

TSX: CCO  
NYSE: CCJ



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## Cameco reports third quarter financial results

### Quarterly items

- **reconfirmed sales, revenue and production guidance for the year**
- **increased mineral reserves by 19% at McArthur River**
- **signed an MOA with our joint venture partner at Inkai**
- **received funding commitment from the Saskatchewan government to construct a highway connecting McArthur River and Cigar Lake**

### Long-term growth plan

- **strong long-term industry fundamentals – 64 reactors under construction**
- **ongoing market uncertainties reduce uranium demand forecast to 2021**
- **our growth plan adjusted to focus primarily on our brownfield projects resulting in annual supply of 36 million pounds by 2018**
- **maintain our world class portfolio of projects, providing the ability to respond to positive market signals**

### Saskatoon, Saskatchewan, Canada, October 31, 2012 . . . . .

Cameco (TSX: CCO; NYSE: CCJ) today reported its consolidated financial and operating results for the third quarter ended September 30, 2012 in accordance with International Financial Reporting Standards (IFRS).

“Our results this quarter reflect the delivery pattern we reported in our second quarter report and we still expect to deliver on our sales, revenue and production guidance for the year,” said Tim Gitzel, president and CEO.

“Longer term, we continue to see strong fundamentals. However, ongoing market uncertainty in the near term led us to review and adjust our growth plans this quarter. We decided to focus on advancing projects with the greatest certainty in the near term, from which we expect to achieve about 36 million pounds of annual supply by 2018 compared to the 40 million previously targeted. We will also continue with the rest of our projects in a measured manner in order to preserve the option to bring them on as quickly as possible, if profitable.

“By taking these actions, we expect to spread our capital spending over a longer period and decrease project-related expenses. Our focus will be on execution and reducing costs without compromising on our values.

“With this adjustment, we believe we are positioned to continue to succeed in the current market environment, add value for our shareholders, and take advantage of the growth in uranium demand we see long term.”

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 7)	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 pages 7) 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 8 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 pages 7). 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 8 for more detailed discussion.

## 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.

## 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.

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#### **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 17.

## 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 8 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.

<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).

## 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.

## 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)%
Average realized price (\$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 *Operations and development project updates* starting on page 12 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 *Operations and development project updates* starting on page 12 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	(6.7)	(26.3)	(75)%	(64.3)	(62.3)	3%
Standby charges	(8.0)	(5.2)	54%	(20.9)	(16.0)	31%
Other selling costs	(0.6)	(0.6)	-	(2.9)	(6.7)	(57)%
Change in inventories	125.4	17.7	608%	160.9	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	25.7	34.3	(25)%	89.5	79.1	13%
Change in inventories	19.9	7.0	184%	33.7	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)	9.9	8.4	18%	23.8	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%

Please see our third quarter MD&A for updates to our uranium price sensitivity analysis.

## 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 results**

#### **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.

## Operations and development project updates

### Uranium – production overview

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>

#### McArthur River/Key Lake

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.

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 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 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.

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

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.

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 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.

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

## **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.

## **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**

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 document 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

## Caution about forward-looking information

This document 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 document as *forward-looking information*.

Key things to understand about the forward-looking information in this document:

- 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 below).
- 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 18, 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* below. We recommend you also review our annual information form and our annual and first, second and third 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 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 expectations regarding delivery patterns for our uranium and fuel service products
- 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 expectation regarding production in our fuel services segment for 2012
- our McArthur River mineral reserve and resource estimates
- our forecast 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 fulfill 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

### 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 in our third quarter MD&A
- 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

### Conference call

We invite you to join our third quarter conference call on Thursday, November 1, 2012 at 1:00 p.m. Eastern.

The call will be open to all investors and the media. To join the call, please dial (866) 226-1792 (Canada and US) or (416) 340-2216. An operator will put your call through. A live audio feed of the conference call will be available from a link at [cameco.com](http://cameco.com). See the link on our home page on the day of the call.

A recorded version of the proceedings will be available:

- on our website, [cameco.com](http://cameco.com), shortly after the call
- on post view until midnight, Eastern, December 1, 2012 by calling (800) 408-3053 or (905) 694-9451 (Passcode 3926907)

**Additional information**

You can find a copy of our third quarter MD&A and interim financial statements on our website at [cameco.com](http://cameco.com), on SEDAR at [sedar.com](http://sedar.com) and on EDGAR at [sec.gov/edgar.shtml](http://sec.gov/edgar.shtml).

Additional information, including our 2011 annual management's discussion and analysis, annual audited financial statements and annual information form, is available on SEDAR at [sedar.com](http://sedar.com), on EDGAR at [sec.gov/edgar.shtml](http://sec.gov/edgar.shtml) and on our website at [cameco.com](http://cameco.com).

**Profile**

We are one of the world's largest uranium producers, a significant supplier of conversion services and one of two Candu fuel manufacturers in Canada. Our competitive position is based on our controlling ownership of the world's largest high-grade reserves and low-cost operations. Our uranium products are used to generate clean electricity in nuclear power plants around the world, including Ontario where we are a limited partner in North America's largest nuclear electricity generating facility. We also explore for uranium in the Americas, Australia and Asia. Our shares trade on the Toronto and New York stock exchanges. Our head office is in Saskatoon, Saskatchewan.

As used in this news release, the terms *we*, *us*, *our* and *Cameco* mean Cameco Corporation and its subsidiaries and affiliates unless stated otherwise.

- End -

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