



PRESS RELEASE

(TSX Stock Symbol - CLT)

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Calgary, Alberta

**CELTIC REPORTS RECORD PRODUCTION OF 15,307 BOE PER DAY
IN THE THIRD QUARTER OF 2009, WITH ADDITIONAL VOLUMES BEHIND PIPE**

Celtic Exploration Ltd. ("Celtic" or the "Company") has released its financial and operating results for the three and nine months ended September 30, 2009. Summary of results are as follows:

	Three months ended September 30,			Nine months ended September 30,		
<i>(\$ thousands, unless otherwise indicated)</i>	2009	2008	Change	2009	2008	Change
FINANCIAL						
Revenue, before royalties and financial instruments	40,365	73,904	-45%	112,467	211,495	-47%
Funds from operations	27,874	34,227	-19%	76,022	99,312	-23%
Basic <i>(\$/share)</i>	0.63	0.83	-24%	1.77	2.50	-29%
Diluted <i>(\$/share)</i>	0.62	0.83	-25%	1.76	2.47	-29%
Net earnings (loss)	(13,667)	31,145	-	(24,165)	14,654	-
Basic <i>(\$/share)</i>	(0.31)	0.76	-	(0.56)	0.37	-
Diluted <i>(\$/share)</i>	(0.31)	0.75	-	(0.56)	0.36	-
Capital expenditures, net of dispositions and drilling credits	29,041	40,359	-28%	107,242	140,703	-24%
Total assets				657,919	594,672	11%
Bank debt, net of working capital				159,319	146,211	9%
Bank debt, net of working capital, excluding non-cash financial instruments				167,279	149,588	12%
Shareholders' equity				384,690	336,612	14%
Weighted average common shares outstanding <i>(thousands)</i>						
Basic	44,278	41,107	8%	43,034	39,657	9%
Diluted	44,654	41,435	8%	43,260	40,157	8%
OPERATIONS						
Production						
Oil <i>(bbls/d)</i>	3,813	3,386	13%	3,452	3,354	3%
Gas <i>(mcf/d)</i>	68,964	49,310	40%	58,205	44,311	31%
Combined <i>(BOE/d)</i>	15,307	11,604	32%	13,153	10,739	22%
Production per million shares <i>(BOE/d)</i>	346	282	23%	306	271	13%
Realized sales prices, after financial instruments						
Oil <i>(\$/bbl)</i>	79.71	90.28	-12%	81.35	87.36	-7%
Gas <i>(\$/mcf)</i>	3.39	8.28	-59%	4.13	8.77	-53%
Operating netbacks <i>(\$/BOE)</i>						
Oil and gas revenue, before hedging	28.67	69.21	-59%	31.33	71.89	-56%
Realized gain (loss) on financial instruments	6.44	(7.70)		8.32	(8.43)	
Realized sales price, after hedging	35.11	61.51	-43%	39.65	63.46	-38%
Royalties	(2.60)	(16.03)	-84%	(4.97)	(16.20)	-69%
Production expense	(9.54)	(10.87)	-12%	(10.48)	(10.31)	2%
Transportation expense	(1.03)	(0.41)	151%	(0.72)	(0.56)	29%
Operating netback	21.94	34.20	-36%	23.48	36.39	-35%
Drilling activity						
Total wells	14	15	-7%	38	40	-5%
Working interest wells	11.8	10.0	18%	33.4	30.9	8%
Success rate on working interest wells	93%	91%	2%	89%	88%	1%
Undeveloped land <i>(acres)</i>						
Gross				343,890	312,132	10%
Net				273,713	243,563	12%

Highlights - Third Quarter 2009

The three months ended September 30, 2009 was another successful quarter in the execution of the Company's growth strategy. Highlights for the third quarter of 2009 are as follows:

- Drilled 14 (11.8 net working interest) natural gas wells during the quarter resulting in an overall success rate of 93%;
- Increased average daily production by 32% to 15,307 BOE per day, up from 11,604 BOE per day in the third quarter of 2008;
- Received an average price of \$28.67 (\$35.11 after hedging) per BOE, down 59% from \$69.21 (\$61.51 after hedging) per BOE in the third quarter of 2008 and recorded an operating netback of \$21.94 per BOE, down 36% from \$34.20 per BOE in the corresponding quarter of 2008; and
- Generated \$27.9 million in funds from operations for the three month period ended September 30, 2009, down 19% from \$34.2 million in the same quarter of the previous year. Reported funds from operations per share, diluted, of \$0.62, a decrease of 25% from \$0.83 per share in the third quarter of the previous year.

Message to Shareholders

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders the Company's activities in the third quarter of 2009. During the quarter, Celtic drilled 14 (11.8 net) wells with an overall success rate of 93%. Celtic achieved record production levels during the third quarter of 2009. Production during the quarter averaged 15,307 BOE per day, an increase of 32% from 11,604 BOE per day in the third quarter of 2008. In the third quarter of 2009, Celtic recorded funds from operations of \$27.9 million (\$0.62 per share, diluted), compared to \$34.2 million (\$0.83 per share, diluted) reported in the same quarter of the previous year. Lower funds from operations in 2009 were primarily due to significantly lower realized natural gas prices compared to the previous year.

All of Celtic's drilling activity during the third quarter of 2009 took place in the Greater Kaybob area of West Central Alberta, where 14 (11.8 net) wells were drilled with an overall success rate of 93%. Of the 14 wells drilled, 12 were horizontals with multi-fracture completions and two were verticals.

At Kaybob South, Celtic drilled five horizontal wells targeting the Triassic Montney formation. All five (100% interest) wells were successfully completed with 11-stage fractures and tested during the quarter. Initially, all five wells were shut-in after testing was complete due to low spot natural gas prices at the time. Subsequently, one well has been put on production in October 2009 and the remaining four wells are expected to be put on production in November 2009.

At KayFox, Celtic drilled four wells during the third quarter, three horizontals and one vertical. Two (100% interest) wells were completed in the Triassic Montney formation, one using a 16-stage fracture and the other using an 11-stage fracture. One well has been put on production and the other is expected to be put on production in November 2009. A vertical well (100% working interest) was drilled targeting the Cretaceous Gething formation which was successfully completed and will be put on production prior to year-end. Celtic's first horizontal well (100% interest) in the Cretaceous Notikewin formation was drilled and recently completed using a 16-stage fracture. The well produced raw natural gas at an average rate of 3.5 MMCF per day during a three day test. The Company is pleased with the test results and expects to put the well on production in the fourth quarter.

At Lower Kaybob South, Celtic drilled four horizontal wells. One well (75% interest) was successfully completed in the Triassic Montney formation using an 11-stage fracture. This well has been tested and is expected to be put on production in November 2009. Two (0.76 net) wells were drilled and completed in the Cretaceous Bluesky formation, both using an 11-stage fracture. These wells have recently been put on production. The Company drilled an unsuccessful well (77% interest) targeting the Jurassic Nordegg formation.

At Pine Creek, Celtic drilled a vertical well (53% interest) targeting the Jurassic Nordegg and Triassic Montney formations. This well is expected to be completed in early November 2009.

Celtic is very pleased with its third quarter drilling results and expects to have an active fourth quarter with plans to drill another 12 to 15 wells at Kaybob, continuing development of its resource program in the Triassic Montney and Cretaceous Bluesky and Notikewin prospects. The Company is forecasting production during the fourth quarter to average between 16,000 and 16,700 BOE per day.

Celtic continues to generate new ideas for continued growth and has been actively acquiring new lands. At September 30, 2009, the Company's undeveloped land holdings in all areas increased to 343,890 (273,713 net) acres, up from 312,132 (243,563 net) acres at September 30, 2008. With this inventory of land and with plans to continue developing its Kaybob prospects, Celtic continues to generate an inventory of numerous drilling locations that will provide continued growth over the next few years.

Celtic has maintained its planned 2009 capital expenditure budget of \$150.0 million that it established back in November 2008. While many of the Company's peers have reduced their capital spending plans as a result of lower commodity prices, Celtic has been able to maintain its capital spending plans primarily due to strong drilling results, supported by a strong hedge book and the positive impact of Alberta's royalty incentives.

Oil and gas producers, like Celtic, are continually exposed to fluctuations in commodity prices that are beyond the control of the companies that produce hydrocarbons. In order to mitigate this risk and provide certainty to a portion of its cash flow supporting its capital investment program, Celtic employs an active risk management program. For the nine months ended September 30, 2009, the Company realized \$28.1 million in gains from all of its financial instrument contracts. The mark-to-market value of remaining financial instrument contracts as at September 30, 2009 were valued at \$11.2 million, before the effect of income taxes.

The royalty incentive programs introduced by the Alberta Government in 2009 will benefit the Company significantly until expiry on March 31, 2011. The Drilling Royalty Credit ("DRC") provides companies with a \$200 per metre credit on new wells drilled that may be applied against corporate crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% of corporate crown royalties for Celtic. Since April 1, 2009, Celtic has earned \$14.3 million of credits from its drilling activity. At September 30, 2009, \$4.4 million has been claimed against corporate crown royalties and \$9.9 million remains available to be claimed against future crown royalties payable.

The New Well Royalty Reduction ("NWRR") was also announced in the first half of 2009 and provides for a flat 5% royalty on new wells brought on production after March 31, 2009. This program applies to all new wells brought on production prior to April 1, 2011. The 5% royalty remains in effect for twelve producing months or for the first 500,000 MCF equivalent of gas (or 50,000 barrels of oil equivalent) produced, whichever comes first. Celtic's horizontal wells at Kaybob will benefit significantly from this program since the flat 5% royalty will replace first year royalty rates which are normally high during the first year as a result of high flush production rates.

Production

Oil and gas production in the third quarter of 2009 increased 32% to average 15,307 BOE per day compared to 11,604 BOE per day in the same quarter of 2008. Production per million shares outstanding for the three months ended September 30, 2009 averaged 346 BOE per day, up 23% from 282 BOE per day in the corresponding quarter of the previous year.

Oil and gas production for the nine months ended September 30, 2009 increased 22% to average 13,153 BOE per day compared to 10,739 BOE per day in the corresponding period of 2008. Production per million shares outstanding for the nine months ended September 30, 2009 averaged 306 BOE per day, up 13% from 271 BOE per day in the corresponding period of the previous year.

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller and Michichi and its

primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont/Figure Lake. In Northern Alberta, the Company produces light oil primarily from Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob and Swan Hills. West Central Alberta was the Company's most active drilling area in the first nine months of 2009.

Revenue

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the three months ended September 30, 2009, was \$40.4 million, a decrease of 45% compared to \$73.9 million in the same quarter of the previous year. Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the nine months ended September 30, 2009, was \$112.5 million, a decrease of 47% compared to \$211.5 million in the same period of the previous year.

Lower revenue in 2009 was due to significantly lower natural gas prices that more than offset increased production levels.

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the three months ended September 30, 2009 was \$35.11 per BOE, a decrease of 43% compared to the corresponding three month period of the previous year. The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the nine months ended September 30, 2009 was \$39.65 per BOE, a decrease of 38% compared to the corresponding nine month period of the previous year.

Oil Operations

Oil production for the third quarter ended September 30, 2009 averaged 3,813 barrels per day, an increase of 13% compared to the same quarter of the previous year. Oil production for the nine months ended September 30, 2009 averaged 3,452 barrels per day, an increase of 3% compared to the same period of the previous year.

The average price received for oil sales, after realized financial instruments, for the third quarter ended September 30, 2009 was \$79.71 (\$58.70 before financial instruments) per barrel, down 12% from the average price of \$90.28 (\$110.22 before financial instruments) per barrel received in the third quarter of 2008. The average price received for oil sales, after realized financial instruments, for the nine months ended September 30, 2009 was \$81.35 (\$53.03 before financial instruments) per barrel, down 7% from the average price of \$87.36 (\$103.88 before financial instruments) per barrel received in the first nine months of 2008.

For the quarter ended September 30, 2009, average oil royalties were 11.4% of revenue, after realized financial instruments (15.4% of revenue, before financial instruments). In the third quarter of the previous year, average oil royalties were 31.4% of revenue, after financial instruments (25.7% of revenue, before financial instruments). For the nine months ended September 30, 2009, average oil royalties were 14.2% of revenue, after realized financial instruments (21.7% of revenue, before financial instruments). In the first nine months of the previous year, average oil royalties were 30.1% of revenue, after financial instruments (25.3% of revenue, before financial instruments).

Lower oil royalty rates in 2009, before financial instruments, reflect the lower rates calculated with lower oil selling prices.

Transportation expenses for oil production in the third quarter of 2009 averaged \$0.18 per barrel compared to \$0.50 per barrel in the third quarter of 2008. Transportation expenses for oil production during the nine month period ended September 30, 2009 averaged \$0.29 per barrel compared to \$0.57 per barrel in the corresponding period of 2008.

Lower per unit transportation expenses in 2009 reflect the larger portion of newer NGL production from Kaybob which is mostly pipeline connected and therefore less expensive to transport compared to trucking oil.

For the third quarter ended September 30, 2009, oil production expenses were \$12.60 per barrel. In the same quarter of the previous year, oil production expenses were \$15.06 per barrel. For the nine months ended September 30, 2009, oil production expenses were \$13.42 per barrel. In the same period of the previous year, oil production expenses were \$14.05 per barrel.

Lower per unit production expenses in 2009 reflect the larger portion of newer NGL production from Kaybob which is less expensive to produce compared to the Company's older oil production.

Gas Operations

Gas production for the third quarter ended September 30, 2009 averaged 68,964 MCF per day, an increase of 40% compared to the corresponding quarter of the previous year. Gas production for the nine months ended September 30, 2009 averaged 58,205 MCF per day, an increase of 31% compared to the corresponding period of the previous year.

Increases in gas production in 2009 were primarily a result of Celtic's successful drilling results in its resource development prospect located in the Greater Kaybob area of Alberta.

The average price received for gas sales, after realized financial instruments, for the third quarter ended September 30, 2009 was \$3.39 (\$3.12 before financial instruments) per MCF, down 59% from the average price of \$8.28 (\$8.72 before financial instruments) per MCF received in the third quarter of 2008. The average price received for gas sales, after realized financial instruments, for the nine months ended September 30, 2009 was \$4.13 (\$3.93 before financial instruments) per MCF, down 53% from the average price of \$8.77 (\$9.56 before financial instruments) per MCF received in the first nine months of 2008.

For the quarter ended September 30, 2009, average gas royalties were 2.4% of revenue, after financial instruments (2.6% of revenue, before financial instruments). In the third quarter of the previous year, average gas royalties were 22.1% of revenue, after financial instruments (21.3% of sales, before financial instruments). For the nine month period ended September 30, 2009, average gas royalties were 10.7% of revenue, after financial instruments (11.2% of revenue, before financial instruments). In the first nine months of the previous year, average gas royalties were 22.1% of revenue, after financial instruments (20.5% of revenue, before financial instruments).

Lower gas royalty rates in 2009, before financial instruments, are a result of lower natural gas selling prices, longer depth horizontal wells which receive favourable treatment under the Alberta royalty framework and new production qualifying for reduced royalty rates under the NWRP program. In addition, royalties are reduced further as the Company continues to receive gas cost allowance ("GCA") credits which do not fluctuate with gas prices.

Transportation expenses for the third quarter ended September 30, 2009 were \$0.22 per MCF, up from \$0.06 per MCF for the same quarter in the previous year. Transportation expenses for the nine months ended September 30, 2009 were \$0.14 per MCF, an increase of 56% compared to \$0.09 per MCF for the corresponding period in the previous year.

Higher transportation expenses in 2009 reflect the higher cost to transport the Company's sulphur production, primarily from Celtic's interests in the Devonian units at Kaybob, Alberta.

For the third quarter ended September 30, 2009, production expenses of \$1.42 per MCF were 7% lower than \$1.52 per MCF in the corresponding quarter of the previous year. For the nine months ended September 30, 2009, production expenses of \$1.57 per MCF were 10% higher than \$1.43 per MCF in the corresponding period of the previous year.

Higher production expenses in 2009 reflect certain one time expenses that were incurred at Kaybob as a result of turnaround operations at the KA Gas Plant where the majority of Celtic's gas is processed.

Other Expenses

For the quarter ended September 30, 2009, general and administrative expenses were \$1.0 million (\$0.73 per BOE), interest expense was \$1.3 million, and depletion, depreciation and accretion expenses were \$27.8 million (\$19.72 per BOE). In the previous year, for the quarter ended September 30, 2008, general and administrative expenses were \$0.9 million (\$0.80 per BOE), interest expense was \$1.4 million, and depletion, depreciation and accretion expenses were \$21.8 million (\$21.18 per BOE).

For the nine month period ended September 30, 2009, general and administrative expenses were \$2.9 million (\$0.81 per BOE), interest expense was \$3.6 million, and depletion, depreciation and accretion expenses were \$72.3 million (\$20.15 per BOE). In the previous year, for the nine months ended September 30, 2008, general and administrative expenses were \$2.9 million (\$0.99 per BOE), interest expense was \$4.8 million, and depletion, depreciation and accretion expenses were \$62.3 million (\$21.18 per BOE).

Aggregate general and administrative expenses in 2009 were unchanged as the Company has retained similar staffing levels at head office, despite the growth in production year over year, resulting in a lower per BOE expense in 2009. Lower interest expense in 2009 reflects lower market interest rates which more than offset higher bank spreads. Higher depletion, depreciation and accretion expenses reflect higher production volumes; however, per unit costs are lower in 2009 as a result of proved reserve additions at lower than historic costs.

Taxes

For the quarter ended September 30, 2009, Celtic provided for a recovery of future income taxes in the amount of \$5.3 million, compared to a provision of \$13.4 million in the third quarter of 2008. For the nine month period ended September 30, 2009, Celtic provided for a recovery of future income taxes in the amount of \$9.2 million, compared to a provision of \$6.8 million in the first nine months of 2008.

For the nine months ended September 30, 2009, Celtic is not required to pay current income taxes as it has sufficient income tax deductions available to shelter taxable income for the period. Estimated income tax deductions available at September 30, 2009 are \$411.7 million and are comprised of \$96.5 million of COGPE, \$167.3 million of CDE, \$35.9 million of CEE, \$106.9 million of UCC and \$5.1 million of share issue costs.

Earnings

Net loss for the quarter ended September 30, 2009 was \$13.7 million (\$0.31 per share, basic and diluted). During the same period, funds from operations were \$27.9 million (\$0.63 per share, basic and \$0.62 per share diluted). On a barrel of oil equivalent basis, funds from operations in the third quarter of 2009 were \$19.80 per BOE, down 38% from \$32.05 per BOE in the same quarter of 2008.

Net loss for the nine months ended September 30, 2009 was \$24.2 million (\$0.56 per share, basic and diluted). During the same period, funds from operations were \$76.0 million (\$1.77 per share, basic and \$1.76 per share, diluted). On a barrel of oil equivalent basis, funds from operations in the first nine months of 2009 were \$21.19 per BOE, down 37% from \$33.77 per BOE in the same period of 2008.

The main reason for the decrease in funds from operations per BOE in 2009 was the significantly lower realized natural gas prices received by the Company.

Capital Expenditures

During the quarter ended September 30, 2009, Celtic spent \$29.0 million on capital projects. Drilling and completion operations accounted for \$18.0 million (\$32.3 million before drilling royalty credits), equipment and facility expenditures were \$7.3 million and \$1.5 million was spent on land and seismic. Proceeds from property dispositions were \$0.1 million and \$2.3 million was spent on property acquisitions. In the third quarter of the previous year, capital expenditures were \$40.4 million.

During the nine month period ended September 30, 2009, Celtic spent \$107.2 million on capital projects. Drilling and completion operations accounted for \$78.0 million (\$92.3 million before drilling royalty credits), equipment and facility expenditures were \$22.8 million and \$4.5 million was spent on land and seismic. Proceeds from property dispositions were \$0.4 million and \$2.3 million was spent on property acquisitions. In the corresponding period of the previous year, capital expenditures were \$140.7 million.

At September 30, 2009, the Company had 343,890 (273,713 net) acres of undeveloped land. The Company continues to build on its inventory of prospects for future drilling.

Drilling Activity

During the third quarter of 2009, the Company drilled 14 (11.8 net) wells resulting in 13 (11.0 net) natural gas wells, for an overall success rate of 93%. During the third quarter ended September 30, 2008, Celtic drilled 15 (10.0 net) wells, with an overall success rate of 91%. The average measured depth of net wells drilled in the third quarter of 2009 was 3,512 metres, an increase of 21% compared to the average drilling measured depth of 2,898 metres in the third quarter of 2008.

During the first nine months of 2009, the Company drilled 38 (33.4 net) wells resulting in 34 (29.7 net) natural gas wells, for an overall success rate, based on net wells, of 89%. During the nine months ended September 30, 2008, Celtic drilled 40 (30.9 net) wells, with an overall success rate of 88%. The average measured depth of net wells drilled in the first nine months of 2009 was 3,187 metres, an increase of 12% compared to the average drilling measured depth of 2,845 metres in the first nine months of 2008.

Source of Funds

Investment funding for capital expenditures incurred in the third quarter of 2009 was primarily by cash provided by operating activities.

The Company has a syndicated bank credit facility in the amount of \$215.0 million. At September 30, 2009, Celtic had drawn \$153.4 million or 71% of its authorized borrowing amount, leaving sufficient unused credit lines available to fund on-going capital expenditures and working capital deficiencies. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The credit facility matures on June 29, 2010 and may be extended for an additional 364 days.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Working Capital

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At September 30, 2009, the working capital amount, excluding non-cash financial instruments, plus outstanding bank debt represented 78% of the Company's maximum authorized bank borrowing credit limit.

Share Information

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at September 30, 2009, there were 44.5 million common shares outstanding (as at November 4, 2009, there were 44.5 million common shares outstanding). There are no preferred shares outstanding.

As at September 30, 2009, directors, employees and certain consultants have been granted options to purchase 3.3 million common shares of the Company at an average exercise price of \$13.69 per share.

Advisory Regarding Forward-Looking Statements

Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

Current Economic Environment

Late in 2008 and early in 2009, the financial community around the world was rocked with unprecedented losses and business failures. The recovery has been slow and as a result, the current economic environment is challenging and uncertain. Celtic expects to see an improving economic environment in late 2009 and into 2010, with improving commodity prices, less volatile financial markets and better access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby cash flow for 2009 was secured to a certain extent through the use of commodity price, currency and interest rate financial derivative instruments.

Celtic's capital expenditure program remains flexible and if the current economic environment continues to deteriorate, the Company has the ability to defer expenditures into the future.

2010 Guidance

Celtic continues to remain optimistic about its future prospects. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on a historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone hydrocarbon potential.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of \$170 million for 2010. The capital budget will be increased to \$205 million if the Company obtains approval from the ERCB to build its proposed gas processing facility at Kaybob. Capital expenditures will be reduced by drilling royalty credits earned during 2010 in the amount of \$20.0 to \$25.0 million. Capital spending for 2010 is expected to be financed by funds from operations, with access to available bank credit lines and common share issuances, if necessary.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2010, estimated decline rates on existing and new volumes, Celtic expects production in 2010 to average between 18,500 and 18,700 BOE/d (23% oil and 77% gas). This represents between a 32% and 34% increase from the average production of 14,000 BOE/d forecasted for 2009. Celtic expects to exit 2010 with production in excess of 20,000 BOE/d.

Financial turmoil and the global recession which have been in the headlines for some time may now be starting to stabilize with expectations of a global economic recovery in 2010. As a result, Celtic expects oil prices to be higher in 2010 compared to 2009. Industrial demand for natural gas in North America is also expected to increase with a recovering economy, while at the same time, natural gas supply in the United States may shrink given the lower number of rigs actively drilling for natural gas compared to a year ago. Both these factors will likely result in higher natural gas prices in 2010 compared to 2009. The one variable that remains is the amount of natural gas demand due to heating that will result from the weather this winter.

The Company's average commodity price assumptions for 2010 are US\$70.00 per barrel for WTI oil, US\$6.95 per MMBTU for NYMEX natural gas, \$6.00 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.970. These prices compare to forecasted 2009 average prices of US\$59.00 per barrel for WTI oil, US\$4.20 per MMBTU for NYMEX natural gas, \$3.75 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.868.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined under Future Commitments above), funds from operations for 2010 is forecasted to be approximately \$190.0 million or \$4.27 per share (\$4.19 per share, diluted) and net earnings are forecasted to be approximately \$33.2 million or \$0.75 per share (\$0.73 per share, diluted).

Changes in forecasted commodity prices and variances in production estimates can have a significant impact to estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements shown above.

Bank debt, net of working capital, is estimated to be \$125.0 million by the end of 2010 or approximately 0.7 times forecasted 2010 funds from operations. If the gas processing facility at Kaybob is approved for construction in 2010, bank debt, net of working capital would increase to \$160.0 million or approximately 0.8 times forecasted 2010 funds from operations.

Celtic's capital expenditure budget for 2010 will see the Company participate at high working interests in the drilling of approximately 50 to 55 wells during the year, of which approximately 85% will be horizontal wells. Celtic continues to evaluate and pursue potential property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company's planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, reserves, net asset value and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2010 and beyond.

The information set out herein under the heading "2010 Guidance" is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2009 and 2010. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Non-GAAP Financial Measurements

This document contains the terms "funds from operations", "operating netback" and "production per share" which do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Operating netbacks are determined by deducting royalties, production expenses and transportation expenses from oil and gas revenue. Funds from operations are determined by adding back settlement of asset retirement obligations and change in non-cash operating working capital to cash provided by operating activities. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

Other Measurements

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil

equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids (“NGLs”). NGLs include condensate, propane, butane and ethane. References to gas in this discussion include natural gas and sulphur.

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