



## **Management's discussion and analysis**

for the quarter ended September 30, 2012

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Throughout this document, the terms we, us, our and Cameco mean Cameco Corporation and its subsidiaries.

## Management's discussion and analysis

This management's discussion and analysis (MD&A) includes information that will help you understand management's perspective of our unaudited condensed consolidated interim financial statements and notes for the quarter ended September 30, 2012 (interim financial statements). The information is based on what we knew as of October 31, 2012 and updates our first and second quarter and annual MD&A included in our 2011 annual financial review.

As you review this MD&A, we encourage you to read our interim financial statements as well as our audited consolidated financial statements and notes for the year ended December 31, 2011 and annual MD&A. You can find more information about Cameco, including our audited consolidated financial statements and our most recent annual information form, on our website at [cameco.com](http://cameco.com), on SEDAR at [sedar.com](http://sedar.com) or on EDGAR at [sec.gov](http://sec.gov). You should also read our annual information form before making an investment decision about our securities.

The financial information in this MD&A and in our financial statements and notes are prepared according to International Financial Reporting Standards (IFRS), unless otherwise indicated.

Unless we have specified otherwise, all dollar amounts are in Canadian dollars.

### Caution about forward-looking information

Our MD&A includes statements and information about our expectations for the future. When we discuss our strategy, plans and future financial and operating performance, or other things that have not yet taken place, we are making statements considered to be *forward-looking information* or *forward-looking statements* under Canadian and United States securities laws. We refer to them in this MD&A as *forward-looking information*.

Key things to understand about the forward-looking information in this MD&A:

- It typically includes words and phrases about the future, such as: anticipate, estimate, expect, plan, will, intend, goal, target, forecast, strategy and outlook (see examples on page 2).
- It represents our current views, and can change significantly.
- It is based on a number of *material assumptions*, including those we have listed on page 3, which may prove to be incorrect.
- Actual results and events may be significantly different from what we currently expect, due to the risks associated with our business. We list a number of these *material risks* on pages 2 and 3. We recommend you also review our annual information form and our annual, first and second quarter MD&A, which include a discussion of other *material risks* that could cause actual results to differ significantly from our current expectations.
- Forward-looking information is designed to help you understand management's current views of our near and longer term prospects, and it may not be appropriate for other purposes. We will not necessarily update this information unless we are required to by securities laws.

### Examples of forward-looking information in this MD&A

- the discussion under the heading *Our strategy*
- our plan for increasing annual uranium supply to 36 million pounds by 2018, the expected sources for supply increases and expected production through 2016 at our uranium operations
- our expectation regarding production in our fuel services segment for 2012
- our expectation regarding the closing date for the NUKEM acquisition
- our expectations regarding the timing of the completion of our acquisition of the Yeelirrie uranium project
- our expectations about future global uranium supply, consumption, demand and number of new reactors, including the discussion under the heading *Uranium market update*
- our expectation that our average realized uranium price will improve in the fourth quarter of 2012
- the outlook for each of our operating segments for 2012, and our consolidated outlook for the year
- our expectation that we will continue to invest in expanding our production capacity over the next several years
- our expectation that our cash position will be substantially lower after we complete the NUKEM and Yeelirrie acquisitions
- our expectations regarding delivery patterns for our uranium and fuel service products
- our expectation that our operating and investment activities in 2012 will not be constrained by the financial covenants in our unsecured revolving credit facility
- our future plans for each of our uranium operating properties, development projects and projects under evaluation, and fuel services operating sites
- our expectations regarding timing for first commissioning in ore and first packaged pounds at Cigar Lake
- our McArthur River mineral reserve and resource estimates
- our forecasts of McArthur River production, operating and capital costs and mine life

### Material risks

- actual sales volumes or market prices for any of our products or services are lower than we expect for any reason, including changes in market prices or loss of market share to a competitor
- we are adversely affected by changes in foreign currency exchange rates, interest rates or tax rates
- our production costs are higher than planned, or necessary supplies are not available, or not available on commercially reasonable terms
- our estimates of production, purchases, costs, decommissioning or reclamation expenses, or our tax expense estimates, prove to be inaccurate
- we are unable to enforce our legal rights under our existing agreements, permits or licences, or are subject to litigation or arbitration that has an adverse outcome
- there are defects in, or challenges to, title to our properties
- our mineral reserve and resource estimates are not reliable, or we face unexpected or challenging geological, hydrological or mining conditions
- we are affected by environmental, safety and regulatory risks, including increased regulatory burdens or delays
- we cannot obtain or maintain necessary permits or approvals from government authorities
- we are affected by political risks in a developing country where we operate
- we are affected by terrorism, sabotage, blockades, civil unrest, accident or a deterioration in political support for, or demand for, nuclear energy
- we are impacted by changes in the regulation or public perception of the safety of nuclear power plants, which adversely affect the construction of new plants, the relicensing of existing plants and the demand for uranium
- there are changes to government regulations or policies that adversely affect us, including tax and trade laws and policies
- our uranium and conversion suppliers fail to fulfil delivery commitments
- our Cigar Lake and McArthur River development, mining or production plans are delayed or do not succeed, including infrastructure expansion at McArthur River
- we are affected by natural phenomena, including inclement weather, fire, flood and earthquakes
- our operations are disrupted due to problems with our own or our customers' facilities, the unavailability of reagents, equipment, operating parts and supplies critical to production, equipment failure, lack of tailings capacity, labour shortages, labour relations issues, strikes or lockouts, underground floods, cave ins, ground movements, tailings dam failures, transportation disruptions or accidents, or other development and operating risks
- with respect to the NUKEM and Yeelirrie acquisitions, the risk that closing conditions may not be satisfied in a timely manner, or at all

### Material assumptions

- our expectations regarding sales and purchase volumes and prices for uranium, fuel services and electricity
- our expectations regarding the demand for uranium, the construction of new nuclear power plants and the relicensing of existing nuclear power plants not being more adversely affected than expected by changes in regulation or in the public perception of the safety of nuclear power plants
- our expected production level and production costs
- our expectations regarding spot prices and realized prices for uranium, and other factors discussed on page 21, *Price sensitivity analysis: uranium*
- our expectations regarding uranium sales contract terminations, tax rates, foreign currency exchange rates and interest rates
- our decommissioning and reclamation expenses
- our mineral reserve and resource estimates, and the assumptions upon which they are based, are reliable
- the geological, hydrological and other conditions at our mines
- the success of our Cigar Lake and McArthur River development, mining and production plans, including infrastructure expansion at McArthur River
- our ability to continue to supply our products and services in the expected quantities and at the expected times
- our ability to comply with current and future environmental, safety and other regulatory requirements, and to obtain and maintain required regulatory approvals
- our operations are not significantly disrupted as a result of political instability, nationalization, terrorism, sabotage, blockades, civil unrest, breakdown, natural disasters, governmental or political actions, litigation or arbitration proceedings, the unavailability of reagents, equipment, operating parts and supplies critical to production, labour shortages, labour relations issues, strikes or lockouts, underground floods, cave ins, ground movements, tailings dam failure, lack of tailings capacity, transportation disruptions or accidents or other development or operating risks
- with respect to the NUKEM and Yeelirrie acquisitions, we have assumed that closing conditions will be satisfied within the expected timeframes

## Our strategy

We remain confident in the long-term fundamentals of the nuclear industry as world demand for safe, clean, reliable and affordable energy continues to grow. Nuclear energy remains an integral part of the energy mix, demonstrated by the 64 reactors under construction today.

However, recent developments in the nuclear industry, primarily centred around Japan, have caused more uncertainty in the rate of growth in nuclear power globally. This led us to review and adjust our outlook, and examine our long-term growth plans.

While market factors continue to evolve, our current view is that over the next decade (to 2021), we expect there will be 80 net new reactors, compared to the 95 previously anticipated. Most of this change is due to the retirement of some reactors and new reactor builds being pushed out beyond the 10-year period. As a result, we have revised our cumulative world uranium demand forecast to 2.1 billion pounds for that period, down 50 million pounds from our previous expectation. As always, we will continue to evaluate the effects on demand as the nuclear market evolves.

Given this expected near-term decrease in demand, we examined our portfolio of projects to determine if we should adjust the timing of development for them. From this review, we have decided to focus primarily on advancing our brownfield projects, while deferring development of our greenfield projects. However, we will undertake some measured activity to preserve the option to bring on these greenfield projects as quickly as possible should market conditions warrant doing so. In addition, we will advance our arrangement with Talvivaara and pace the expansion projects at Inkai. By taking these actions we expect to achieve about 36 million pounds of annual supply rather than 40 million pounds by 2018.

This means we plan to spread our capital spending over a longer period and decrease project-related expenses, which should enhance our nearer term financial picture. Subject to market conditions, we plan to undertake the following projects:

- bring Cigar Lake project to production
- expand production at the McArthur River mine
- refurbish and expand the Key Lake mill
- work to extend the Rabbit Lake mine life
- expand our US ISR production by advancing our various satellite operations
- advance the process for extracting uranium from the Talvivaara mine

Market opportunities will drive the rate of development of the following projects:

- advancing the Millennium project to achieve regulatory approvals as soon as possible to allow development to occur independently
- pacing the increase in uranium production at Inkai blocks 1 and 2 to match progress on the transfer of our refining/conversion technology, both subject to market conditions, and continuing work on the test leach facility at block 3
- completing the value engineering and the environmental permitting at Kintyre, but not proceeding with the detailed feasibility study

Of course, we will adjust the timing of our projects should market conditions evolve, which could change our supply plan. Adjusting a growth plan is not unique in our industry. A number of uranium producers have halted or delayed projects because they are not economic in today's environment. These economic challenges, driven by continued global economic turmoil and the issues surrounding nuclear power noted above, point to an uncertain future supply of global primary uranium production. And to fuel the 431 currently operating reactors, the 64 reactors under construction today, and the further growth we expect by 2021, new primary sources of production will be needed. We anticipate economics will eventually need to reflect the realities of bringing on new, higher cost production; it's a matter of timing.

As a result, we continue to prepare our assets now to ensure we can be among the first to respond when the market signals that new production is needed, and project economics improve. We want to be clear that any decision to increase our supply will be driven by profitability.

In the meantime, today's market environment calls for us to increase our focus on execution and maximize efficiencies in order to continually improve our margins to ensure we remain competitive. Specifically, we are in the process of reducing costs at all operations and corporate departments without compromising our values. In addition, we plan to decrease expenditures for exploration and research and development to better match market opportunities.

We maintain a strong balance sheet, which will be enhanced by taking these actions. As part of our normal strategic planning process, we will continue to review our capital structure and asset base to ensure it is optimal.

Our extraordinary assets, extensive portfolio of long-term sales contracts, employee expertise and comprehensive industry knowledge provide us with the confidence that we will be able to achieve these goals. And, as always, we will look for opportunities across the nuclear fuel cycle that we expect will complement and enhance our business.

We will continue to monitor the market closely and adjust our plans accordingly.

See the *uranium market update* on page 7 for more information on uranium supply and demand.

## Third quarter update

### Our performance

Highlights (\$ millions except where indicated)	Three months ended September 30			Nine months ended September 30			
	2012	2011	change	2012	2011	change	
Revenue	408	527	(23)%	1,363	1,414	(4)%	
Gross profit	135	179	(25)%	416	423	(2)%	
Net earnings	82	39	110%	221	186	19%	
\$ per common share (diluted)	0.21	0.10	110%	0.56	0.47	19%	
Adjusted net earnings (non-IFRS, see page 11)	52	104	(50)%	210	259	(19)%	
\$ per common share (adjusted and diluted)	0.13	0.26	(50)%	0.53	0.66	(20)%	
Cash provided by operations (after working capital changes)	44	192	(77)%	361	487	(26)%	
Average realized prices							
Uranium	\$US/lb	44.49	47.33	(6)%	45.76	47.06	(3)%
	\$Cdn/lb	44.99	45.97	(2)%	46.22	46.36	-
Fuel services	\$Cdn/kgU	16.98	17.42	(3)%	17.55	18.04	(3)%
Electricity	\$Cdn/MWh	54.00	54.00	-	55.00	54.00	2%

### Third quarter

Net earnings attributable to our shareholders (net earnings) this quarter were \$82 million (\$0.21 per share diluted) compared to \$39 million (\$0.10 per share diluted) in the third quarter of 2011. In addition to the items noted below, net earnings were impacted by higher mark-to-market gains on foreign exchange derivatives.

On an adjusted basis, our earnings this quarter were \$52 million (\$0.13 per share diluted) compared to \$104 million (\$0.26 per share diluted) (non-IFRS measure, see page 11) in the third quarter of 2011, mainly due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- higher expenditures for exploration and administration
- partially offset by higher earnings from our electricity business due to an increase in sales and lower costs

See *Financial results by segment* on page 19 for more detailed discussion.

## First nine months

Net earnings in the first nine months of the year were \$221 million (\$0.56 per share diluted) compared to \$186 million (\$0.47 per share diluted) in the first nine months of 2011. Net earnings were higher than in 2011 due to higher mark-to-market gains on foreign exchange derivatives and the items noted below.

On an adjusted basis, our earnings for the first nine months of this year were \$210 million (\$0.53 per share diluted) compared to \$259 million (\$0.66 per share diluted) (non-IFRS measure, see page 11). The change was due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- a \$30 million (US) contract termination charge
- higher expenditures for exploration and administration
- partially offset by higher earnings from our electricity business due to an increase in sales, higher realized prices and lower costs

See *Financial results by segment* on page 19 for more detailed discussion.

## Operations update

Highlights		Three months ended September 30			Nine months ended September 30		
		2012	2011	change	2012	2011	change
Uranium	Production volume (million lbs)	5.3	5.3	-	15.4	15.8	(3)%
	Sales volume (million lbs)	5.1	7.2	(29)%	18.1	19.1	(5)%
	Revenue (\$ millions)	231	332	(30)%	837	885	(5)%
	Gross profit (\$ millions)	83	133	(38)%	267	318	(16)%
Fuel services	Production volume (million kgU)	2.1	2.8	(25)%	10.9	11.6	(6)%
	Sales volume (million kgU)	3.3	4.6	(28)%	10.1	11.1	(9)%
	Revenue (\$ millions)	56	81	(31)%	178	199	(11)%
	Gross profit (\$ millions)	3	10	(70)%	23	29	(21)%
Electricity	Output (100%) (TWh)	7.1	6.7	6%	19.6	18.7	5%
	Revenue (100%) (\$ millions)	384	362	6%	1,095	1,016	8%
	Our share of earnings before taxes (\$ millions)	46	35	31%	125	75	67%

Production in our uranium segment this quarter was unchanged compared to the third quarter of 2011. For the first nine months, production was 3% lower than for the same period in 2011 mainly due to lower production at Smith Ranch-Highland. See *Uranium 2012 Q3 updates* starting on page 28 for more information.

### Key highlights:

- at McArthur River, mineral reserves increased by 19%. See pages 28 and 29 for more information
- at Inkai, we signed a memorandum of agreement with our joint venture partner, Kazatomprom, setting out a framework to increase uranium production and extend the duration of the mining licences at the Inkai operation, in conjunction with the joint development of a uranium refinery in Kazakhstan. See pages 31 and 32 for more information.
- in Saskatchewan, we received a funding commitment from the provincial government to construct a highway connecting McArthur River and Cigar Lake. See page 28 for more information.

Production in our fuel services segment was 25% lower this quarter than in the third quarter of 2011, and 6% lower for the first nine months compared to last year due to lower planned production in 2012. We continue to expect production to be between 13 million and 14 million kgU this year.

In our electricity segment, BPLP's generation was 6% higher for the quarter and 5% higher for the first nine months of the year compared to the same periods last year. The capacity factor this quarter was 99% and 92% for the first nine months.

**Also of note this quarter:**

On August 26, we announced an agreement with BHP Billiton to acquire the Yeelirrie uranium project in Western Australia for \$430 million (US). Yeelirrie is a near-surface calcrete-style deposit, amenable to open pit mining techniques.

We expect the transaction to close by the end of 2012, subject to the receipt of approvals from the government of Western Australia and the Australian Foreign Investment Review Board. Upon closing, stamp duty of about \$22 million (US) will also be payable to the government of Western Australia.

After closing, next steps will be for us to conduct a full document review of the project and develop plans for future necessary work.

## **Uranium market update**

Since the previous quarter, the nuclear industry continues to experience near- to medium-term uncertainty, driven primarily by the evolving situation in Japan.

In September 2012, a Japanese government panel announced a draft energy policy that included plans to phase out nuclear power generation by 2040. But the plan drew intense opposition from business groups and communities whose economies depend on the local nuclear power plants. The Japanese government did not adopt the plan, but agreed to take it under consideration while engaging with local governments, the public and the international community in developing an energy policy.

Japan's new Nuclear Regulatory Authority (NRA) also came into effect in September. It will create new regulatory standards against which reactor restarts will be evaluated. We believe the NRA brings important stability to the regulatory environment in Japan and has already brought some clarity to the issue of reactor restarts. It indicated that no additional reactors will be restarted until the new standards are in place – a process expected to take about 10 months. This requirement suggests there will be no more reactor restarts in Japan this year and possibly not until mid-2013 or later depending on when the standards are put in place.

The slower reactor restarts expected in Japan, combined with slower economic growth worldwide and changes to nuclear programs in some other countries led us to re-examine our reactor forecast. For example, Canada, France and Belgium have announced plans to retire their older reactors, and India has revised its 2020 nuclear target down from 20 to 14.6 gigawatts. So while the market continues to evolve, our initial review results in an estimated 80 net new reactors over the period 2012 to 2021, compared to the 95 we expected earlier this year. Most of the decrease is due to the retirement of reactors, although some is also due to deferrals beyond 2021.

## New Build Outlook – Planned Reactors (2012 to 2021)

Region / Country (as of Sept 30, 2012)	Operable	Previous Forecast			Change to net new	New Forecast	
		New	Shut	Net New		Net New	Operable 2021
Americas	127	11	(6)	5	(1)	4	131
Europe	137	11	(14)	(3)	(3)	(6)	131
Asia	77	14	(1)	13	(8)	5	82
Other*	6	7	-	7	-	7	13
India	20	15	-	15	(3)	12	32
China	15	52	-	52	-	52	67
Russia/E. Europe**	49	17	(11)	6	-	6	55
<b>Total</b>	<b>431</b>	<b>127</b>	<b>(32)</b>	<b>95</b>	<b>(15)</b>	<b>80</b>	<b>511</b>

\*Other includes Iran, Pakistan, South Africa, Turkey and United Arab Emirates.

\*\* Eastern Europe includes Armenia, Belarus and Ukraine.

Of these net new reactors, 64 are under construction today. China is the most aggressive, and we expect it to grow its nuclear power program from the 15 currently operating reactors to 67 in 2021, of which 26 are under construction.

The 80 net new reactors combined with the current base of nuclear power plants translates into a cumulative uranium demand of about 2.1 billion pounds to 2021, which is down by about 50 million pounds from our earlier forecast.

While expected demand has decreased, there has also been an increase in global supply. In China, Uzbekistan and Namibia production increased at a number of mines, which we expect will equate to about 30 million pounds of further supply over the 10-year period.

The result when we put these changes to supply and demand together is a demonstrated need for new supply of 360 million pounds from 2012 to 2021, compared to the 440 million pounds we had forecast earlier in the year.

However, the current market environment also poses challenges to bringing on new supply and could impact supply expectations as conditions continue to evolve. A number of project deferrals and cancellations have been announced as producers have reacted to lower uranium prices and general economic pressures. As well, secondary supplies continue to diminish, particularly with the end of the Russian Highly Enriched Uranium (HEU) agreement in 2013. Conclusion of this arrangement will mean the removal of 24 million pounds of relatively low-cost secondary annual uranium supply from the market, and there are no indications of a second Russian HEU deal.

Despite the changes we see to the supply/demand outlook, what remains clear is that new supply will be needed. Though some could come from additions to secondary supplies, the majority will need to come from new mines and expansions to existing mines at a time when pursuing such projects is becoming increasingly difficult. In addition, the long-term fundamentals of the industry remain strong, with 64 reactors currently under construction and some of the growth pushed further out in time. As a result, we are managing our assets through this period of uncertainty with a focus on safety, efficiency and profitable growth.

### Caution about forward-looking information relating to our uranium market update

This discussion of our expectations for the nuclear industry, including its growth profile and future global uranium supply and demand and the number of reactors, is forward-looking information that is based upon the assumptions and subject to the material risks discussed under the heading *Caution about forward-looking information* beginning on page 1.

## Industry prices

	Sep 30 2012	Jun 30 2012	Mar 31 2012	Sep 30 2011	Jun 30 2011	Mar 31 2011
<b>Uranium</b> (\$US/lb U <sub>3</sub> O <sub>8</sub> ) <sup>1</sup>						
Average spot market price	<b>46.50</b>	50.75	51.05	52.25	52.88	60.50
Average long-term price	<b>60.50</b>	61.25	60.00	63.50	68.00	70.00
<b>Fuel services</b> (\$US/kgU UF <sub>6</sub> ) <sup>1</sup>						
<b>Average spot market price</b>						
North America	<b>9.25</b>	6.63	6.63	9.50	11.00	12.00
Europe	<b>9.75</b>	7.00	7.00	9.50	11.00	12.00
<b>Average long-term price</b>						
North America	<b>16.75</b>	16.75	16.75	16.50	16.00	15.75
Europe	<b>17.25</b>	17.25	17.25	17.00	16.25	16.00
Note: the industry does not publish UO <sub>2</sub> prices.						
<b>Electricity</b> (\$/MWh)						
Average Ontario electricity spot price	<b>28.00</b>	19.00	20.00	33.00	28.00	32.00

<sup>1</sup> Average of prices reported by TradeTech and Ux Consulting (Ux)

On the spot market, where purchases call for delivery within one year, the volume reported for the third quarter of 2012 was just over 9 million pounds. This compares to about 13 million pounds in the third quarter of 2011.

Continued uncertainty in the market contributed to downward pressure on the spot price. At the end of the quarter, the average spot price was \$46.50 (US) per pound. On October 29, 2012, Ux reported a spot price of \$42.50 (US) per pound. In general, utilities are well covered under existing contracts, so we expect uranium demand in the near term to remain somewhat discretionary.

The long-term uranium price held relatively firm during the quarter. Long-term contracts usually call for deliveries to begin more than two years after the contract is finalized, and use a number of pricing formulas, including fixed prices adjusted by inflation indices, and market referenced prices (spot and long-term indicators quoted near the time of delivery).

Spot UF<sub>6</sub> conversion prices increased significantly during the quarter, in part due to a shutdown at one of the primary UF<sub>6</sub> conversion facilities. Long-term UF<sub>6</sub> conversion price indicators held firm throughout the quarter.

### Long-term fundamentals are strong

Electricity is essential to maintaining and improving the standard of living for people throughout the world, and nuclear power continues to be an affordable and sustainable source of safe, clean, reliable energy. New reactors are currently under construction around the world and the demand for uranium is expected to grow, and along with it, the need for new supply to meet future customer requirements.

Our long history of success comes from many years of hard work and discipline, developing and acquiring the expertise and assets we need to deliver on our strategy. We are well positioned to grow and be successful, and to build value for our shareholders.

#### Shares and stock options outstanding

At October 30, 2012, we had:

- 395,349,044 common shares and one Class B share outstanding
- 9,579,845 stock options outstanding, with exercise prices ranging from \$15.79 to \$54.38

#### Dividend policy

Our board of directors has established a policy of paying a quarterly dividend of \$0.10 (\$0.40 per year) per common share. This policy will be reviewed from time to time based on our cash flow, earnings, financial position, strategy and other relevant factors.

## Financial results

This section of our MD&A discusses our performance, financial condition and outlook for the future.

### 2012 Q3 results

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## Consolidated financial results

Highlights (\$ millions except per share amounts)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
Revenue	408	527	(23)%	1,363	1,414	(4)%
Gross profit	135	179	(25)%	416	423	(2)%
Net earnings	82	39	110%	221	186	19%
\$ per common share (basic)	0.21	0.10	110%	0.56	0.47	19%
\$ per common share (diluted)	0.21	0.10	110%	0.56	0.47	19%
Adjusted net earnings (non-IFRS, see page 11)	52	104	(50)%	210	259	(19)%
\$ per common share (adjusted and diluted)	0.13	0.26	(50)%	0.53	0.66	(20)%
Cash provided by operations (after working capital changes)	44	192	(77)%	361	487	(26)%

### Net earnings

Net earnings this quarter were \$82 million (\$0.21 per share diluted) compared to \$39 million (\$0.10 per share diluted) in the third quarter of 2011. In addition to the items noted below, net earnings were impacted by higher mark-to-market gains on foreign exchange derivatives.

On an adjusted basis, our earnings this quarter were \$52 million (\$0.13 per share diluted) compared to \$104 million (\$0.26 per share diluted) (non-IFRS measure, see page 11) in the third quarter of 2011, mainly due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- higher expenditures for exploration and administration
- partially offset by higher earnings from our electricity business

Net earnings in the first nine months of the year were \$221 million (\$0.56 per share diluted) compared to \$186 million (\$0.47 per share diluted) in the first nine months of 2011. Net earnings were higher than in 2011 due to higher mark-to-market gains on foreign exchange derivatives and the items noted below.

On an adjusted basis, our earnings for the first nine months of this year were \$210 million (\$0.53 per share diluted) compared to \$259 million (\$0.66 per share diluted) (non-IFRS measure, see page 11). The change was due to:

- lower earnings from our uranium business based on lower sales volumes, lower realized prices and higher costs
- a \$30 million (US) contract termination charge
- higher expenditures for exploration and administration
- partially offset by higher earnings from our electricity business due to an increase in sales, higher realized prices and lower costs

### Adjusted net earnings (non-IFRS measure)

Adjusted net earnings is a measure that does not have a standardized meaning or a consistent basis of calculation under IFRS (non-IFRS measure). We use this measure as a more meaningful way to compare our financial performance from period to period. We believe that, in addition to conventional measures prepared in accordance with IFRS, certain investors use this information to evaluate our performance. Adjusted net earnings is our net earnings attributable to equity holders, adjusted to better reflect the underlying financial performance for the reporting period. The adjusted earnings measure reflects the matching of the net benefits of our hedging program with the inflows of foreign currencies in the applicable reporting period.

Adjusted net earnings is non-standard supplemental information and should not be considered in isolation or as a substitute for financial information prepared according to accounting standards. Other companies may calculate this measure differently so you may not be able to make a direct comparison to similar measures presented by other companies.

The table below reconciles adjusted net earnings with our net earnings.

(\$ millions)	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
<b>Net earnings</b>	<b>82</b>	39	<b>221</b>	186
<b>Adjustments</b>				
Adjustments on derivatives <sup>1</sup> (pre-tax)	<b>(40)</b>	88	<b>(15)</b>	100
Income taxes on adjustments to derivatives	<b>10</b>	(23)	<b>4</b>	(27)
<b>Adjusted net earnings</b>	<b>52</b>	104	<b>210</b>	259

<sup>1</sup> In 2008, we opted to discontinue hedge accounting for our portfolio of foreign currency forward sales contracts. Since then, we have adjusted our gains or losses on derivatives to reflect what our earnings would have been had hedge accounting been applied.

The table that follows describes what contributed to the changes in adjusted net earnings this quarter.

Change in adjusted net earnings (\$ millions)		Three months ended September 30	Nine months ended September 30
<b>Adjusted net earnings – 2011</b>		<b>104</b>	<b>259</b>
<b>Change in gross profit by segment</b> (we calculate gross profit by deducting from revenue the cost of products and services sold, and depreciation and amortization (D&A), net of hedging benefits)			
Uranium	Lower sales volumes	(38)	(16)
	Lower realized prices (\$US)	(15)	(24)
	Foreign exchange impact on realized prices	10	21
	Higher costs	(6)	(32)
	Hedging benefits	1	(19)
	change - uranium	(48)	(70)
Fuel services	Lower sales volumes	(3)	(2)
	Lower realized prices (\$Cdn)	(1)	(5)
	(Higher) lower costs	(3)	1
	Hedging benefits	-	(2)
	change – fuel services	(7)	(8)
Electricity	Higher sales volumes	3	4
	Higher realized prices (\$Cdn)	-	9
	Lower costs	10	37
	change – electricity	13	50
<b>Other changes</b>			
	Higher exploration expenditures	(3)	(13)
	Higher administration expenditures	(1)	(18)
	Lower income taxes	9	44
	Contract termination charge	-	(30)
	Financing costs	(3)	(3)
	Other	(12)	(1)
<b>Adjusted net earnings – 2012</b>		<b>52</b>	<b>210</b>

See *Financial results by segment* on page 19 for more detailed discussion.

#### Average realized prices

		Three months ended September 30			Nine months ended September 30		
		2012	2011	change	2012	2011	change
Uranium	\$US/lb	44.49	47.33	(6)%	45.76	47.06	(3)%
	\$Cdn/lb	44.99	45.97	(2)%	46.22	46.36	-
Fuel services	\$Cdn/kgU	16.98	17.42	(3)%	17.55	18.04	(3)%
Electricity	\$Cdn/MWh	54.00	54.00	-	55.00	54.00	2%

## Quarterly trends

Highlights (\$ millions except per share amounts)	2012				2011				2010
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	
Revenue	408	391	564	970	527	426	461	673	
Net earnings	82	8	131	265	39	55	92	206	
\$ per common share (basic)	0.21	0.02	0.33	0.67	0.10	0.14	0.23	0.52	
\$ per common share (diluted)	0.21	0.02	0.33	0.67	0.10	0.14	0.23	0.52	
Adjusted net earnings (non-IFRS, see page 11)	52	34	124	249	104	71	84	190	
\$ per common share (adjusted and diluted)	0.13	0.09	0.31	0.63	0.26	0.18	0.22	0.48	
Cash provided by operations (after working capital changes)	44	(94)	411	258	192	23	271	111	

The table that follows presents the differences between net earnings and adjusted net earnings for the previous seven quarters.

(\$ millions)	2012				2011				2010
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	
Net earnings	82	8	131	265	39	55	92	206	
Adjustments									
Adjustments on derivatives <sup>1</sup> (pre-tax)	(40)	35	(10)	(22)	88	22	(10)	(22)	
Income taxes on adjustments to derivatives	10	(9)	3	6	(23)	(6)	2	6	
Adjusted net earnings (non-IFRS, see page 11)	52	34	124	249	104	71	84	190	

<sup>1</sup> In 2008, we opted to discontinue hedge accounting for our portfolio of foreign currency forward sales contracts. Since then, we have adjusted our gains or losses on derivatives to reflect what our earnings would have been had hedge accounting been applied.

Key things to note:

- our financial results are strongly influenced by the performance of our uranium segment, which accounted for 57% of consolidated revenues in the third quarter of 2012
- the timing of customer requirements, which tend to vary from quarter to quarter, drives revenue in the uranium and fuel services segments.
- net earnings do not trend directly with revenue due to unusual items and transactions that occur from time to time. We use adjusted net earnings, a non-IFRS measure, as a more meaningful way to compare our results from period to period.
- cash from operations tends to fluctuate as a result of the timing of deliveries and product purchases in our uranium and fuel services segments
- quarterly results are not necessarily a good indication of annual results due to the variability in customer requirements noted above

## Administration

(\$ millions)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
<b>Direct administration</b>	<b>37</b>	37	-	<b>110</b>	101	9%
<b>Stock-based compensation</b>	<b>2</b>	1	100%	<b>14</b>	5	180%
<b>Total administration</b>	<b>39</b>	38	3%	<b>124</b>	106	17%

Direct administration costs were unchanged this quarter and \$9 million higher for the first nine months compared to the same periods last year. The increase in the first nine months reflects the following:

- studies and analyses of various opportunities
- enhancements to information systems

Stock-based compensation expenses were \$14 million for the first nine months of 2012 compared to \$5 million for the same period in 2011. Our share price was nearly level in the first nine months of 2012, whereas it declined markedly in the first half of 2011.

## Exploration

Uranium exploration expenses were \$35 million this quarter compared to \$32 million in the same quarter in 2011, as exploration activity in Saskatchewan increased. Exploration expenses in the first nine months of the year increased to \$75 million from \$62 million in 2011. We expect exploration expenses to be about 15% to 20% higher than they were in 2011 due to an increase in evaluation activities at Kintyre and Inkai block 3. We are also continuing to focus efforts in Canada and the United States.

## Income taxes

In the third quarter of 2012, we recorded an income tax expense of \$3 million compared to a recovery of \$22 million in the third quarter of 2011. The expense this quarter was mainly due to higher pre-tax earnings related largely to the recording of \$53 million in gains on derivatives in 2012 compared to losses of \$76 million in 2011. The distribution of earnings between jurisdictions was also different compared to 2011. In 2012, we recorded losses of \$2 million in Canada compared to \$186 million in 2011, whereas earnings in foreign jurisdictions declined to \$86 million from \$203 million. The tax rate in Canada is higher than the average of the rates in the foreign jurisdictions in which we operate.

On an adjusted basis, we recorded an income tax recovery of \$7 million this quarter compared to an expense of \$2 million in the third quarter of 2011. Our effective tax rate this quarter on an adjusted net earnings basis reflects a recovery of 17% compared to an expense of 1% for the third quarter of 2011.

In the first nine months of 2012, we recorded an income tax recovery of \$33 million compared to a recovery of \$19 million in 2011. The increase in recovery for the first nine months of the year was mainly due to a change in the distribution of earnings. Also, we received additional certainty on particular tax provisions that allowed us to recognize a \$9 million recovery in our income tax expense.

On an adjusted basis, we recorded an income tax recovery of \$37 million in the first nine months of 2012 compared to an expense of \$8 million in 2011. Our effective tax rate for the first nine months of 2012, on an adjusted net earnings basis, reflects a recovery of 21% compared to an expense of 3% in 2011.

(\$ millions)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
<b>Pre-tax Adjusted Earnings<sup>1</sup></b>						
Canada <sup>2</sup>	(41)	(98)	58%	(182)	(160)	(14)%
Foreign	86	203	(58)%	354	427	(17)%
Total pre-tax adjusted earnings	45	105	(57)%	172	267	(36)%
<b>Adjusted Income Taxes<sup>1</sup></b>						
Canada <sup>2</sup>	(7)	(12)	42%	(46)	(27)	(70)%
Foreign	-	14	(100)%	9	35	(74)%
<b>Adjusted income tax expense (recovery)</b>	<b>(7)</b>	<b>2</b>	<b>(450)%</b>	<b>(37)</b>	<b>8</b>	<b>(563)%</b>
<b>Effective tax rate</b>	<b>(17)%</b>	<b>1%</b>	<b>(1800)%</b>	<b>(21)%</b>	<b>3%</b>	<b>(800)%</b>

<sup>1</sup> Pre-tax adjusted earnings and adjusted income taxes are non-IFRS measures.

<sup>2</sup> Our IFRS-based measures have been adjusted by the amounts reflected in the table in adjusted net earnings (non-IFRS measure on page 11).

### Foreign exchange

At September 30, 2012:

- The value of the US dollar relative to the Canadian dollar was \$1.00 (US) for \$0.98 (Cdn), down from \$1.00 (US) for \$1.02 (Cdn) at June 30, 2012. The exchange rate averaged \$1.00 (US) for \$1.00 (Cdn) over the quarter.
- We had foreign currency contracts of \$1.2 billion (US) and EUR 105 million at September 30, 2012. The US currency contracts had an average exchange rate of \$1.00 (US) for \$1.02 (Cdn).
- The mark-to-market gain on all foreign exchange contracts was \$44 million compared to an \$8 million loss at June 30, 2012. We received cash of \$3 million this quarter related to the settlement of foreign exchange contracts.

## Outlook for 2012

Our outlook for 2012 reflects the growth expenditures necessary to help us achieve our strategy. Our outlook for consolidated capital expenditures and consolidated tax rate has changed. We explain the changes below. All other items in the table are unchanged. We do not provide an outlook for the items in the table that are marked with a dash.

See *Financial results by segment* on page 19 for details.

### 2012 Financial outlook

	Consolidated	Uranium	Fuel services	Electricity
Production	-	21.7 million lbs	13 to 14 million kgU	-
Sales volume	-	31 to 33 million lbs	Decrease 10% to 15%	-
Capacity factor	-	-	-	93%
Revenue compared to 2011	Decrease 0% to 5%	Decrease 0% to 5% <sup>1</sup>	Decrease 10% to 15%	Increase 5% to 10%
Average unit cost of sales (including D&A)	-	Increase 0% to 5% <sup>2</sup>	Increase 10% to 15%	Decrease 15% to 20%
Direct administration costs compared to 2011 <sup>3</sup>	Increase 10% to 15%	-	-	-
Exploration costs compared to 2011	-	Increase 15% to 20%	-	-
Tax rate	<b>Recovery of 10% to 15%</b>	-	-	-
Capital expenditures	<b>\$730 million<sup>4</sup></b>	-	-	\$70 million

<sup>1</sup> Based on a uranium spot price of \$42.50 (US) per pound (the Ux spot price as of October 29, 2012), a long-term price indicator of \$60.00 (US) per pound (the Ux long-term indicator on September 30, 2012) and an exchange rate of \$1.00 (US) for \$1.00 (Cdn).

<sup>2</sup> This increase is based on the unit cost of sale for produced material and committed long-term purchases. If we decide to make discretionary purchases in 2012 then we expect the average unit cost of sales to increase further.

<sup>3</sup> Direct administration costs do not include stock-based compensation expenses. See page 14 for more information.

<sup>4</sup> Does not include our share of capital expenditures at BPLP.

Our customers choose when in the year to receive deliveries of uranium and fuel services products, so our quarterly delivery patterns, and therefore our sales volumes and revenue, can vary significantly. In the fourth quarter, we expect about 40% of our 2012 deliveries to occur with an improvement in our average realized uranium price due to pricing under the mix of contracts.

We now expect a recovery of 10% to 15% for our consolidated tax rate (previously a 5% to 10% recovery). The change is primarily related to the \$9 million recovery in our income tax expense that we recognized in the second quarter due to additional certainty we received on particular tax provisions.

We now expect our capital expenditures to be about \$730 million compared to our previous estimate of \$680 million due to changes in scope and scheduling of some of our projects in northern Saskatchewan.

### Sensitivity analysis

For the rest of 2012:

- a change of \$5 (US) per pound in both the Ux spot price (\$42.50 (US) per pound on October 29, 2012) and the Ux long-term price indicator (\$60.00 (US) per pound on September 30, 2012) would change revenue by \$13 million and net earnings by \$7 million

- a change of \$5/MWh in the electricity spot price would change our 2012 net earnings by \$1 million based on the assumption that the spot price will remain below the floor price of \$51.62/MWh provided under BPLP's agreement with the Ontario Power Authority (OPA)
- a one-cent change in the value of the Canadian dollar versus the US dollar would change revenue by \$2 million and adjusted net earnings by \$1 million. This sensitivity is based on an exchange rate of \$1.00 (US) for \$1.02 (Cdn).

## Liquidity and capital resources

Our financial objective is to make sure we have the cash and debt capacity to fund our operating activities, investments and growth. Over the past nine months we have announced three acquisitions:

- Millennium, which closed in June for \$150 million in cash
- NUKEM, expected to close by the end of the year (subject to regulatory approvals) and to use about \$250 million (US) of cash
- Yeelirrie, expected to close by the end of the year (subject to regulatory approvals) and to use about \$452 million (US) of cash, including the purchase price of \$430 million (US) and a stamp duty of about \$22 million (US) paid to the government of Western Australian upon close

Once complete, our current cash position is expected to be substantially lower. In addition, we expect to continue investing in expanding our production capacity over the next several years.

We have a number of alternatives to fund this continued growth including using our current cash balances, drawing on our existing credit facilities, entering new credit facilities, using our operating cash flow, and raising additional capital through debt or equity financings. We are always considering our financing options so that we can take advantage of favourable market conditions when they arise.

## Cash from operations

Cash from operations was \$148 million lower this quarter than in 2011 due largely to lower uranium deliveries. Working capital required \$72 million more in 2012 largely as a result of an increase in uranium inventories during the quarter. Not including working capital requirements, our operating cash flows this quarter were lower by \$77 million, based on lower profits in our uranium segment. See *Financial results by segment* on page 19 for details.

Cash from operations was \$126 million lower for the first nine months of 2012 than for the same period in 2011 mainly due to lower uranium profits and lower sales volumes, partially offset by higher profits from the electricity business. Not including working capital requirements, our operating cash flows in the first nine months were down by \$120 million.

## Debt

We use debt to provide additional liquidity. We have sufficient borrowing capacity with unsecured lines of credit totalling about \$1.9 billion at September 30, 2012, the same as at June 30, 2012. At September 30, 2012, we had approximately \$669 million outstanding in letters of credit.

## Debt covenants

We are bound by certain covenants in our unsecured revolving credit facility. The financially related covenants place restrictions on total debt, including guarantees. As at September 30, 2012, we met these financial covenants and do not expect our operating and investment activities for the remainder of 2012 to be constrained by them.

## Long-term contractual obligations and off-balance sheet arrangements

We had two kinds of off-balance sheet arrangements at September 30, 2012:

- purchase commitments
- financial assurances

Other than the NUKEM and the Yeelirrie agreements noted on page 17, as well as the purchase of an incremental interest in the Millennium project for \$150 million which closed in June 2012, there have been no material changes to our long-term contractual obligations, purchase commitments and financial assurances since December 31, 2011, including payments due for the next five years and thereafter. Our long-term contractual obligations do not include our sales commitments. Please see our annual MD&A for more information.

### Balance sheet

(\$ millions)	Sep 30, 2012	Dec 31, 2011	change
Cash and short-term investments	664	1,202	(45)%
Total debt	993	1,039	(4)%
Inventory	719	494	46%

Total cash and short-term investments at September 30, 2012 were \$664 million, or 45% lower than at December 31, 2011 due to a higher rate of capital expenditures and our purchase of an incremental interest in the Millennium project. Net debt at September 30, 2012 was \$329 million.

Total debt decreased by \$46 million to \$993 million at September 30, 2012. Of this total, \$79 million was classified as current, down \$34 million compared to December 31, 2011. See notes 16 and 17 of our audited annual financial statements for more detail.

Total product inventories increased to \$719 million. Uranium inventories increased, as sales were lower than production and purchases in the first nine months of the year. Fuel services inventories increased as sales were also lower than production and purchases.

## Financial results by segment

### Uranium

Highlights	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
Production volume (million lbs)	5.3	5.3	-	15.4	15.8	(3)%
Sales volume (million lbs)	5.1	7.2	(29)%	18.1	19.1	(5)%
Average spot price (\$US/lb)	48.08	51.04	(6)%	50.38	57.89	(13)%
Average long-term price (\$US/lb)	60.67	65.33	(7)%	60.67	68.22	(11)%
Average realized price (\$US/lb)	44.49	47.33	(6)%	45.76	47.06	(3)%
(\$Cdn/lb)	44.99	45.97	(2)%	46.22	46.36	-
Average unit cost of sales (\$Cdn/lb U <sub>3</sub> O <sub>8</sub> ) (including D&A)	28.75	27.59	4%	31.47	29.68	6%
Revenue (\$ millions)	231	332	(30)%	837	885	(5)%
Gross profit (\$ millions)	83	133	(38)%	267	318	(16)%
Gross profit (%)	36	40	(10)%	32	36	(11)%

#### Third quarter

Production volumes this quarter were unchanged compared to the third quarter of 2011. See *Uranium 2012 Q3 updates* starting on page 28 for more information.

Uranium revenues this quarter were down 30% compared to 2011, due to a 29% decrease in sales volumes and a 2% decrease in the \$Cdn realized selling price.

Our realized prices this quarter were lower than the third quarter of 2011 mainly due to lower \$US prices under fixed-price contracts. In the third quarter of 2012, our realized foreign exchange rate was \$1.01, compared to \$0.97 for the prior year.

Total cost of sales (including D&A) decreased by 26% (\$147 million compared to \$199 million in 2011). This was mainly the result of the following:

- a 29% decrease in sales volumes
- lower royalty charges (\$7 million in 2012; \$26 million in 2011) due to decreased deliveries of Saskatchewan-produced material
- partially offset by average unit costs for produced uranium being 16% higher due to increased non-cash production costs at our ISR locations

The net effect was a \$50 million decrease in gross profit for the quarter.

#### First nine months

Production volumes for the first nine months of the year were lower than in the previous year due to lower output at Smith Ranch-Highland and Inkai. See *Uranium 2012 Q3 updates* on page 28 for more information.

For the first nine months of 2012, uranium revenues were down 5% compared to 2011, due to a 5% decrease in sales volumes.

Our \$US realized prices were lower than the first nine months of 2011 mainly due to lower prices under market-related contracts being offset by a more favourable exchange rate. In the first nine months of 2012, our realized foreign exchange rate was \$1.01 compared to \$0.99 in the prior year.

Total cost of sales (including D&A) increased by 1% (\$570 million compared to \$567 million in 2011). This was mainly the result of the following:

- average unit costs for produced uranium were 13% higher due to increased unit production costs relating mainly to the lower production during the first nine months. We continue to expect our average unit cost of sales (including D&A) to increase by 0% to 5% for the year compared to 2011.
- royalty charges in 2012 were \$2 million higher due to increased deliveries of Saskatchewan-produced material
- partially offset by a 5% decrease in sales volume

The net effect was a \$51 million decrease in gross profit for the first nine months.

The following table shows the costs of produced and purchased uranium incurred in the reporting periods (non-IFRS measures see below). These costs do not include selling costs such as royalties, transportation and commissions, nor do they reflect the impact of opening inventories on our reported cost of sales.

(\$Cdn/lb)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
<b>Produced</b>						
Cash cost	21.11	17.89	18%	21.18	18.87	12%
Non-cash cost	8.62	7.79	11%	8.01	6.92	16%
Total production cost	29.73	25.68	16%	29.19	25.79	13%
Quantity produced (million lbs)	5.3	5.3	-	15.4	15.8	(3)%
<b>Purchased</b>						
Cash cost	26.08	17.90	46%	27.04	28.32	(5)%
Quantity purchased (million lbs)	4.6	3.1	48%	8.4	7.3	15%
<b>Totals</b>						
Produced and purchased costs	28.03	22.81	23%	28.43	25.36	12%
Quantities produced and purchased (million lbs)	9.9	8.4	18%	23.8	23.1	3%

Cash cost per pound, non-cash cost per pound and total cost per pound for produced and purchased uranium presented in the above table are non-IFRS measures. These measures do not have a standardized meaning or a consistent basis of calculation under IFRS. We use these measures in our assessment of the performance of our uranium business. We believe that, in addition to conventional measures prepared in accordance with IFRS, certain investors use this information to evaluate our performance and ability to generate cash flow.

These measures are non-standard supplemental information and should not be considered in isolation or as a substitute for measures of performance prepared according to accounting standards. These measures are not necessarily indicative of operating profit or cash flow from operations as determined under IFRS. Other companies may calculate these measures differently so you may not be able to make a direct comparison to similar measures presented by other companies.

To facilitate a better understanding of these measures, the following table presents a reconciliation of these measures to our unit cost of sales for the third quarters and first nine months of 2012 and 2011.

## Cash and total cost per pound reconciliation

(\$ millions)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
<b>Cost of product sold</b>	<b>121.8</b>	164.7	(26)%	<b>480.6</b>	487.5	(1)%
<b>Add / (subtract)</b>						
Royalties	<b>(6.7)</b>	(26.3)	(75)%	<b>(64.3)</b>	(62.3)	3%
Standby charges	<b>(8.0)</b>	(5.2)	54%	<b>(20.9)</b>	(16.0)	31%
Other selling costs	<b>(0.6)</b>	(0.6)	-	<b>(2.9)</b>	(6.7)	(57)%
Change in inventories	<b>125.4</b>	17.7	608%	<b>160.9</b>	102.5	57%
<b>Cash operating costs (a)</b>	<b>231.9</b>	150.3	54%	<b>553.4</b>	505.0	10%
<b>Add / (subtract)</b>						
Depreciation and amortization	<b>25.7</b>	34.3	(25)%	<b>89.5</b>	79.1	13%
Change in inventories	<b>19.9</b>	7.0	184%	<b>33.7</b>	1.7	1882%
<b>Total operating costs (b)</b>	<b>277.5</b>	191.6	45%	<b>676.6</b>	585.8	16%
Uranium produced & purchased (millions lbs) (c)	<b>9.9</b>	8.4	18%	<b>23.8</b>	23.1	3%
<b>Cash costs per pound (a ÷ c)</b>	<b>23.42</b>	17.89	31%	<b>23.25</b>	21.86	6%
<b>Total costs per pound (b ÷ c)</b>	<b>28.03</b>	22.81	23%	<b>28.43</b>	25.36	12%

## Price sensitivity analysis: uranium

The table below is *not* a forecast of prices we expect to receive. The prices we actually realize will be different from the prices shown in the table.

It is designed to indicate how our portfolio of long-term contracts would respond to different spot prices. In other words, we would realize these prices only if the contract portfolio remained the same and none of the assumptions we list below change.

We intend to update this table each quarter in our MD&A to reflect deliveries made and changes to our contract portfolio each quarter. As a result we expect the table to change from quarter to quarter.

*Expected realized uranium price sensitivity under various spot price assumptions*  
(rounded to the nearest \$1.00)

(\$US/lb U <sub>3</sub> O <sub>8</sub> )							
Spot prices	\$20	\$40	\$60	\$80	\$100	\$120	\$140
2012	46	46	49	50	52	53	55
2013	42	46	54	63	72	81	89
2014	45	48	56	64	73	82	89
2015	41	46	56	66	76	87	96
2016	44	49	58	68	78	88	97

The table illustrates the mix of long-term contracts in our portfolio, and is consistent with our contracting strategy. The changes to the table in the quarter are mainly due to:

- deliveries made and contracts entered into
- changes to deliveries under some contracts where deliveries are tied to reactor requirements

Our portfolio includes a mix of fixed-price and market-related contracts, which we target at a 40:60 ratio. We signed many of our current contracts in 2003 to 2005, when market prices were low (\$11 to \$31 (US)). Those that are fixed at lower prices or have low ceiling prices will yield prices that are lower than current market prices. These older contracts are beginning to expire, and we are starting to deliver into more favourably priced contracts.

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Our portfolio is affected by more than just the spot price. We made the following assumptions (which are not forecasts) to create the table:

*Sales*

- sales volumes on average of 32 million pounds per year

*Deliveries*

- customers take the maximum quantity allowed under each contract (unless they have already provided a delivery notice indicating they will take less)
- we defer a portion of deliveries under existing contracts for 2012

*Prices*

- the average long-term price indicator is the same as the average spot price for the entire year (a simplified approach for this purpose only). Since 1996, the long-term price indicator has averaged 14% higher than the spot price. This differential has varied significantly. Assuming the long-term price is at a premium to spot, the prices in the table will be higher.
- we deliver all volumes that we don't have contracts for at the spot price for each scenario

*Inflation*

- is 2% per year

## Fuel services

(includes results for UF<sub>6</sub>, UO<sub>2</sub> and fuel fabrication)

Highlights	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
Production volume (million kgU)	2.1	2.8	(25)%	10.9	11.6	(6)%
Sales volume (million kgU)	3.3	4.6	(28)%	10.1	11.1	(9)%
Realized price (\$Cdn/kgU)	16.98	17.42	(3)%	17.55	18.04	(3)%
Average unit cost of sales (\$Cdn/kgU) (including D&A)	16.20	15.34	6%	15.32	15.42	(1)%
Revenue (\$ millions)	56	81	(31)%	178	199	(11)%
Gross profit (\$ millions)	3	10	(70)%	23	29	(21)%
Gross profit (%)	5	12	(58)%	13	15	(13)%

### Third quarter

Production volumes in the quarter were 25% lower than in 2011 due to the reduction of planned production for 2012.

Total revenue was \$25 million lower than in 2011 due to a 28% decline in deliveries of our fuel services products and a 3% decline in the realized selling price.

Our \$Cdn realized price for fuel services was affected by the mix of products delivered in the quarter. In 2012, a higher proportion of fuel services sales were for UF<sub>6</sub>, which typically yields a lower price than the other fuel services products.

The total cost of sales (including D&A) decreased by 25% (\$53 million compared to \$71 million in 2011) due to the decrease in the sales volumes. The average unit cost of sales was 6% higher due to the mix of products delivered in the quarter.

The net effect was a decrease of \$7 million in gross profit for the quarter.

### First nine months

Production was 10.9 million kgU, 6% lower than the same period last year. As a result of the planned reduction in production, results will remain lower than comparable periods in 2011; production remains on track for the year.

Total revenue decreased by 11% due to a 9% decrease in sales volumes and a 3% decline in the realized selling price.

The total cost of sales (including D&A) decreased by 9% (\$155 million compared to \$170 million in 2011) due to the decrease in the sales volume. The average unit cost of sales was similar to the first nine months of 2011.

The net effect was a \$6 million decrease in gross profit.

## Electricity

### BPLP

(100% – not prorated to reflect our 31.6% interest)

Highlights (\$ millions except where indicated)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
Output - terawatt hours (TWh)	7.1	6.7	6%	19.6	18.7	5%
Capacity factor (the amount of electricity the plants actually produced for sale as a percentage of the amount they were capable of producing)	99%	93%	6%	92%	87%	6%
Realized price (\$/MWh)	54	54	-	55 <sup>1</sup>	54 <sup>2</sup>	2%
Average Ontario electricity spot price (\$/MWh)	28	33	(15)%	22	31	(29)%
Revenue	384	362	6%	1,095	1,016	8%
Operating costs (net of cost recoveries)	223	232	(4)%	668	735	(9)%
Cash costs	167	182	(8)%	504	592	(15)%
Non-cash costs	56	50	12%	164	143	15%
Income before interest and finance charges	161	130	24%	427	281	52%
Interest and finance charges	10	14	(29)%	20	30	(33)%
Cash from operations	91	137	(34)%	442	376	18%
Capital expenditures	52	61	(15)%	140	158	(11)%
Distributions	95	80	19%	285	205	39%
Capital calls	17	-	-	50	11	355%
Operating costs (\$/MWh)	31	35	(11)%	33 <sup>1</sup>	39 <sup>2</sup>	(15)%

<sup>1</sup> Nine months ended September 30, 2012 are based on actual generation of 19.6 TWh plus deemed generation of 0.4 TWh

<sup>2</sup> Nine months ended September 30, 2011 are based on actual generation of 18.7 TWh plus deemed generation of 0.2 TWh

### Our earnings from BPLP

Highlights (\$ millions except where indicated)	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
BPLP's earnings before taxes (100%)	151	116	30%	407	251	62%
Cameco's share of pretax earnings before adjustments (31.6%)	48	37	30%	129	79	63%
Proprietary adjustments	(2)	(2)	-	(4)	(4)	-
Earnings before taxes from BPLP	46	35	31%	125	75	67%

### Third quarter

Total electricity revenue increased by 6% this quarter compared to the third quarter of 2011 due to higher output. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$166 million this quarter under its agreement with the OPA, compared to \$119 million in the third quarter of 2011. About 72% of BPLP's output was sold under financial contracts this quarter

compared to 53% in the third quarter of 2011. From time to time BPLP enters the market to lock in the gains under these contracts. Gains on BPLP's contracting activity were slightly lower than in 2011.

The capacity factor was 99% this quarter, up from 93% in the third quarter of 2011 as a result of no planned outage days. Operating costs were slightly lower at \$223 million compared to \$232 million in 2011.

The result was a \$11 million increase in our share of earnings before taxes.

BPLP distributed \$95 million to the partners in the third quarter; our share was \$30 million. Also, BPLP made capital calls of \$17 million to the partners in the third quarter; our share was \$5 million. The partners have agreed that BPLP will distribute excess cash monthly and will make separate cash calls for major capital projects.

### **First nine months**

Total electricity revenue for the first nine months increased 8% compared to 2011 due to higher output and higher realized prices. Realized prices reflect spot sales, revenue recognized under BPLP's agreement with the OPA and financial contract revenue. BPLP recognized revenue of \$575 million in the first nine months of 2012 under its agreement with the OPA, compared to \$351 million in the first nine months of 2011. The equivalent of about 67% of BPLP's output was sold under financial contracts in the first nine months of this year, compared to 49% in 2011. From time to time BPLP enters the market to lock in the gains under these contracts. Gains on BPLP's contracting activity were slightly higher than in 2011.

The capacity factor was 92% for the first nine months of this year, up from 87% in the third quarter of 2011 due to a lower volume of outage days during this year's planned outage compared to last year's planned outage. Operating costs were lower at \$668 million compared to \$735 million in 2011 mainly due to lower supplemental lease payments and lower maintenance costs. These decreases were partially offset by higher fuel costs in the first nine months of 2012.

The result was a \$50 million increase in our share of earnings before taxes.

BPLP distributed \$285 million to the partners in the first nine months of 2012; our share was \$90 million. BPLP made capital calls of \$50 million to the partners in the first nine months of this year; our share was \$16 million.

## Our operations and development projects

### Uranium – production overview

Production in our uranium segment this quarter was unchanged compared to the third quarter of 2011. For the first nine months, production was down compared to the same period last year mainly due to lower production at Smith Ranch-Highland. See *Uranium 2012 Q3 updates* starting on page 28 for more information.

#### Uranium production

Cameco's share (million lbs U <sub>3</sub> O <sub>8</sub> )	Three months ended September 30			Nine months ended September 30		
	2012	2011	change	2012	2011	change
McArthur River/Key Lake	3.8	3.8	-	10.1	10.0	1%
Rabbit Lake	0.3	0.5	(40)%	2.1	2.2	(5)%
Smith Ranch-Highland	0.3	0.3	-	0.8	1.2	(33)%
Crow Butte	0.2	0.2	-	0.6	0.6	-
Inkai	0.7	0.5	40%	1.8	1.8	-
<b>Total</b>	<b>5.3</b>	<b>5.3</b>	<b>-</b>	<b>15.4</b>	<b>15.8</b>	<b>(3)%</b>

#### Outlook

We have geographically diverse sources of production. Subject to market conditions, our plan is to focus primarily on advancing our brownfield projects and the process to extract uranium from the Talvivaara mine to achieve annual supply of 36 million pounds by 2018.

#### *Cameco's share of production — annual forecast to 2016*

Current forecast (million lbs)	2012	2013	2014	2015	2016
McArthur River/Key Lake	13.5	13.2	13.1	13.1	13.1
Rabbit Lake	3.7	3.7	3.7	3.7	3.4
US ISR	2.0	3.0	3.1	3.7	3.8
Inkai <sup>1</sup>	2.5	2.9	2.9	2.9	2.9
Cigar Lake	-	0.3	1.9	5.5	7.9
<b>Total share of production</b>	<b>21.7</b>	<b>23.1</b>	<b>24.7</b>	<b>28.9<sup>3</sup></b>	<b>31.1</b>
<b>Cameco's share of Inkai's production on which profits are generated<sup>1</sup></b>					
Inkai <sup>1</sup>	2.6	3.0	3.0	3.0	3.0
<b>Total<sup>2</sup></b>	<b>21.8</b>	<b>23.2</b>	<b>24.8</b>	<b>29.0<sup>4</sup></b>	<b>31.2</b>

<sup>1</sup> In 2011, we signed a memorandum of agreement (2011 MOA) with Kazatomprom to increase annual production to 5.2 million pounds (100% basis). Once implemented, we will receive the right to purchase 2.9 million pounds of Inkai's annual production and receive profits on 3.0 million pounds.

<sup>2</sup> We have adjusted the production table to reflect the share of Inkai's production we will use to calculate our profits under the 2011 MOA, as described in the note above.

<sup>3</sup> Corrected on November 6, 2012 from 29.1 million pounds.

<sup>4</sup> Corrected on November 6, 2012 from 29.2 million pounds.

Our 2012 and future annual production targets for Inkai assume, and we expect:

- Inkai will obtain the necessary government permits and approvals to produce at an annual rate of 5.2 million pounds (100% basis), including an amendment to the resource use contract
- we implement the 2011 MOA
- Inkai will ramp up production to an annual rate of 5.2 million pounds (100% basis)

There is no certainty Inkai will receive these permits or approvals or we will implement the 2011 MOA or that Inkai will be able to ramp up production. If Inkai does not, or if the permits and approvals are delayed, Inkai may be unable to achieve its 2012 and future annual production targets and we may have to re-categorize some of Inkai's mineral reserves as resources.

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This forecast is forward-looking information. It is based on the assumptions and subject to the material risks discussed on pages 2 and 3, and specifically on the assumptions and risks listed here. Actual production may be significantly different from this forecast.

*Assumptions*

- we achieve our forecast production for each operation, which requires, among other things, that our mining plans succeed, processing plants and equipment are available and function as designed, we have sufficient tailings capacity and our mineral reserve estimates are reliable
- we obtain or maintain the necessary permits and approvals from government authorities
- our production is not disrupted or reduced as a result of natural phenomena, labour disputes, political risks, blockades or other acts of social or political activism, shortage or lack of supplies critical to production, equipment failures or other development and operation risks

*Material risks that could cause actual results to differ materially*

- we do not achieve forecast production levels for each operation because of a change in our mining plans, processing plants or equipment are not available or do not function as designed, lack of tailings capacity or for other reasons
- we cannot obtain or maintain necessary permits or approvals from government authorities
- natural phenomena, labour disputes, political risks, blockades or other acts of social or political activism, shortage or lack of supplies critical to production, equipment failures or other development and operation risks disrupt or reduce our production

## Uranium 2012 Q3 updates

### Operating properties

#### McArthur River/Key Lake

##### Production update

Production for the quarter and the first nine months was unchanged compared to the same periods last year. We expect our share of production this year to increase to 13.5 million pounds compared to our previous forecast of 13.1 million pounds U<sub>3</sub>O<sub>8</sub>.

Production varies from quarter to quarter depending on the sequencing of mining raises and timing of maintenance shutdowns at the mill.

##### Operations update

At McArthur River, we have started to upgrade our electrical infrastructure to address the future need for increased ventilation and freeze capacity associated with mining new zones and increasing mine production.

At Key Lake, the new steam, oxygen and acid plants are operational. We have started projects to replace the calciner and the electrical substation.

We continue to make excellent progress in flattening the slope of the Deilmann tailings management facility pitwalls at Key Lake. The project will reduce the risk of loss of tailings capacity due to pitwall sloughing.

We are continuing to advance work on the environmental assessment for the Key Lake extension project. We have received comments from the regulators on our draft environmental impact statement and are working to address the questions and issues they have raised. We plan to submit the final environmental impact statement in 2013.

In cooperation with several uranium industry partners in Saskatchewan, we have been working on a plan with the provincial government to connect our McArthur River and Cigar Lake mine sites by completing Highway 914 in the Athabasca Basin. This crucial connection will expand access to milling infrastructure across the northern part of the province, enhance transportation efficiency and offer an alternate route in and out of northern Saskatchewan. The Government of Saskatchewan has agreed to fund half of the cost of the final road with the industry partners sharing the remaining half.

##### Technical report

We are updating the February 2009 McArthur River technical report to reflect further advancements and changes to the McArthur River operations since that time. We plan to file the updated technical report during the fourth quarter. The highlights of the technical report are:

- a 19% increase in our share of the mineral reserves estimate from 226.2 million pounds at December 31, 2011 to 269.1 million pounds as of August 31, 2012 due to a 22% addition in tonnage and a slight decrease in the estimated average grade. See *McArthur River mineral reserves and mineral resources estimates* table below for more details.
- a decrease in the estimated average cash operating cost to about \$19.23 per pound over the life of the mine from about \$19.69 per pound estimated in 2009, despite the escalating costs in the industry. See table titled *McArthur River/Key Lake life of mine production, average unit operating costs and capital cost forecasts* below for more details.
- a production rate increase to 22 million pounds per year scheduled for 2018, subject to regulatory approval
- a mine life of at least 22 years, based on the planned production schedule
- our share of capital costs at McArthur River and Key Lake to 2034 is estimated at \$2.5 billion compared to \$1.4 billion in the previous report. More than 40% of this increase is related to the addition of more than 85 million pounds of new production since the 2009 technical report, and about 15% relates to expenditures required to allow production at a higher rate such as additional ventilation including the sinking of a fourth shaft. The

remainder of the increase is related to expanding the infrastructure to support ongoing and expanded operations, and general cost escalation. We expect these changes will generate significant cash flows for years to come.

### McArthur River mineral reserves and mineral resources estimates

(tonnes in thousands, pounds in millions)

(as at August 31, 2012)	Tonnes	Grade % U <sub>3</sub> O <sub>8</sub>	Content (lbs U <sub>3</sub> O <sub>8</sub> )	Cameco's share of content (lbs U <sub>3</sub> O <sub>8</sub> )
<b>Reserves</b>				
Proven	384.4	23.81	201.8	140.8
Probable	677.8	12.30	183.7	128.3
<b>Total proven and probable mineral reserves</b>	<b>1,062.2</b>	<b>16.46</b>	<b>385.5</b>	<b>269.1</b>
<b>Resources</b>				
Measured	68.6	5.53	8.4	5.8
Indicated	15.5	9.97	3.4	2.4
<b>Total measured and indicated mineral resources</b>	<b>84.1</b>	<b>6.35</b>	<b>11.8</b>	<b>8.2</b>
<b>Inferred mineral resources</b>	<b>325.0</b>	<b>7.86</b>	<b>56.3</b>	<b>39.3</b>

#### Notes:

- Mineral reserves and mineral resources are reported separately. Mineral resources do not include amounts identified as mineral reserves. Reported mineral reserves have not been adjusted for estimated mill recovery of 98.7%.
- Our share of total mineral reserves and total mineral resources is 69.805%.
- Inferred mineral resources have a great amount of uncertainty as to their existence and whether they can be mined legally or economically. It cannot be assumed that all or any part of the inferred mineral resources will be upgraded to a higher category.
- Mineral resources are estimated at a minimum mineralized thickness of 1.0 metre and a minimum grade of 0.1% to 0.5% U<sub>3</sub>O<sub>8</sub> assuming extraction by underground mining methods. Mineral reserves have been estimated at a cut-off grade of 0.77% U<sub>3</sub>O<sub>8</sub>.
- The geological model employed for McArthur River involves geological interpretations on section and plan derived from surface and underground drillhole information.
- Mineral reserves include allowances for estimated dilution (20%) from backfill and mineralized waste mined and mining recovery (97.5%). Mineral resources do not include such allowances.
- Mineral reserves are estimated using the raisebore, boxhole and blasthole stope mining methods combined with freeze curtains.
- Mineral resources are estimated using a cross-sectional method and 3-dimensional block models. Mineral reserves are estimated using 3-dimensional block models.
- An average uranium price assumption of \$61US/lb U<sub>3</sub>O<sub>8</sub> and a fixed exchange rate of \$1.00 US=\$1.00 Cdn was used to estimate mineral reserves. The McArthur River mineral reserves are not significantly sensitive to variances in the uranium price of plus or minus \$20 provided that annual production remains above 10 million pounds U<sub>3</sub>O<sub>8</sub>. The price assumption is based on independent industry and analyst estimates of spot prices and the corresponding long-term prices and reflects our committed and uncommitted sales volumes. For committed sales volumes, the spot and term price assumptions were applied in accordance with the terms of the agreements. For uncommitted sales volumes the same price assumptions were applied using a spot-to-term price ratio of 60-40.

- No known metallurgical, environmental, permitting, legal, title, taxation, socio-economic, political, marketing or other issues are expected to materially affect the above estimates of mineral resources and mineral reserves.
- Mineral resources that are not mineral reserves do not have demonstrated economic viability. Totals may not add due to rounding.

### McArthur River/Key Lake life of mine production, average unit operating costs and capital cost forecasts

(as per technical report)

(as at January 1, 2012)	2012	2013	2014	2015	2016	2017	2018	2019
<b>Production (million lbs)</b>	13.5	13.2	13.1	13.1	13.1	13.1	15.4	15.4
<b>Average operating cost (\$Cdn/lb U<sub>3</sub>O<sub>8</sub>)</b>	16.74	17.26	17.52	17.37	17.64	17.20	15.01	15.37
<b>Total capital costs (\$ millions)</b>	189.3	235.0	285.8	236.8	214.2	151.8	168.7	134.2

(as at January 1, 2012)	2020	2021	2022	2023	2024	2025	2026	2027
<b>Production (million lbs)</b>	15.4	15.4	14.9	14.9	14.9	14.9	14.7	13.5
<b>Average operating cost (\$Cdn/lb U<sub>3</sub>O<sub>8</sub>)</b>	15.28	15.28	15.91	15.99	16.09	17.25	17.47	18.75
<b>Total capital costs (\$ millions)</b>	107.5	109.7	89.6	67.8	65.9	67.5	52.2	58.2

(as at January 1, 2012)	2028	2029	2030	2031	2032	2033	2034	Total
<b>Production (million lbs)</b>	13.3	7.2	7.2	7.1	7.1	4.4	4.5	279.1
<b>Average operating cost (\$Cdn/lb U<sub>3</sub>O<sub>8</sub>)</b>	18.74	31.90	31.23	31.68	31.65	48.29	47.97	19.23
<b>Total capital costs (\$ millions)</b>	55.0	40.2	40.8	36.2	28.5	17.6	11.9	2,464.4

## Rabbit Lake

### Production update

Production remains on track for the year. To ensure the most efficient operation of the mill throughout the year, we continually manage ore supply and, therefore, experience large variations in mill production from quarter to quarter.

### Operations update

We completed the scheduled mill maintenance shutdown this quarter. A short delay in restarting the mill resulted in slightly lower production compared to the third quarter of 2011, although we are maintaining our forecast production of 3.7 million pounds for the year.

We completed our surface exploration drilling program, which returned positive results near the existing mining operations.

## Smith Ranch-Highland and Crow Butte

### Production update

At our US operations, production for the quarter was unchanged compared to the third quarter of 2011. Production for the first nine months was 33% lower compared to the same period last year due to lower production from Smith Ranch-Highland in the first half of the year.

We have decreased our production forecast for the year by 17% to 2.0 million pounds based on the outlook for the approval of new mine units. Our ability to bring new wellfields into production at Smith Ranch-Highland continues to be affected by the lengthened review process to obtain regulatory approvals.

## Operations update

We received approval to produce from mine unit K-North at Smith Ranch-Highland and continue to seek regulatory approvals to proceed with the rest of our expansion plans.

## Inkai

### Production update

Production was 40% higher for the quarter and unchanged for the first nine months compared to the same periods last year. We continue to bring on additional wellfields to maintain some new, typically higher grade, wellfields in the production mix. Production at the Inkai operation steadily improved over the quarter and the facility is now operating at design capacity.

### Operations update

We continue to pursue government approval of an amendment to the resource use contract in order to implement the production increase from blocks 1 and 2 to 5.2 million pounds of  $U_3O_8$  (100% basis).

Delineation drilling at block 3 continues and construction of the test leach facility is underway.

On October 31, 2012, our board of directors approved a binding memorandum of agreement (2012 MOA) with our joint venture partner Kazatomprom setting out a framework to:

- increase Inkai's annual production from blocks 1 and 2 to 10.4 million pounds of uranium concentrate (our share 5.2 million pounds) and sustain it at that level
- extend the term of Inkai's resource use contract through 2045

Kazatomprom is pursuing a strategic objective to develop uranium processing capacity in Kazakhstan to complement its leading uranium mining operations. The 2012 MOA builds on the non-binding memorandum of understanding signed in 2007 to co-operate on the development of uranium conversion capacity, with Kazatomprom's primary focus now being on uranium refining rather than uranium conversion.

The 2012 MOA strengthens our partnership with Kazatomprom and includes a number of connected provisions relating to the increase of Inkai's annual production and extension to the term of Inkai's resource use contract. Under the terms of the 2012 MOA, we agree to:

- adjust our ownership interests in Inkai to 50% on an overall basis after achieving the production increase
- make two milestone payments of \$34 million (US) each – the first after Inkai receives all necessary government approvals to increase uranium production to 10.4 million pounds (100%) annually through 2045, and the second after the increased production target is achieved
- pay to Kazatomprom a royalty of \$5 (US) per pound of uranium concentrate on our share of production above 2.6 million pounds annually from Inkai once Inkai obtains all approvals required for the production increase to 10.4 million pounds (100% basis)
- participate in the construction and operation of a uranium refinery in Kazakhstan with capacity to produce 6,000 tonnes of uranium (tU) as  $UO_3$  annually, where we will own one third of the refinery and the remaining two thirds will be owned by Kazatomprom, with construction to begin by 2018
- provide Kazatomprom with a five-year option to license our proprietary uranium conversion technology for purposes of constructing and operating a  $UF_6$  conversion facility in Kazakhstan
- negotiate with Kazatomprom toward a conversion services agreement for up to 4,000 tU of conversion services annually and/or, for a three-year period, provide an opportunity for Kazatomprom to acquire a one-third interest in our conversion facility in Canada

Under the 2012 MOA, the first steps will be to complete a feasibility study for the production increase, and a prefeasibility study for the uranium refinery. We agree to work with Kazatomprom to pace investments for increasing uranium production to match progress on the transfer of our uranium refining technology and construction of the uranium refinery in Kazakhstan, subject to market conditions.

Implementation of the 2012 MOA is subject to:

- further agreements on a number of issues including agreements governing the ownership, construction and operation of the uranium refinery in Kazakhstan
- approval by Kazatomprom's board of directors
- the receipt of all necessary Canadian and Kazakhstan governmental approvals including all licences and permits required to allow the transfer and licensing of our uranium refining technology

## Development project

### Cigar Lake

We continued to make solid progress at Cigar Lake this quarter.

We have assembled the first jet boring system unit underground and moved it to a production tunnel where we:

- have begun preliminary commissioning
- will begin systems testing
- will prepare to test in waste rock.

In shaft 2 we are installing infrastructure, including a concrete ventilation partition, electrical cable, water services, ore slurry pipes and hoist systems.

We will focus on carrying out the remainder of our 2012 plans and implementing the strategies we outlined in our annual MD&A. We continue to expect first commissioning in ore in mid-2013 and the first packaged pounds in the fourth quarter of 2013.

Cigar Lake is a key part of our plan to increase annual uranium supply, and we are committed to bringing this valuable asset safely into production.

## Projects under evaluation

### Millennium

We have received comments from the regulators on our draft environmental impact statement and are working to address the questions and issues they have raised. We plan to submit the final environmental impact statement in 2013.

We completed the summer exploration drill program and successfully identified additional mineralization at the unconformity.

We will advance this project at a pace aligned with market opportunities and economic circumstances.

### Kintyre

On October 11, 2012, we announced the successful signing of a mine development agreement with the Martu – a key activity in our project planning.

Based on our review of the current market environment, we will complete the value engineering and the environmental permitting in order to maintain the ability to proceed with the project should the market factors improve the economics. However, we have decided not to proceed with the detailed feasibility study at this time.

## Fuel services 2012 Q3 updates

Port Hope conversion services  
Cameco Fuel Manufacturing Inc.  
Springfields Fuels Ltd. (SFL)

### Production update

Fuel services produced 2.1 million kgU in the third quarter, 25% lower than the same period last year. Production for the first nine months of the year was 10.9 million kgU, 6% lower than the same period last year. As a result of the planned reduction in production, results will remain lower than comparable periods in 2011; however, production remains on track for the year.

## Qualified persons

The technical and scientific information discussed in this MD&A for our material properties (McArthur River/Key Lake, Inkai and Cigar Lake) was approved by the following individuals who are qualified persons for the purposes of NI 43-101:

### *McArthur River/Key Lake*

- David Bronkhorst, vice-president, Saskatchewan mining south, Cameco
- Alain Mainville, director, mineral resources management, Cameco
- Les Yesnik, general manager, Key Lake, Cameco
- Gregory Murdock, technical manager, McArthur River, Cameco

### *Cigar Lake*

- Grant Goddard, vice-president, Saskatchewan mining north, Cameco

### *Inkai*

- Dave Neuburger, vice-president, international mining, Cameco

## Additional information

### Related party transactions

We buy significant amounts of goods and services for our Saskatchewan mining operations from northern Saskatchewan suppliers to support economic development in the region. One of these suppliers is Points Athabasca Contracting Ltd. (PACL). In the first nine months of 2012, we paid PACL \$32 million for construction and contracting services (2011 - \$47 million). These transactions were carried out in the normal course of business. A member of Cameco's board of directors is the president of PACL.

### Critical accounting estimates

In our 2011 annual MD&A, we have identified the critical accounting estimates that reflect the more significant judgments used in the preparation of our financial statements. Please refer to note 2 of our interim financial statements for a detailed description of our application of estimates and judgment in the preparation of our financial information.

### Controls and procedures

As of September 30, 2012, we carried out an evaluation under the supervision and with the participation of our management, including our chief executive officer (CEO) and chief financial officer (CFO), of the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

Based upon that evaluation and as of September 30, 2012, the CEO and CFO concluded that:

- the disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under applicable securities laws is recorded, processed, summarized and reported as and when required
- such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure

There has been no change in our internal control over financial reporting during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## **New accounting pronouncements**

### **New standards and interpretations not yet adopted**

We have not yet adopted the standards and amendments to existing standards that have been issued. The standards and amendments, unless otherwise stated, are effective for periods beginning on or after January 1, 2013. Please refer to our 2011 annual MD&A for a brief description of each accounting pronouncement. We are assessing the impact of the following standards and amendments on our financial statements:

- *IFRS 7, Financial Instruments: Disclosures*
- *IFRS 9, Financial Instruments*
- *IFRS 10, Consolidated Financial Statements*
- *IFRS 11, Joint Arrangements*
- *IFRS 12, Disclosure of Interests in Other Entities*
- *IFRS 13, Fair Value Measurement*
- *IAS 1, Presentation of Financial Statements*
- *IAS 19, Employee Benefits*
- *IAS 32, Financial Instruments: Presentation (January 1, 2014)*

**Cameco Corporation**  
**Consolidated Statements of Earnings**

(Unaudited)

(\$Cdn Thousands, except per share amounts)

(Recast -  
note 3(b))

(Recast -  
note 3(b))

	Note	Three Months Ended		Nine Months Ended	
		Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
Revenue from products and services		\$408,397	\$526,952	\$1,363,079	\$1,413,758
Cost of products and services sold		218,131	284,519	770,670	828,142
Depreciation and amortization		55,576	63,376	176,406	162,163
<b>Cost of sales</b>		<b>273,707</b>	<b>347,895</b>	<b>947,076</b>	<b>990,305</b>
<b>Gross profit</b>		<b>134,690</b>	<b>179,057</b>	<b>416,003</b>	<b>423,453</b>
Administration		38,735	38,091	124,164	106,073
Exploration		34,547	31,720	75,404	62,206
Research and development		2,181	2,071	6,159	3,797
Loss (gain) on sale of assets		512	418	(1,637)	1,113
<b>Earnings from operations</b>		<b>58,715</b>	<b>106,757</b>	<b>211,913</b>	<b>250,264</b>
Finance costs	8	(29,716)	(16,385)	(64,735)	(55,946)
Gains (losses) on derivatives	13	53,038	(75,804)	54,612	(40,216)
Finance income		4,746	5,922	16,535	19,037
Share of loss from equity-accounted investees		(1,962)	(1,443)	(4,733)	(5,573)
Other expense		-	(1,614)	(25,745)	(1,061)
<b>Earnings before income taxes</b>		<b>84,821</b>	<b>17,433</b>	<b>187,847</b>	<b>166,505</b>
Income tax expense (recovery)	9	3,250	(21,711)	(32,559)	(18,777)
<b>Net earnings</b>		<b>\$81,571</b>	<b>\$39,144</b>	<b>\$220,406</b>	<b>\$185,282</b>
<b>Net earnings (loss) attributable to:</b>					
Equity holders		\$81,775	\$39,452	\$221,390	\$185,590
Non-controlling interest		(204)	(308)	(984)	(308)
<b>Net earnings</b>		<b>\$81,571</b>	<b>\$39,144</b>	<b>\$220,406</b>	<b>\$185,282</b>
<b>Earnings per common share attributable to equity holders</b>					
Basic	14	\$0.21	\$0.10	\$0.56	\$0.47
Diluted	14	\$0.21	\$0.10	\$0.56	\$0.47

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Comprehensive Income**  
(Unaudited)  
(\$Cdn Thousands)

		(Recast - note 3(b))		(Recast - note 3(b))	
	Note	Three Months Ended		Nine Months Ended	
		Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
<b>Net earnings</b>		<b>\$81,571</b>	<b>\$39,144</b>	<b>\$220,406</b>	<b>\$185,282</b>
Other comprehensive income (loss), net of taxes	9				
Exchange differences on translation of foreign operations		(33,089)	55,268	(36,194)	40,885
Gains (losses) on derivatives designated as cash flow hedges		(1,778)	544	3,911	3,666
Gains on derivatives designated as cash flow hedges transferred to net earnings		(4,108)	(4,062)	(15,941)	(15,294)
Unrealized gains (losses) on available-for-sale assets		70	60	(20)	744
Gains on available-for-sale assets transferred to net earnings		(92)	(8)	(130)	(1,848)
Defined benefit plan actuarial losses		(105,133)	(109,897)	(105,133)	(109,897)
Other comprehensive loss, net of taxes		<b>(144,130)</b>	<b>(58,095)</b>	<b>(153,507)</b>	<b>(81,744)</b>
<b>Total comprehensive income (loss)</b>		<b>\$(62,559)</b>	<b>\$(18,951)</b>	<b>\$66,899</b>	<b>\$103,538</b>
<b>Other comprehensive income (loss) attributable to:</b>					
Equity holders		\$(144,089)	\$(58,416)	\$(153,377)	\$(82,065)
Non-controlling interest		(41)	321	(130)	321
<b>Other comprehensive loss for the period</b>		<b>\$(144,130)</b>	<b>\$(58,095)</b>	<b>\$(153,507)</b>	<b>\$(81,744)</b>
<b>Total comprehensive income (loss) attributable to:</b>					
Equity holders		\$(62,314)	\$(18,964)	\$68,013	\$103,525
Non-controlling interest		(245)	13	(1,114)	13
<b>Total comprehensive income (loss) for the period</b>		<b>\$(62,559)</b>	<b>\$(18,951)</b>	<b>\$66,899</b>	<b>\$103,538</b>

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Financial Position**

(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

	Note	As At	
		Sep 30/12	Dec 31/11
<b>Assets</b>			
Current assets			
Cash and cash equivalents		\$465,536	\$398,084
Short-term investments		198,432	804,141
Accounts receivable		319,801	611,815
Current tax assets		28,049	31,388
Inventories	4	718,820	493,875
Supplies and prepaid expenses		215,233	182,037
Current portion of long-term receivables, investments and other	5	91,042	62,433
<b>Total current assets</b>		<b>2,036,913</b>	<b>2,583,773</b>
Property, plant and equipment			
Intangible assets		4,780,329	4,349,492
Long-term receivables, investments and other	5	95,484	98,954
Investments in equity-accounted investees		304,263	283,818
Deferred tax assets		211,639	220,226
Total non-current assets		170,582	81,392
<b>Total assets</b>		<b>\$7,599,210</b>	<b>\$7,617,655</b>
<b>Liabilities and Shareholders' Equity</b>			
Current liabilities			
Accounts payable and accrued liabilities		\$446,047	\$455,499
Current tax liabilities		17,733	39,330
Short-term debt		62,972	97,830
Dividends payable		39,535	39,475
Current portion of finance lease obligation		15,958	14,852
Current portion of other liabilities	6	18,032	50,495
Current portion of provisions		14,416	14,857
<b>Total current liabilities</b>		<b>614,693</b>	<b>712,338</b>
Long-term debt			
Finance lease obligation		795,655	795,144
Other liabilities	6	118,879	130,982
Provisions		665,985	528,264
Deferred tax liabilities		507,396	519,625
Total non-current liabilities		7,864	8,165
<b>Total non-current liabilities</b>		<b>2,095,779</b>	<b>1,982,180</b>
Shareholders' equity			
Share capital		1,851,474	1,842,289
Contributed surplus		165,156	155,757
Retained earnings		2,872,638	2,874,973
Other components of equity		(1,669)	46,575
<b>Total shareholders' equity attributable to equity holders</b>		<b>4,887,599</b>	<b>4,919,594</b>
Non-controlling interest			
		1,139	3,543
<b>Total shareholders' equity</b>		<b>4,888,738</b>	<b>4,923,137</b>
<b>Total liabilities and shareholders' equity</b>		<b>\$7,599,210</b>	<b>\$7,617,655</b>

Commitments and contingencies [notes 9,12]

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Changes in Equity**  
(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

	Attributable to equity holders						Total	Non-Controlling Interest	Total Equity
	Share Capital	Contributed Surplus	Retained Earnings	Foreign Currency Translation	Cash Flow Hedges	Available-For-Sale Assets			
Balance at January 1, 2012	\$1,842,289	\$155,757	\$2,874,973	\$26,867	\$19,560	\$148	\$4,919,594	\$3,543	\$4,923,137
Net earnings	-	-	221,390	-	-	-	221,390	(984)	220,406
Total other comprehensive loss	-	-	(105,133)	(36,064)	(12,030)	(150)	(153,377)	(130)	(153,507)
<b>Total comprehensive income for the period</b>	-	-	116,257	(36,064)	(12,030)	(150)	68,013	(1,114)	66,899
Share-based compensation	-	13,747	-	-	-	-	13,747	-	13,747
Share options exercised	9,185	(4,348)	-	-	-	-	4,837	-	4,837
Dividends	-	-	(118,592)	-	-	-	(118,592)	-	(118,592)
Change in ownership interests in subsidiary	-	-	-	-	-	-	-	(1,290)	(1,290)
<b>Balance at September 30, 2012</b>	<b>\$1,851,474</b>	<b>\$165,156</b>	<b>\$2,872,638</b>	<b>\$(9,197)</b>	<b>\$7,530</b>	<b>\$(2)</b>	<b>\$4,887,599</b>	<b>\$1,139</b>	<b>\$4,888,738</b>
Balance at January 1, 2011	1,833,257	142,376	2,690,184	(7,276)	30,306	1,793	4,690,640	-	4,690,640
Net earnings	-	-	185,590	-	-	-	185,590	(308)	185,282
Total other comprehensive income (loss)	-	-	(109,897)	40,564	(11,628)	(1,104)	(82,065)	321	(81,744)
<b>Total comprehensive income for the period</b>	-	-	75,693	40,564	(11,628)	(1,104)	103,525	13	103,538
Share-based compensation	-	14,520	-	-	-	-	14,520	-	14,520
Share options exercised	8,582	(6,004)	-	-	-	-	2,578	-	2,578
Dividends	-	-	(118,413)	-	-	-	(118,413)	-	(118,413)
Change in ownership interests in subsidiary	-	-	(3,691)	-	-	-	(3,691)	3,884	193
<b>Balance at September 30, 2011</b>	<b>\$1,841,839</b>	<b>\$150,892</b>	<b>\$2,643,773</b>	<b>\$33,288</b>	<b>\$18,678</b>	<b>\$689</b>	<b>\$4,689,159</b>	<b>\$3,897</b>	<b>\$4,693,056</b>

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Consolidated Statements of Cash Flows**  
(Unaudited)  
(\$Cdn Thousands)

(Recast -  
note 3(b))

(Recast -  
note 3(b))

		Three Months Ended		Nine Months Ended	
	Note	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
<b>Operating activities</b>					
Net earnings		\$81,571	\$39,144	\$220,406	\$185,282
Adjustments for:					
Depreciation and amortization		55,576	63,376	176,406	162,163
Deferred charges		4,788	(927)	(10,852)	(9,113)
Unrealized losses (gains) on derivatives		(48,991)	91,363	(52,267)	101,219
Share-based compensation	11	3,821	3,200	13,747	14,520
Loss (gain) on sale of assets		512	418	(1,637)	1,113
Finance costs	8	29,716	16,385	64,735	55,946
Finance income		(4,746)	(5,922)	(16,535)	(19,037)
Share of loss from equity-accounted investees		1,962	1,443	4,733	5,573
Other income (expense)		-	1,037	(3,796)	(3,053)
Income tax expense (recovery)	9	3,250	(21,711)	(32,559)	(18,777)
Interest received		6,011	6,658	18,241	16,347
Income taxes paid		(2,000)	(6,246)	(55,329)	(54,129)
Income taxes refunded		4,383	24,706	17,546	24,706
Other operating items	10	(92,140)	(20,555)	18,547	23,831
<b>Net cash provided by operations</b>		<b>43,713</b>	<b>192,369</b>	<b>361,386</b>	<b>486,591</b>
<b>Investing activities</b>					
Additions to property, plant and equipment		(212,692)	(179,454)	(664,193)	(443,293)
Decrease in short-term investments		382,764	222,075	605,534	232,821
Decrease (increase) in long-term receivables, investments and other		(467)	11,882	(30,419)	39,376
Proceeds from sale of property, plant and equipment		25	29	3,124	61
<b>Net cash provided by (used in) investing</b>		<b>169,630</b>	<b>54,532</b>	<b>(85,954)</b>	<b>(171,035)</b>
<b>Financing activities</b>					
Increase in debt		2,690	4,533	-	3,459
Decrease in debt		-	-	(43,946)	(9,796)
Interest paid		(24,470)	(24,064)	(51,452)	(51,152)
Proceeds from issuance of shares, stock option plan		693	58	6,997	6,996
Dividends paid		(39,531)	(39,472)	(118,531)	(106,547)
<b>Net cash used in financing</b>		<b>(60,618)</b>	<b>(58,945)</b>	<b>(206,932)</b>	<b>(157,040)</b>
Increase in cash during the period		152,725	187,956	68,500	158,516
Exchange rate changes on foreign currency cash balances		(817)	8,249	(1,048)	7,800
Cash and cash equivalents at beginning of period		313,628	345,491	398,084	375,380
<b>Cash and cash equivalents at end of period</b>		<b>\$465,536</b>	<b>\$541,696</b>	<b>\$465,536</b>	<b>\$541,696</b>
<b>Cash and cash equivalents is comprised of:</b>					
Cash				\$60,550	\$58,446
Cash equivalents				404,986	483,250
				\$465,536	\$541,696

See accompanying notes to condensed consolidated interim financial statements.

**Cameco Corporation**  
**Notes to Condensed Consolidated Interim Financial Statements**

(Unaudited)

(\$Cdn thousands except per share amounts and as noted)

**1. Cameco Corporation**

Cameco Corporation is incorporated under the Canada Business Corporations Act. The address of its registered office is 2121 11<sup>th</sup> Street West, Saskatoon, Saskatchewan, S7M 1J3. The condensed consolidated interim financial statements as at and for the period ended September 30, 2012 comprise Cameco Corporation and its subsidiaries (collectively, the “Company” or “Cameco”) and the Company’s interest in associates and joint ventures. The Company is primarily engaged in the exploration for and the development, mining, refining, conversion and fabrication of uranium for sale as fuel for generating electricity in nuclear power reactors in Canada and other countries. Cameco has a 31.6% interest in Bruce Power L.P. (“BPLP”), which operates the four Bruce B nuclear reactors in Ontario.

**2. Significant Accounting Policies**

**(a) Statement of Compliance**

These condensed consolidated interim financial statements have been prepared in accordance with IAS 34, *Interim Financial Reporting*. The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with Cameco’s annual consolidated financial statements as at and for the year ended December 31, 2011.

These condensed consolidated interim financial statements were authorized for issuance by the Company’s board of directors on October 31, 2012.

**(b) Basis of Presentation**

These condensed consolidated interim financial statements are presented in Canadian dollars, which is the Company’s functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand except where otherwise noted.

The condensed consolidated interim financial statements have been prepared on the historical cost basis except for the following material items in the statement of financial position: derivative financial instruments, available-for-sale financial assets and liabilities for cash-settled share-based payment arrangements are measured at fair value and the defined benefit asset is recognized as plan assets, plus unrecognized past service cost, less the present value of the defined benefit obligation.

The preparation of the condensed consolidated interim financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may vary from these estimates.

In preparing these condensed consolidated interim financial statements, the significant judgments made by management in applying the Company’s accounting policies and key sources of estimation uncertainty were the same as those that applied to the consolidated financial statements as at and for the year ended December 31, 2011.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements are disclosed in note 6 of the December 31, 2011 consolidated financial statements.

**3. Accounting Changes**

**(a) New Standards and Interpretations not yet Adopted**

The Company has not yet adopted the standards and amendments to existing standards that have been issued. The standards and amendments, unless otherwise stated, are effective for periods beginning on or after January 1, 2013. Cameco is assessing the impact of the following standards and amendments on its financial statements:

**(i) Financial Instruments**

In October 2010, the International Accounting Standards Board (“IASB”) issued IFRS 9, *Financial Instruments* (“IFRS 9”). This standard is part of a wider project to replace IAS 39, *Financial Instruments: Recognition and Measurement* (“IAS 39”). IFRS 9 replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The basis of classification depends on the entity’s business model and the contractual cash flow

characteristics of the financial asset or liability. The guidance in IAS 39 on impairment of financial assets and hedge accounting continues to apply.

**(ii) Consolidated Financial Statements**

In May 2011, the IASB issued IFRS 10, *Consolidated Financial Statements* (“IFRS 10”). This standard establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 defines the principle of control and establishes control as the basis for determining which entities are consolidated in the consolidated financial statements.

**(iii) Joint Arrangements**

In May 2011, the IASB issued IFRS 11, *Joint Arrangements* (“IFRS 11”). This standard establishes principles for financial reporting by parties to a joint arrangement. IFRS 11 requires a party to assess the rights and obligations arising from an arrangement in determining whether an arrangement is either a joint venture or a joint operation. Joint ventures are to be accounted for using the equity method while joint operations will continue to be accounted for using proportionate consolidation.

**(iv) Disclosure of Interests in Other Entities**

In May 2011, the IASB issued IFRS 12, *Disclosure of Interests in Other Entities* (“IFRS 12”). This standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 integrates and makes consistent the disclosure requirements for a reporting entity’s interest in other entities and presents those requirements in a single standard.

**(v) Fair Value Measurement**

In May 2011, the IASB issued IFRS 13, *Fair Value Measurement* (“IFRS 13”). This standard provides additional guidance where IFRS requires fair value to be used. IFRS 13 defines fair value, sets out in a single standard a framework for measuring fair value and establishes the required disclosures about fair value measurements.

**(vi) Employee Benefits**

In June 2011, the IASB issued an amended version of IAS 19, *Employee Benefits* (“IAS 19”). This amendment eliminates the ‘corridor method’ of accounting for defined benefit plans. Revised IAS 19 also streamlines the presentation of changes in assets and liabilities arising from defined benefit plans, and enhances the disclosure requirements for defined benefit plans.

**(vii) Presentation of Other Comprehensive Income (“OCI”)**

In June 2011, the IASB issued an amended version of IAS 1, *Presentation of Financial Statements* (“IAS 1”). This amendment is effective for annual periods beginning on or after July 1, 2012 and requires companies preparing financial statements in accordance with IFRS to group together items within OCI that may be reclassified to the profit or loss section of the statement of earnings. Revised IAS 1 also reaffirms existing requirements that items in OCI and profit or loss should be presented as either a single statement or two consecutive statements.

**(viii) Financial Assets and Financial Liabilities**

In December 2011, the IASB issued amendments to IAS 32, *Financial Instruments: Presentation* (“IAS 32”) and IFRS 7, *Financial Instruments: Disclosures* (“IFRS 7”). The amendments are effective for periods beginning on or after January 1, 2013 for IFRS 7 and January 1, 2014 for IAS 32 and are to be applied retrospectively. These amendments clarify matters regarding offsetting financial assets and financial liabilities as well as related disclosure requirements.

**(b) Accounting for Kintyre**

In August 2008, Cameco acquired a 70% interest in the Kintyre exploration project in Australia. The Company previously consolidated its investment in Kintyre on the basis that it was able to exercise control over the asset. In the second quarter of 2012, the Company reconsidered the accounting treatment applied to Kintyre and concluded that consolidation of the investment was not appropriate and only Cameco's interest in the assets and liabilities of Kintyre should be recognized. Accordingly, the non-controlling interest in the assets, liabilities and expenses has been removed from the financial statements. The change in accounting has been applied retrospectively and the comparative statements for 2011 have been recast. There was no impact on retained earnings or net earnings attributable to equity holders for any of the recast periods. The most significant changes relate to a reduction of property, plant and equipment of \$182,615,000 and a reduction of the non-controlling interest on the statement of changes in financial position of \$182,395,000.

**4. Inventories**

	Sep 30/12	Dec 31/11
<b>Uranium</b>		
Concentrate	\$524,304	\$361,481
Broken ore	39,553	14,310
	563,857	375,791
<b>Fuel Services</b>	154,963	118,084
<b>Total</b>	<b>\$718,820</b>	<b>\$493,875</b>

**5. Long-Term Receivables, Investments and Other**

	Sep 30/12	Dec 31/11
<b>BPLP</b>		
Capital lease receivable from Bruce A Limited Partnership ("BALP") <sup>(a)</sup>	\$83,140	\$87,785
Derivatives [note 13]	28,287	54,010
Available-for-sale securities		
GoviEx Uranium (privately held)	20,367	21,057
Derivatives [note 13]	48,144	17,392
Advances receivable from Inkai JV LLP [note 16]	96,332	78,058
Investment tax credits	66,699	54,038
Other	52,336	33,911
	395,305	346,251
Less current portion	(91,042)	(62,433)
<b>Net</b>	<b>\$304,263</b>	<b>\$283,818</b>

<sup>(a)</sup> BPLP leases the Bruce A nuclear generating plants and other property, plant and equipment to BALP under a sublease agreement. Future minimum base rent sublease payments under the capital lease receivable are imputed using a 7.5% discount rate.

## 6. Other Liabilities

	Sep 30/12	Dec 31/11
BPLP		
Accrued pension and post-retirement benefit liability	\$617,472	\$468,363
Derivatives [note 13]	11,270	19,439
Ontario Power Generation ("OPG") loan	2,907	4,045
Deferred sales	10,175	13,739
Derivatives [note 13]	5,400	28,499
Accrued pension and post-retirement benefit liability	30,345	38,050
Other	6,448	6,624
	684,017	578,759
Less current portion	(18,032)	(50,495)
<b>Total</b>	<b>\$665,985</b>	<b>\$528,264</b>

## 7. Share Capital

- (a) At September 30, 2012, there were 395,349,044 common shares outstanding.
- (b) Options in respect of 9,639,467 shares are outstanding under the stock option plan and are exercisable up to 2019. For the quarter ended September 30, 2012, 35,766 options were exercised resulting in the issuance of shares (2011 – 3,800). For the nine months ended September 30, 2012, 603,621 options were exercised resulting in the issuance of shares (2011 – 363,840).

## 8. Finance Costs

	Three Months Ended		Nine Months Ended	
	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
Interest on long-term debt	\$14,439	\$14,305	\$40,272	\$42,447
Unwinding of discount on provisions	3,396	3,240	10,172	9,978
Other charges	1,546	83	5,590	2,223
Foreign exchange losses (gains)	10,017	(1,844)	7,271	(527)
Interest on short-term debt	318	601	1,430	1,825
<b>Total</b>	<b>\$29,716</b>	<b>\$16,385</b>	<b>\$64,735</b>	<b>\$55,946</b>

## 9. Income Taxes

	Three Months Ended		Nine Months Ended	
	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
Earnings (loss) before income taxes				
Canada	\$(1,557)	\$(185,682)	\$(165,901)	\$(260,300)
Foreign	86,378	203,115	353,748	426,805
	<b>\$84,821</b>	<b>\$17,433</b>	<b>\$187,847</b>	<b>\$166,505</b>
Current income taxes (recovery)				
Canada	\$(1,841)	\$(10,422)	\$(1,307)	\$(10,847)
Foreign	5,713	9,866	19,936	27,002
	<b>\$3,872</b>	<b>\$(556)</b>	<b>\$18,629</b>	<b>\$16,155</b>
Deferred income taxes (recovery)				
Canada	\$4,829	\$(25,676)	\$(40,578)	\$(42,433)
Foreign	(5,451)	4,521	(10,610)	7,501
	<b>\$(622)</b>	<b>\$(21,155)</b>	<b>\$(51,188)</b>	<b>\$(34,932)</b>
<b>Income tax expense (recovery)</b>	<b>\$3,250</b>	<b>\$(21,711)</b>	<b>\$(32,559)</b>	<b>\$(18,777)</b>

In 2008, as part of the ongoing annual audits of Cameco's Canadian tax returns, Canada Revenue Agency ("CRA") disputed the transfer pricing methodology used by Cameco and its wholly owned Swiss subsidiary, Cameco Europe Ltd. ("CEL"), in respect of sale and purchase agreements for uranium products. From December 2008 to date, CRA issued notices of reassessment for the taxation years 2003, 2004, 2005 and 2006, which have increased Cameco's income for Canadian income tax purposes by approximately \$43,000,000, \$108,000,000, \$197,000,000 and \$243,000,000 respectively. No reassessment received to date has resulted in more than a nominal amount of cash taxes becoming payable due to the availability of elective deductions and tax loss carrybacks. Cameco believes it is likely that CRA will reassess Cameco's tax returns for subsequent years on a similar basis.

CRA's Transfer Pricing Review Committee has not imposed a transfer pricing penalty for any year reassessed to date.

Having regard to advice from its external advisors, Cameco's opinion is that CRA's position is incorrect, and Cameco is contesting CRA's position. However, to reflect the uncertainties of CRA's appeals process and litigation, Cameco has recorded a cumulative tax provision related to this matter for the years 2003 through the current period in the amount of \$60,000,000. No provisions for penalties or interest have been recorded. Cameco does not expect more than a nominal amount of cash taxes to be payable due to the availability of elective deductions and tax loss carryovers. While the resolution of this matter may result in liabilities that are higher or lower than the reserve, management believes that the ultimate resolution will not be material to Cameco's financial position, results of operations or liquidity over the period. However, an unfavourable outcome for the years 2003 to 2012 could be material to Cameco's financial position, results of operations or cash flows in the year(s) of resolution.

Further to Cameco's decision to contest CRA's reassessments, Cameco is pursuing its appeal rights under the Income Tax Act.

Other comprehensive income included on the consolidated statements of comprehensive income and the consolidated statements of changes in equity is presented net of income taxes. The following income tax amounts are included in each component of other comprehensive income:

**For the three months ended September 30, 2012**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$(33,089)	\$ -	\$(33,089)
Losses on derivatives designated as cash flow hedges	(2,370)	592	(1,778)
Gains on derivatives designated as cash flow hedges transferred to net earnings	(5,477)	1,369	(4,108)
Unrealized gains on available-for-sale assets	81	(11)	70
Gains on available-for-sale assets transferred to net earnings	(106)	14	(92)
Defined benefit plan actuarial losses	(140,178)	35,045	(105,133)
	<b>\$(181,139)</b>	<b>\$37,009</b>	<b>\$(144,130)</b>

**For the three months ended September 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$55,268	\$ -	\$55,268
Gains on derivatives designated as cash flow hedges	725	(181)	544
Gains on derivatives designated as cash flow hedges transferred to net earnings	(5,531)	1,469	(4,062)
Unrealized gains on available-for-sale assets	69	(9)	60
Gains on available-for-sale assets transferred to net earnings	(9)	1	(8)
Defined benefit plan actuarial losses	(146,529)	36,632	(109,897)
	<b>\$(96,007)</b>	<b>\$37,912</b>	<b>\$(58,095)</b>

**For the nine months ended September 30, 2012**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$(36,194)	\$ -	\$(36,194)
Gains on derivatives designated as cash flow hedges	5,214	(1,303)	3,911
Gains on derivatives designated as cash flow hedges transferred to net earnings	(21,254)	5,313	(15,941)
Unrealized losses on available-for-sale assets	(25)	5	(20)
Gains on available-for-sale assets transferred to net earnings	(150)	20	(130)
Defined benefit plan actuarial losses	(140,178)	35,045	(105,133)
	<b>\$(192,587)</b>	<b>\$39,080</b>	<b>\$(153,507)</b>

**For the nine months ended September 30, 2011**

	Before tax	Income tax recovery (expense)	Net of tax
Exchange differences on translation of foreign operations	\$40,885	\$ -	\$40,885
Gains on derivatives designated as cash flow hedges	4,998	(1,332)	3,666
Gains on derivatives designated as cash flow hedges transferred to net earnings	(20,872)	5,578	(15,294)
Unrealized gains on available-for-sale assets	860	(116)	744
Gains on available-for-sale assets transferred to net earnings	(2,129)	281	(1,848)
Defined benefit plan actuarial losses	(146,529)	36,632	(109,897)
	<b>\$(122,787)</b>	<b>\$41,043</b>	<b>\$(81,744)</b>

**10. Statements of Cash Flows  
Other Operating Items**

	Three Months Ended		Nine Months Ended	
	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
Changes in non-cash working capital:				
Accounts receivable	\$(3,059)	\$(60,949)	\$292,043	\$168,701
Inventories	(130,183)	(548)	(193,221)	(117,127)
Supplies and prepaid expenses	(17,438)	(8,509)	(33,633)	(12,549)
Accounts payable and accrued liabilities	60,339	40,465	(10,131)	600
Other	(1,799)	8,986	(36,511)	(15,794)
<b>Total</b>	<b>\$(92,140)</b>	<b>\$(20,555)</b>	<b>\$18,547</b>	<b>\$23,831</b>

**11. Share-Based Compensation Plans**

The Company has the following equity-settled plans:

**(a) Stock Option Plan**

The Company has established a stock option plan under which options to purchase common shares may be granted to employees of Cameco. Options granted under the stock option plan have an exercise price of not less than the closing price quoted on the TSX for the common shares of Cameco on the trading day prior to the date on which the option is granted. The options vest over three years and expire eight years from the date granted.

The aggregate number of common shares that may be issued pursuant to the Cameco stock option plan shall not exceed 43,017,198, of which 27,090,440 shares have been issued.

**(b) Executive Performance Share Unit ("PSU")**

The Company has established a PSU plan whereby it provides each plan participant an annual grant of PSUs in an amount determined by the board. Each PSU represents one phantom common share that entitles the participant to a payment of one Cameco common share purchased on the open market, or cash at the board's discretion, at the end of each three-year period if certain performance and vesting criteria have been met. The final value of the PSUs will be based on the value of Cameco common shares at the end of the three-year period and the number of PSUs that ultimately vest. Vesting of PSUs at the end of the three-year period will be based on total shareholder return over the three years, Cameco's ability to meet its annual cash flow from operations targets and whether the participating executive remains employed by Cameco at the end of the three-year vesting period.

**(c) Executive Restricted Share Unit (“RSU”)**

In 2011, the Company established an RSU plan whereby it provides each plan participant a grant of RSUs in an amount determined by the board. Each RSU represents one phantom common share that entitles the participant to a payment of one Cameco common share purchased on the open market, or cash at the board’s discretion. The final value of the RSUs will be based on the value of Cameco common shares at the end of the three-year vesting period.

Cameco records compensation expense with an offsetting credit to contributed surplus to reflect the estimated fair value of the equity-settled share-based compensation plans granted to employees.

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>Sep 30/12</b>	<b>Sep 30/11</b>	<b>Sep 30/12</b>	<b>Sep 30/11</b>
Stock option plan	\$2,605	\$2,350	\$11,661	\$11,970
Performance share unit	1,068	850	1,641	2,550
Restricted share unit	148	-	445	-
<b>Total</b>	<b>\$3,821</b>	<b>\$3,200</b>	<b>\$13,747</b>	<b>\$14,520</b>

The fair value of the units granted through the PSU plan was determined based on Monte Carlo simulation. The fair value of all other share-based payment plans was measured based on the Black-Scholes option-pricing model. Expected volatility is estimated by considering historic average share price volatility. The inputs used in the measurement of the fair values at grant date were as follows:

	<b>Stock Option Plan</b>	<b>PSUs</b>
Number of options granted	2,097,573	178,640
Average strike price	\$21.14	-
Expected dividend	\$0.40	\$0.40
Expected volatility	47%	36%
Risk-free interest rate	1.4%	1.4%
Expected life of option	4.3 years	3 years
Expected forfeitures	10%	0%
Weighted average grant date fair values	\$7.21	\$20.05

In addition to these inputs, other features of the PSU grant were incorporated into the measurement of fair value. The market condition based on total shareholder return was incorporated by utilizing a Monte Carlo simulation. The non-market criteria relating to realized selling prices, production targets and cost control have been incorporated into the valuation at grant date by reviewing prior history and corporate budgets.

## 12. Commitments and Contingencies

- (a) On May 16, 2012, Cameco, Cameco Bruce Holdings II Inc., BPC Generation Infrastructure Trust (“BPC”) and TransCanada Pipelines Limited (“TransCanada”) (collectively, the "Consortium") received an arbitration award against British Energy Limited and British Energy International Holdings Limited (collectively, “BE”) ruling in favour of the Consortium on the issues of repair costs and lost revenue for breach of a representation and warranty contained in the February 14, 2003 Amended and Restated Master Purchase Agreement under which the Consortium acquired BE’s interest in BPLP. The Consortium and BE are in discussions over the quantification of the damages under the arbitrators award. If these issues are not resolved, they will be referred back to the arbitrator for a final decision. The Company recorded an estimate of the expected net proceeds.

In connection with this arbitration, BE issued on February 10, 2006, and then served on OPG and BPLP a Statement of Claim. This Statement of Claim seeks damages for any amounts that BE is found liable to pay to the Consortium in connection with the Unit 8 steam generator arbitration described above, additional damages in the amount of \$500,000,000, costs and pre and post judgment interest amongst other things. Further proceedings in this action are on hold pending final disposition of the arbitration award.

- (b) Annual supplemental rents of \$30,000,000 (subject to CPI) per operating reactor are payable by BPLP to OPG. Should the hourly annual average price of electricity in Ontario fall below \$30 per megawatt hour for any calendar year, the supplemental rent reduces to \$12,000,000 per operating reactor. During 2012, BPLP recognized an amount receivable of \$58,000,000 and a related reduction to lease expense, with Cameco’s share being \$18,300,000.
- (c) Cameco, TransCanada and BPC have assumed the obligations to provide financial guarantees on behalf of BPLP. Cameco has provided the following financial assurances, with varying terms that range from 2012 to 2018:
- i) Guarantees to customers under power sales agreements of up to \$4,300,000. At September 30, 2012, Cameco’s actual exposure under these agreements was \$300,000.
  - ii) Termination payments to OPG pursuant to the lease agreement of \$58,300,000. The fair value of these guarantees is nominal.
- (d) Under a supply contract with the Ontario Power Authority (“OPA”), BPLP is entitled to receive payments from the OPA during periods when the market price for electricity in Ontario is lower than the floor price defined under the agreement during a calendar year. On July 6, 2009, BPLP and the OPA amended the supply contract such that beginning in 2009, the annual payments received will not be subject to repayment in future years. Previously, the payments received under the agreement were subject to repayment during the entire term of the contract, dependent on the spot price in future periods. BPLP’s entitlement to receive these payments remains in effect until December 31, 2019 but the generation that is subject to these payments starts to decrease in 2016, reflecting the original estimated lives for the Bruce B units. During 2012, BPLP recorded \$575,000,000 under this agreement which was recognized as revenue with Cameco’s share being \$181,700,000.

### 13. Derivatives

The following tables summarize the fair value of derivatives and classification on the statements of financial position:

#### As at September 30, 2012

	Comeco	BPLP	Total
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$64	\$5,523	\$5,587
Foreign currency contracts	38,544	-	38,544
Interest rate contracts	4,136	-	4,136
Cash flow hedges:			
Energy and sales contracts	-	11,494	11,494
<b>Net</b>	<b>\$42,744</b>	<b>\$17,017</b>	<b>\$59,761</b>
Classification:			
Current portion of long-term receivables, investments and other [note 5]	\$42,462	\$22,410	\$64,872
Long-term receivables, investments and other [note 5]	5,682	5,877	11,559
Current portion of other liabilities [note 6]	(3,918)	(9,365)	(13,283)
Other liabilities [note 6]	(1,482)	(1,905)	(3,387)
<b>Net</b>	<b>\$42,744</b>	<b>\$17,017</b>	<b>\$59,761</b>

#### As at December 31, 2011

	Comeco	BPLP	Total
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(639)	\$8,033	\$7,394
Foreign currency contracts	(17,633)	-	(17,633)
Interest rate contracts	7,165	-	7,165
Cash flow hedges:			
Energy and sales contracts	-	26,538	26,538
<b>Net</b>	<b>\$(11,107)</b>	<b>\$34,571</b>	<b>\$23,464</b>
Classification:			
Current portion of long-term receivables, investments and other [note 5]	\$8,922	\$42,088	\$51,010
Long-term receivables, investments and other [note 5]	8,470	11,922	20,392
Current portion of other liabilities [note 6]	(26,555)	(16,913)	(43,468)
Other liabilities [note 6]	(1,944)	(2,526)	(4,470)
<b>Net</b>	<b>\$(11,107)</b>	<b>\$34,571</b>	<b>\$23,464</b>

The following tables summarize different components of the gains (losses) on derivatives:

**For the three months ended September 30, 2012**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$(63)	\$(1,573)	\$(1,636)
Foreign currency contracts	55,248	-	55,248
Interest rate contracts	(215)	-	(215)
Cash flow hedges:			
Energy and sales contracts	-	(359)	(359)
<b>Net</b>	<b>\$54,970</b>	<b>\$(1,932)</b>	<b>\$53,038</b>

**For the three months ended September 30, 2011**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$697	\$(1,884)	\$(1,187)
Foreign currency contracts	(79,999)	-	(79,999)
Interest rate contracts	6,009	-	6,009
Cash flow hedges:			
Energy and sales contracts	-	(627)	(627)
<b>Net</b>	<b>\$(73,293)</b>	<b>\$(2,511)</b>	<b>\$(75,804)</b>

**For the nine months ended September 30, 2012**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$62	\$20	\$82
Foreign currency contracts	56,682	-	\$56,682
Interest rate contracts	(619)	-	\$(619)
Cash flow hedges:			
Energy and sales contracts	-	(1,533)	\$(1,533)
<b>Net</b>	<b>\$56,125</b>	<b>\$(1,513)</b>	<b>\$54,612</b>

**For the nine months ended September 30, 2011**

	<b>Cameco</b>	<b>BPLP</b>	<b>Total</b>
Non-hedge derivatives:			
Embedded derivatives - sales contracts	\$2,069	\$(1,746)	\$323
Foreign currency contracts	(46,339)	-	(46,339)
Interest rate contracts	7,882	-	7,882
Cash flow hedges:			
Energy and sales contracts	-	(2,082)	(2,082)
<b>Net</b>	<b>\$(36,388)</b>	<b>\$(3,828)</b>	<b>\$(40,216)</b>

Over the next 12 months, based on current exchange rates, Cameco expects an estimated \$9,100,000 of pre-tax gains from BPLP's various energy and sales related cash flow hedges to be reclassified through other comprehensive income to net earnings. The maximum length of time BPLP is hedging its exposure to the variability in future cash flows related to electricity prices on future transactions is six years.

#### 14. Earnings Per Share

Per share amounts have been calculated based on the weighted average number of common shares outstanding during the period. The weighted average number of paid shares outstanding in 2012 was 395,195,455 (2011 – 394,642,475).

	Three Months Ended		Nine Months Ended	
	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
<b>Basic earnings per share computation</b>				
Net earnings attributable to equity holders	\$81,775	\$39,452	\$221,390	\$185,590
	395,341	394,712	395,195	394,642
<b>Basic earnings per common share</b>	<b>\$0.21</b>	<b>\$0.10</b>	<b>\$0.56</b>	<b>\$0.47</b>
<b>Diluted earnings per share computation</b>				
Net earnings attributable to equity holders	\$81,775	\$39,452	\$221,390	\$185,590
Weighted average common shares outstanding	395,341	394,712	395,195	394,642
Dilutive effect of stock options	162	474	604	994
Weighted average common shares outstanding, assuming dilution	395,503	395,186	395,799	395,636
<b>Diluted earnings per common share</b>	<b>\$0.21</b>	<b>\$0.10</b>	<b>\$0.56</b>	<b>\$0.47</b>

## 15. Segmented Information

Cameco has three reportable segments: uranium, fuel services and electricity. The uranium segment involves the exploration for, mining, milling, purchase and sale of uranium concentrate. The fuel services segment involves the refining, conversion and fabrication of uranium concentrate and the purchase and sale of conversion services. The electricity segment involves the generation and sale of electricity.

Cameco's reportable segments are strategic business units with different products, processes and marketing strategies.

Accounting policies used in each segment are consistent with the policies outlined in the most recent annual consolidated financial statements. Segment revenues, expenses and results include transactions between segments incurred in the ordinary course of business. These transactions are priced on an arm's length basis and are eliminated on consolidation.

### (a) Business Segments

#### For the three months ended September 30, 2012

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$230,754	\$55,659	\$121,439	\$545	\$408,397
Expenses					
Cost of products and services sold	121,764	48,574	47,720	73	218,131
Depreciation and amortization	25,701	4,538	20,106	5,231	55,576
<b>Cost of sales</b>	<b>147,465</b>	<b>53,112</b>	<b>67,826</b>	<b>5,304</b>	<b>273,707</b>
<b>Gross profit (loss)</b>	<b>83,289</b>	<b>2,547</b>	<b>53,613</b>	<b>(4,759)</b>	<b>134,690</b>
Exploration	34,547	-	-	-	34,547
Loss on sale of assets	512	-	-	-	512
Share of loss from equity-accounted investees	1,173	789	-	-	1,962
Non-segmented expenses					12,848
<b>Earnings (loss) before income taxes</b>	<b>47,057</b>	<b>1,758</b>	<b>53,613</b>	<b>(4,759)</b>	<b>84,821</b>
Income tax expense					3,250
<b>Net earnings</b>					<b>\$81,571</b>

**For the three months ended September 30, 2011**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$331,500	\$80,563	\$114,266	\$623	\$526,952
Expenses					
Cost of products and services sold	164,704	64,816	54,926	73	284,519
Depreciation and amortization	34,278	6,089	18,455	4,554	63,376
<b>Cost of sales</b>	<b>198,982</b>	<b>70,905</b>	<b>73,381</b>	<b>4,627</b>	<b>347,895</b>
<b>Gross profit (loss)</b>	<b>132,518</b>	<b>9,658</b>	<b>40,885</b>	<b>(4,004)</b>	<b>179,057</b>
Exploration	31,720	-	-	-	31,720
Loss on sale of assets	418	-	-	-	418
Share of loss from equity-accounted investees	686	757	-	-	1,443
Other expense	1,614	-	-	-	1,614
Non-segmented expenses					126,429
<b>Earnings (loss) before income taxes</b>	<b>98,080</b>	<b>8,901</b>	<b>40,885</b>	<b>(4,004)</b>	<b>17,433</b>
Income tax recovery					(21,711)
<b>Net earnings</b>					<b>\$39,144</b>

**For the nine months ended September 30, 2012**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$837,335	\$178,111	\$345,957	\$1,676	\$1,363,079
Expenses					
Cost of products and services sold	480,582	140,811	149,058	219	770,670
Depreciation and amortization	89,520	14,645	59,053	13,188	176,406
<b>Cost of sales</b>	<b>570,102</b>	<b>155,456</b>	<b>208,111</b>	<b>13,407</b>	<b>947,076</b>
<b>Gross profit (loss)</b>	<b>267,233</b>	<b>22,655</b>	<b>137,846</b>	<b>(11,731)</b>	<b>416,003</b>
Exploration	75,404	-	-	-	75,404
Gain on sale of assets	(1,637)	-	-	-	(1,637)
Share of loss from equity-accounted investees	2,449	2,284	-	-	4,733
Other expense	35,745	-	-	-	35,745
Non-segmented expenses					113,911
<b>Earnings (loss) before income taxes</b>	<b>155,272</b>	<b>20,371</b>	<b>137,846</b>	<b>(11,731)</b>	<b>187,847</b>
Income tax recovery					(32,559)
<b>Net earnings</b>					<b>\$220,406</b>

**For the nine months ended September 30, 2011**

	Uranium	Fuel Services	Electricity	Other	Total
Revenue	\$885,069	\$199,418	\$320,898	\$8,373	\$1,413,758
Expenses					
Cost of products and services sold	487,495	153,904	179,755	6,988	828,142
Depreciation and amortization	79,077	16,528	53,013	13,545	162,163
<b>Cost of sales</b>	<b>566,572</b>	<b>170,432</b>	<b>232,768</b>	<b>20,533</b>	<b>990,305</b>
<b>Gross profit (loss)</b>	<b>318,497</b>	<b>28,986</b>	<b>88,130</b>	<b>(12,160)</b>	<b>423,453</b>
Exploration	62,206	-	-	-	62,206
Loss on sale of assets	1,113	-	-	-	1,113
Share of loss from equity-accounted investees	3,665	1,908	-	-	5,573
Other expense	1,061	-	-	-	1,061
Non-segmented expenses					186,995
<b>Earnings (loss) before income taxes</b>	<b>250,452</b>	<b>27,078</b>	<b>88,130</b>	<b>(12,160)</b>	<b>166,505</b>
Income tax recovery					(18,777)
<b>Net earnings</b>					<b>\$185,282</b>

**16. Related Parties**

The shares of Cameco are widely held and no shareholder, resident in Canada, is allowed to own more than 25% of the Company's outstanding common shares, either individually or together with associates. A non-resident of Canada is not allowed to own more than 15%.

**Transactions with Key Management Personnel**

Key management personnel are those persons that have the authority and responsibility for planning, directing and controlling the activities of the Company, directly or indirectly. Key management personnel of the Company include executive officers, vice-presidents, other senior managers and members of the board of directors.

Certain key management personnel, or their related parties, hold positions in other entities that result in them having control or significant influence over the financial or operating policies of those entities. As noted below, one of these entities transacted with the Company in the reporting period. The terms and conditions of the transactions were on an arm's length basis.

Cameco purchases a significant amount of goods and services for its Saskatchewan mining operations from northern Saskatchewan suppliers to support economic development in the region. One such supplier is Points Athabasca Contracting Ltd. and the president of the company became a member of the board of directors of Cameco during 2009. In 2012, Cameco paid Points Athabasca Contracting Ltd. \$32,200,000 (2011 - \$46,900,000) for construction and contracting services. The transactions were conducted in the normal course of business and were accounted for at the exchange amount. Accounts payable include a balance of \$400,000 (2011 - \$3,700,000).

## Other Related Party Transactions

	Transaction Value Three Months Ended		Transaction Value Nine Months Ended		Balance Outstanding As at	
	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11	Sep 30/12	Sep 30/11
<b>Sale of goods and services</b>						
Jointly Controlled Entities						
BPLP <sup>(a)</sup>	\$20,271	\$10,527	\$58,838	\$32,744	\$13,580	\$10,816
<b>Other</b>						
Jointly Controlled Entities						
Interest income (Inkai) <sup>(a)</sup>	600	522	1,671	1,725	96,332	90,103
Associates						
Interest expense	(135)	(444)	(806)	(1,479)	(49,187)	(83,205)

<sup>(a)</sup> Disclosures in respect of transactions with jointly controlled entities represent the amount of such transactions which do not eliminate on proportionate consolidation.

Cameco has entered into fuel supply agreements with BPLP for the procurement of fabricated fuel. Under these agreements, Cameco will supply uranium, conversion services and fabrication services. Contract terms are at market rates and on normal trade terms.

Through an unsecured shareholder loan, Cameco has agreed to fund the development of the Inkai project. The limit on the advances of the loan facility is currently \$258,150,000 (US) and it bears interest at a rate of LIBOR plus 2%. At September 30, 2012, \$244,800,000 (US) of principal and interest was outstanding (December 31, 2011 - \$191,900,000 (US)). At September 30, 2012 the remaining funds available for advance under the facility was \$14,200,000 (US) (December 31, 2011 - \$14,200,000 (US)).

In 2008, a promissory note in the amount of \$73,344,000 (US) was issued to finance the acquisition of GE-Hitachi Global Laser Enrichment LLC ("GLE"). The promissory note is payable on demand and bears interest at market rates. At September 30, 2012, \$50,000,000 (US) of principal and interest was outstanding (December 31, 2011 - \$72,200,000 (US)).

### 17. NUKEM Energy GmbH ("NUKEM")

On May 14, 2012, Cameco entered into an agreement with Advent International ("Advent") to purchase NUKEM, one of the world's leading traders and brokers of nuclear fuel products and services, for cash proceeds of \$136,000,000 (US) and the assumption of their debt. The agreement includes provisions that would provide Advent with a share of NUKEM's future earnings under certain conditions until the end of 2014. The agreement is subject to regulatory approvals and is expected to close in the fourth quarter of 2012.

### 18. Millennium Project Agreement

On June 11, 2012, Cameco acquired a 27.94% interest in the Millennium project from AREVA Resources Canada Inc. ("AREVA") for \$150,000,000, increasing its ownership to 69.9%. The remaining 30.1% is owned by JCU (Canada) Exploration Co. The Millennium project is a proposed uranium mine located in the Athabasca Basin of northern Saskatchewan. The terms of the purchase agreement provides AREVA with a 4% royalty on revenue from 27.94% of any production that exceeds 63,000,000 pounds U<sub>3</sub>O<sub>8</sub> from this project.

**19. Yeelirrie Uranium Project**

On August 26, 2012, Cameco entered into an agreement with BHP Billiton to purchase the Yeelirrie uranium project in Western Australia for \$430,000,000 (US). The Yeelirrie uranium project is a near-surface calcrete-style deposit, amenable to open pit mining techniques. The agreement is subject to regulatory approvals and is expected to close by the end of 2012. Upon closing, stamp duty of approximately \$22,000,000 (US) will be payable by Cameco to the government of Western Australia.

**20. Comparative Figures**

Certain prior period balances have been reclassified to conform to the current financial statement presentation.