54	10.82	15.81	12.38	2.30	11.92
Transportation and blending	**2.41**	**2.91**	2.38	1.91	2.38	3.04	3.20	2.73	2.82	3.41
Operating	**11.99**	**11.26**	11.50	12.49	12.85	11.34	11.31	11.11	11.57	11.40
Netback	**42.79**	**41.21**	38.28	46.58	45.94	42.18	45.64	36.46	55.54	32.77
Heavy Oil - Christina Lake ***($/bbl)*** (3)										
Price	**47.73**	**43.37**	52.91	44.57	52.58	61.86	66.69	54.52	67.06	54.67
Royalties	**2.72**	**2.32**	2.61	2.90	3.37	3.03	2.97	2.87	3.98	2.44
Transportation and blending	**3.79**	**3.00**	4.00	4.12	4.51	3.53	2.98	4.54	3.51	3.69
Operating	**12.95**	**11.42**	13.59	12.52	15.33	20.20	17.96	23.01	23.41	19.09
Netback	**28.27**	**26.63**	32.71	25.03	29.37	35.10	42.78	24.10	36.16	29.45
Heavy Oil - Pelican Lake ***($/bbl)*** (3)										
Price	**69.23**	**64.37**	66.75	66.42	78.50	73.07	88.67	66.76	78.26	64.66
Royalties	**3.34**	**2.82**	4.34	2.68	3.37	7.91	6.98	8.23	7.40	8.63
Transportation and blending	**2.15**	**1.23**	1.09	3.54	2.88	4.14	12.19	1.87	2.02	2.44
Operating	**17.08**	**17.20**	17.47	17.71	16.05	14.86	16.49	14.31	13.40	15.35
Netback	**46.66**	**43.12**	43.85	42.49	56.20	46.16	53.01	42.35	55.44	38.24
Heavy Oil - Oil Sands ***($/bbl)*** (3)										
Price	**60.84**	**55.11**	61.71	59.00	68.36	67.99	76.39	62.93	73.02	60.35
Royalties	**5.22**	**3.47**	7.85	2.83	6.66	9.17	11.72	10.46	3.65	10.08
Transportation and blending	**2.74**	**2.63**	2.52	2.87	2.99	3.36	4.75	2.68	2.71	3.18
Operating	**13.33**	**12.41**	13.29	13.61	14.18	13.27	13.54	13.02	13.27	13.23
Netback	**39.55**	**36.60**	38.05	39.69	44.53	42.19	46.38	36.77	53.39	33.86
Heavy Oil - Conventional ***($/bbl)*** (3)										
Price	**70.53**	**64.73**	68.04	67.70	80.64	74.17	81.49	67.96	78.47	69.17
Royalties	**10.06**	**8.68**	8.81	9.36	13.06	10.75	11.85	11.33	10.98	9.04
Transportation and blending	**2.17**	**2.34**	2.31	2.26	1.81	1.27	1.34	1.80	0.91	1.05
Operating	**15.21**	**11.68**	16.48	15.07	17.57	13.77	16.34	12.40	13.66	12.78
Production and mineral taxes	**0.24**	**0.31**	0.27	0.25	0.14	0.32	0.34	0.17	0.22	0.51
Netback	**42.85**	**41.72**	40.17	40.76	48.06	48.06	51.62	42.26	52.70	45.79
Total Heavy Oil ***($/bbl)*** (3)										
Price	**62.05**	**56.22**	62.45	60.13	70.08	68.98	77.16	63.69	73.98	61.80
Royalties	**5.83**	**4.07**	7.96	3.68	7.56	9.42	11.74	10.59	4.93	9.91
Transportation and blending	**2.67**	**2.60**	2.50	2.79	2.82	3.02	4.23	2.55	2.40	2.83
Operating	**13.56**	**12.33**	13.66	13.80	14.65	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	**0.03**	**0.04**	0.03	0.03	0.02	0.05	0.05	0.03	0.04	0.08
Netback	**39.96**	**37.18**	38.30	39.83	45.03	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil ***($/bbl)***										
Price	**78.99**	**75.27**	76.06	76.16	88.45	85.40	90.90	79.57	94.30	77.39
Royalties	**8.09**	**6.92**	7.53	7.98	9.94	11.54	12.12	10.74	12.82	10.58
Transportation and blending	**2.65**	**2.39**	2.36	3.02	2.83	2.00	1.99	1.90	2.22	1.92
Operating	**15.51**	**15.63**	16.27	14.76	15.36	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	**2.44**	**2.51**	2.35	2.34	2.57	2.27	2.63	2.40	2.77	1.32
Netback	**50.30**	**47.82**	47.55	48.06	57.75	55.21	59.04	50.16	63.53	48.71

(3) The 2012 heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek - $41.85/bbl; Christina Lake - $45.83/bbl; Pelican Lake - $15.55/bbl; Heavy Oil - Oil Sands - $37.45/bbl; Heavy Oil - Conventional - $13.35/bbl and Total Heavy Oil - $34.44/bbl.

Operating Statistics - Before Royalties (continued)

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)	**2012**					2011				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil *($/bbl)*										
Price	**65.76**	**60.10**	65.37	63.91	74.22	72.80	80.49	67.37	78.71	65.32
Royalties	**6.32**	**4.65**	7.87	4.69	8.10	9.92	11.83	10.62	6.77	10.06
Transportation and blending	**2.66**	**2.55**	2.47	2.84	2.83	2.78	3.69	2.40	2.35	2.63
Operating	**13.99**	**13.00**	14.22	14.03	14.81	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	**0.56**	**0.54**	0.53	0.58	0.59	0.57	0.67	0.58	0.67	0.36
Netback	**42.23**	**39.36**	40.28	41.77	47.89	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids *($/bbl)*										
Price	**69.54**	**65.89**	61.53	65.52	83.36	76.84	82.26	74.38	80.32	70.67
Royalties	**1.42**	**1.52**	1.55	1.13	1.45	1.34	1.51	1.06	1.87	0.93
Netback	**68.12**	**64.37**	59.98	64.39	81.91	75.50	80.75	73.32	78.45	69.74
Total Liquids *($/bbl)*										
Price	**65.79**	**60.13**	65.35	63.92	74.28	72.84	80.50	67.43	78.72	65.37
Royalties	**6.29**	**4.64**	7.83	4.67	8.05	9.84	11.75	10.55	6.72	9.98
Transportation and blending	**2.65**	**2.54**	2.45	2.82	2.81	2.76	3.66	2.38	2.33	2.60
Operating	**13.90**	**12.93**	14.14	13.93	14.71	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	**0.56**	**0.54**	0.53	0.57	0.59	0.56	0.67	0.57	0.67	0.36
Netback	**42.39**	**39.48**	40.40	41.93	48.12	46.21	50.29	40.77	55.87	39.00
Total Natural Gas *($/Mcf)*										
Price	**2.42**	**2.97**	2.30	1.92	2.50	3.65	3.35	3.72	3.71	3.82
Royalties	**0.03**	**0.02**	0.02	0.01	0.06	0.06	0.06	0.05	0.04	0.08
Transportation and blending	**0.10**	**0.10**	0.08	0.08	0.13	0.15	0.14	0.15	0.14	0.17
Operating	**1.10**	**1.29**	1.08	0.98	1.08	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	**0.01**	**(0.01)**	0.02	0.02	0.02	0.04	0.01	0.03	0.05	0.06
Netback	**1.18**	**1.57**	1.10	0.83	1.21	2.30	1.92	2.50	2.50	2.32
Total *($/BOE)* [2]										
Price	**46.60**	**45.50**	46.61	43.25	50.84	49.75	53.48	46.97	51.81	46.83
Royalties	**4.00**	**3.08**	5.02	2.84	5.00	5.55	6.65	5.91	3.64	5.85
Transportation and blending	**1.88**	**1.86**	1.74	1.90	2.00	1.91	2.39	1.70	1.61	1.92
Operating [1]	**11.18**	**11.12**	11.35	10.75	11.46	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	**0.38**	**0.33**	0.38	0.40	0.40	0.41	0.40	0.39	0.49	0.36
Netback	**29.16**	**29.11**	28.12	27.36	31.98	31.53	32.95	29.09	36.38	28.02

(1) 2012 operating costs include costs related to long-term incentives of $0.16/BOE (2011 - $0.17/BOE).

Impact of realized gain (loss) on risk management

Liquids *($/bbl)*	**1.39**	**3.35**	2.02	1.64	(1.67)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas *($/Mcf)*	**1.14**	**0.89**	1.24	1.39	1.03	0.87	1.10	0.76	0.74	0.89
Total *($/BOE)* [2]	**3.42**	**4.05**	3.98	4.27	1.44	0.86	1.22	2.49	(1.25)	0.83

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.