



PRESS RELEASE

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CELTIC REPORTS FINANCIAL RESULTS FOR THE YEAR ENDED DECEMBER 31, 2009

Celtic Exploration Ltd. (“Celtic” or the “Company”) has released its operating results for the three months and twelve months ended December 31, 2009. Summary of results are as follows:

(\$000's, unless otherwise specified)	Three months ended December 31,			Twelve months ended December 31,		
	2009	2008	Change	2009	2008	Change
Revenue, before royalties and financial instruments	60,146	51,842	16%	172,613	263,337	-34%
Funds from operations	42,003	32,049	31%	118,025	131,360	-10%
Basic (\$/share)	0.94	0.78	21%	2.72	3.28	-17%
Diluted (\$/share)	0.93	0.78	19%	2.70	3.27	-17%
Net earnings (loss)	906	29,585	-97%	(23,258)	44,239	-
Basic (\$/share)	0.02	0.72	-97%	(0.54)	1.10	-
Diluted (\$/share)	0.02	0.72	-97%	(0.54)	1.10	-
Capital expenditures, net of dispositions and drilling credits	41,519	42,774	-3%	148,761	183,477	-19%
Total assets				678,770	649,654	4%
Bank debt, net of working capital				168,417	136,595	23%
Bank debt, net of working capital, excluding non-cash financial instruments				168,209	160,187	5%
Shareholder's equity				387,190	367,808	5%
Common shares outstanding (thousands)				44,563	41,307	8%
Stock options outstanding (thousands)				3,308	3,229	2%
Weighted average common shares						
Basic (thousands)	44,540	41,207	8%	43,414	40,047	8%
Diluted (thousands)	45,332	41,264	10%	43,750	40,141	9%

Celtic previously released its operating results for the three months and twelve months ended December 31, 2009. These results are summarized in the table below:

	Three months ended December 31,			Twelve months ended December 31,		
	2009	2008	Change	2009	2008	Change
Production						
Oil [BBLs/d]	4,384	3,554	23%	3,687	3,404	8%
Gas [MCF/D]	77,339	51,029	52%	63,028	46,000	37%
Combined [BOE/D]	17,274	12,059	43%	14,192	11,071	28%
Production per million shares [BOE/D]	388	293	32%	327	276	18%
Drilling activity						
Total wells	17	14	21%	55	54	2%
Working interest wells	9.6	10.2	-6%	43.0	41.1	5%
Success rate on working interest wells	100%	100%		91%	88%	3%
Undeveloped land						
Gross acres				363,473	318,969	14%
Net acres				294,700	246,629	19%
Reserves						
Oil & NGLs [MBBLs]				15,042	14,372	5%
Natural gas [MMCF]				272,236	232,831	16%
Combined [MBOE]				60,415	53,177	13%
Finding, development & acquisition cost						
Proved [\$ /BOE]				\$12.89	\$19.43	-34%
Proved plus Probable [\$ /BOE]				\$9.84	\$12.24	-20%
Recycle ratio [P+P]				2.5 x	2.9 x	-14%
Net asset value per share						
NPV 10%, before tax				\$19.76	\$18.97	4%

President's Message

Celtic is pleased to report to shareholders on the Company's activities. Once again, Celtic achieved superior operating results in 2009, notwithstanding a significant downturn in the Canadian and global economies. The Company reported record production and reserves for the year and at the same time retained financial flexibility by maintaining a strong balance sheet.

Highlights of 2009 results include funds from operations of \$118.0 million (\$2.70 per share, diluted), net capital expenditures of \$148.8 million, record production of 14,192 BOE per day, increased reserves of 60.4 million BOE, lower finding and development costs of \$9.84 per BOE for proved plus probable reserves and a prudent financial position with debt, net of working capital, of \$168.4 million or 1.0 times annualized fourth quarter 2009 funds from operations.

With its strong hedge position and with Alberta's new royalty incentive programs that took effect on April 1, 2009, Celtic embarked on an active drilling program commencing on April 1, 2009. The incentive programs which are in place until March 31, 2011, provide the Company with lower royalty rates and drilling royalty credits. Ultimately, the royalty reduction and drilling credits combined will result in savings to the Company in excess of half of total drilling expenditures.

The Company continued to expand its development potential in the Triassic Montney play in Celtic's most active operating area, Kaybob, Alberta. In addition, the Company also began drilling Cretaceous Bluesky and Notikewin prospects at Kaybob with encouraging results.

Celtic efficiently allocated the majority of its 2009 capital program to its Kaybob Montney, Bluesky and Notikewin development prospects. As a result, the Company has positioned itself to reap substantial rewards from drilling repeatable high productivity horizontal wells with multi-fracture completion technology allowing it to develop its large hydrocarbon resources in an economic manner.

Celtic employs horizontal drilling with multi-stage fracture completion techniques with high rates of success at Kaybob. Initially, horizontal wells were drilled and completed using a five-stage fracture configuration. With success, the Company began using a seven-stage fracture configuration. Most recently, Celtic has employed eleven to sixteen-stage fractures with positive results. As a result of the Company's recent success with eleven to sixteen-stage fracture completions, Celtic expects to realize significant gains in productivity and higher recovery rates of gas-in-place, with a smaller percentage increase in capital spending. Ultimately, the Company expects these newer horizontal wells to recover more reserves at a lower per unit cost.

To date at Kaybob, the highest average initial raw natural gas production rate for a well completed in the Triassic Montney formation has been 16.6 mmcf per day and for a well completed in the Cretaceous Bluesky formation, the highest initial production rate has been 15.1 mmcf per day.

The economics of developing these natural gas reservoirs at Kaybob are further enhanced by associated recoverable liquids. The average liquids content in the Montney at Kaybob is approximately 26 bbls (40% NGLs and 60% condensate) per mmcf of raw gas and in the Bluesky, it is approximately 40 bbls (85% NGLs and 15% condensate) per mmcf of raw gas.

In addition to the Triassic and Cretaceous formations, Celtic has a large undeveloped land position in the Devonian Duvernay shale. This formation has attracted significant interest in recent months as is evidenced by the substantial amounts of capital that were incurred by other companies at recent Alberta crown land sales accumulating Duvernay rights in close proximity to Kaybob. Celtic expects to drill an exploration well targeting the Duvernay shale in 2010.

The following table outlines the Company's land position as at December 31, 2009 in the Greater Kaybob area:

KAYBOB LAND HOLDINGS					
	Montney Rights	Bluesky Rights	Notikewin Rights	Nordegg Rights	Duvernay Rights
Gross acres	102,720	37,280	34,240	102,080	93,920
Net acres	89,874	22,995	22,011	88,226	87,476
Average working interest	87%	62%	64%	86%	93%

Celtic also has the following unit interests in the Greater Kaybob area: Kaybob South Unit # 1 – 9.3% unit interest in 40 sections of unitized rights in the Beaverhill Lake; Kaybob South Unit # 2 – 61.4% unit interest in 26 sections of unitized rights in the Beaverhill Lake; and Kaybob South Unit # 3 – 10.2% unit interest in 50.25 sections of unitized rights in the Beaverhill Lake.

In the greater Kaybob area where the Company has been actively pursuing Montney, Bluesky and Notikewin prospects, Celtic also has opportunities in other formations including the Jurassic Nordegg and Devonian Beaverhill Lake and intends to commence a program in the Devonian Duvernay.

In the Company's December 31, 2009 reserve evaluation, Sproule Associates Limited ("Sproule") has assigned reserves to 33.6 net un-drilled wells in the Montney formation, 3.7 net un-drilled wells in the Bluesky formation, 1.6 net un-drilled wells in the Notikewin formation, 2.0 net un-drilled wells in the Nordegg formation and 4.1 net un-drilled wells in the Beaverhill Lake formation. Reserves were not assigned to future potential drilling in the Duvernay formation.

The following table outlines the reserves included in the December 31, 2009 reserve evaluation in the Greater Kaybob area:

KAYBOB RESERVES					
	Montney	Bluesky	Notikewin	Other Formations	Total Greater Kaybob
Proved Reserves					
Natural gas [MMCF]	99,862	13,729	1,583	26,855	142,030
NGLs [MBOE]	2,985	489	57	2,135	5,666
Combined [MBOE]	19,629	2,777	321	6,611	29,338
Net present value 10% BT [\$000's]	312,534	56,900	5,323	99,691	474,448
Number of net wells – producing	69.8	6.6	1.8	25.9	104.1
Number of net wells – un-drilled locations	20.7	2.4	0.8	3.1	27.0
Proved plus Probable Reserves					
Natural gas [MMCF]	170,407	23,923	5,706	43,597	243,632
NGLs [MBOE]	5,041	854	206	3,482	9,582
Combined [MBOE]	33,442	4,841	1,157	10,748	50,188
Net present value 10% BT [\$000's]	500,500	92,517	19,605	152,944	765,566
Number of net wells – producing	69.8	6.6	1.8	25.9	104.1
Number of net wells – un-drilled locations	33.6	3.7	1.6	6.1	45.0

Looking ahead to 2010, Celtic will use its knowledge and experience with horizontal multi-stage fracture drilling and completion technology in other areas in west central Alberta with the objective of developing new resource plays similar to the Company's Kaybob resource plays. At present, the Company has amassed 46,400 acres of undeveloped lands on several exploration plays targeting natural gas reservoirs in the Triassic Montney and Cretaceous Bluesky, Notikewin and Cardium formations, outside of Celtic's existing Kaybob operating area. The Company expects to have tested each one of these exploration plays by mid-year 2010.

In February 2010, Celtic announced that it had entered into an agreement to divest its interest in assets located at Swan Hills, Alberta. This transaction is effective February 1, 2010 and is expected to close on or about March 31, 2010. The Company expects to receive proceeds of \$53.2 million, before closing adjustments. At December 31, 2009, proved reserves assigned to these assets were 1.1 million BOE and proved plus probable reserves were 2.0 million BOE. Production from these assets at the time of announcement was approximately 500 BOE per day. As a result, the Company is selling proved reserves for \$49.40 per BOE and proved plus probable reserves for \$26.61 per BOE. Proceeds for production equates to \$106,500 per daily flowing BOE. These calculations are before deducting land values and before future capital required to develop reserves.

The Company expects to re-deploy a portion of the proceeds from this disposition towards Celtic's 2010 drilling and land acquisition program. The balance will initially be used to pay down bank debt, leaving the Company with higher unused credit lines that can be accessed as opportunities arise.

2009 Highlights

The year ended December 31, 2009 was another successful year in the execution of the Company's growth strategy. Highlights for 2009 are as follows:

- Drilled 55 (43.0 net working interest) wells during 2009 resulting in 50 (38.9 net) gas wells and 1 (0.3 net) oil well, for an overall success rate, based on net wells, of 91%;
- Increased average daily production by 28% to 14,192 BOE per day, up from 11,071 BOE per day in 2008 and achieved daily average production per million shares of 327 BOE per day, up 18% in 2009 compared to 276 BOE per day in the previous year;

- Increased proved plus probable reserves by 13% to 60.4 million BOE, up from 53.6 million BOE at December 31, 2008 and replaced 2009 production by a factor of 2.3 times;
- Reported finding, development and acquisition cost (including future development capital) of \$9.84 per BOE resulting in a recycle ratio of 2.5 times based on proved plus probable reserves;
- Reported net asset value at year-end of \$19.76 per share, based on net present value of reserves discounted at 10%, before tax and using forecasted 2010 average commodity prices of US\$79.17 per barrel for WTI oil and \$5.08 per GJ for AECO gas;
- Accumulated additional undeveloped land in new resource play prospects targeting the Triassic Montney, Cretaceous Bluesky, Cretaceous Notikewin and Devonian Duvernay formations in west central Alberta;
- Generated gross proceeds of \$36.4 million by completing an equity financing that resulted in the issuance of 2.8 million common shares at a price of \$13.25 per share; and
- Reported funds from operations per share, diluted, of \$2.70, a decrease of 17% from \$3.27 per share in the previous year.

Production

Oil and gas production in 2009 increased 28% to average 14,192 BOE per day compared to 11,071 BOE per day in 2008. Average production in the fourth quarter of 2009 was 17,274 BOE per day, up 43% from 12,059 BOE per day in the fourth quarter of 2008. Production per million shares outstanding in 2009 averaged 327 BOE per day, up 18% from 276 BOE per day in 2008.

Revenue

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the year ended December 31, 2009 was \$172.6 million, a decrease of 34% compared to \$263.3 million in the previous year. For the three months ended December 31, 2009, revenue was \$60.1 million, up 16% from \$51.8 million in the fourth quarter of 2008.

Lower revenue in 2009 was primarily a result of lower commodity prices which 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 year ended December 31, 2009 was \$40.43 per BOE (\$33.33 per BOE before financial instruments), a decrease of 33% (a decrease of 49% before financial instruments) compared to the previous year. For the three months ended December 31, 2009, the average adjusted product price received was \$42.17 per BOE (\$37.85 per BOE before financial instruments), down 18% (down 19% before financial instruments) from the average price received in the fourth quarter of 2008.

Oil Operations

Oil production for the year ended December 31, 2009 averaged 3,687 bbls per day, an increase of 8% compared to the previous year. For the three months ended December 31, 2009, average oil production was 4,384 bbls per day, up 23% from the fourth quarter of 2008. Increased oil production in 2009 reflects the addition of NGLs from the increased liquids-rich natural gas production at Kaybob, Alberta.

The average price received for oil sales, after realized financial instruments, for the year ended December 31, 2009 was \$81.00 (\$56.45 before financial instruments) per barrel, down 2% (down 38% before financial instruments) from the average price of \$82.45 (\$90.48 before financial instruments) per barrel received in 2008. The Company recorded a realized gain of \$33.0 million on financial instruments relating to oil price transactions in 2009 compared to a realized loss of \$10.0 million in the previous year. The average price received for oil sales, after realized financial instruments, for the fourth quarter ended December 31, 2009 was \$80.22 (\$64.46 before financial instruments) per barrel, up 17% (up 22% before financial instruments) from the average price of \$68.63 (\$52.81 before financial instruments) per barrel received in the fourth quarter of 2008.

For the twelve months ended December 31, 2009, average oil royalties were 13.3% of revenue, after financial instruments (19.0% of revenue, before financial instruments). In the previous year, average oil royalties were 27.5% of revenue, after financial instruments (25.1% of revenue, before financial instruments). Lower royalty rates, before financial instruments, in 2009 were primarily a result of lower oil prices received, compared to the previous year. For the quarter ended December 31, 2009, average oil royalties were 11.1% of revenue, after financial instruments (13.9% of revenue, before financial instruments). In the fourth quarter of the previous year, average oil royalties were 18.5% of revenue, after financial instruments (24.0% of revenue, before financial instruments).

Transportation expenses for oil production in 2009 averaged \$0.27 per barrel compared to \$0.53 per barrel in 2008. Lower per unit transportation expenses in 2009 reflect the larger portion of newer NGL production which is mostly pipeline connected and therefore less expensive to transport compared to trucking crude oil. Transportation expenses for oil production in the fourth quarter of 2009 averaged \$0.25 per barrel compared to \$0.41 per barrel in the fourth quarter of 2008.

For the year ended December 31, 2009, production expenses were \$13.11 per barrel, an improvement from the previous year's \$13.76 per barrel. During the fourth quarter of 2009, production expenses averaged \$12.37 per barrel compared to \$12.95 per barrel in the fourth quarter of 2008. Lower per barrel production expenses in 2009 compared to the previous year are primarily a result of the larger component of NGLs included in oil production which are less costly to produce than Celtic's crude oil production.

Gas Operations

Gas production for the year ended December 31, 2009 averaged 63,028 mcf per day, an increase of 37% compared to 46,000 mcf per day in 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 at Kaybob, Alberta. Gas production for the fourth quarter ended December 31, 2009 averaged 77,339 mcf per day, an increase of 52% compared to the corresponding period of the previous year.

The average price received for gas sales, after realized financial instruments, for the year ended December 31, 2009 was \$4.36 (\$4.20 before financial instruments) per mcf, down 48% (down 53% before financial instruments) from the average price of \$8.37 (\$8.94 before financial instruments) per mcf received in 2008. The Company recorded a realized gain of \$3.7 million on financial instruments relating to gas price transactions in 2009 compared to a realized loss of \$9.6 million in the previous year. The average price received for gas sales, after realized financial instruments, for the fourth quarter ended December 31, 2009 was \$4.86 (\$4.79 before financial instruments) per mcf, down 34% (down 35% before financial instruments) from the average price of \$7.36 (\$7.36 before financial instruments) per mcf received in the fourth quarter of 2008.

For the year ended December 31, 2009, average gas royalties were 8.5% of revenue, after financial instruments (8.8% of sales, before financial instruments). In the previous year, average natural gas royalties were 21.4% of revenue, after financial instruments (20.0% of sales, before financial instruments). Actual Crown natural gas royalties payable are determined based on an Alberta reference price and not on actual corporate realized prices. For the quarter ended December 31, 2009, average natural gas royalties were 4.3% of revenue, after financial instruments (4.4% of sales, before financial instruments). In the fourth quarter of the previous year, average natural gas royalties were 19.2% of revenue, after financial instruments (19.2% of sales, before financial instruments).

The New Well Royalty Reduction ("NWRR") drilling incentive program was introduced by the Alberta government in early 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 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. Celtic's 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 NWRR 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 year ended December 31, 2009 were \$0.15 per mcf, an increase of 50% compared to \$0.10 per mcf for the previous year. Higher transportation expenses in 2009 reflect the increase in gas production that is transported on third party pipeline infrastructure. Transportation expenses for the fourth quarter ended December 31, 2009 were \$0.16 per mcf, an increase of 45% compared to \$0.11 per mcf for the same period in the previous year.

For the twelve months ended December 31, 2009, production expenses of \$1.54 per mcf were 7% higher than \$1.44 per mcf in the previous year. Higher production expenses in 2009 reflect the additional expenses incurred at Kaybob where a significant amount of the Company’s production is processed through the KA Gas Plant. This plant was down for approximately five weeks in the second quarter of 2009 for turnaround operations that occur every four years. For the fourth quarter ended December 31, 2009, production expenses were \$1.48 per mcf compared to \$1.45 per mcf in the fourth quarter of 2008.

Interest Expense

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including HSBC Bank Canada, Canadian Western Bank, Royal Bank of Canada and Fortis Capital (Canada) Ltd. The authorized borrowing amount under this facility is \$215.0 million. The facilities are available for a period of 364 days, maturing on June 29, 2010. 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. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of \$500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.5% to bank prime plus 3.5%, depending upon the Company’s then current debt to cash flow ratio of between less than one and one tenth times to greater than three times. Under the credit facility, borrowings through the use of bankers’ acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.5% to 4.5%, depending upon the Company’s then current debt to cash flow ratio of between less than one and one tenth times to greater than three times.

The Company has entered into interest rate swap transactions whereby borrowings through bankers’ acceptances in the amount of \$100.0 million maturing on April 22, 2011 has been fixed at an annual interest rate of 3.2% up to April 22, 2010 and 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees.

Interest expense for the year, before financial instruments, was \$5.0 million at an average rate of 3.3% compared to \$6.1 million at an average rate of 4.8% in 2008.

The Company recorded a realized loss of \$2.4 million on financial instruments relating to interest rate swap transactions in 2009 compared to a realized loss of \$0.2 million in the previous year.

General and Administrative Expenses

General and administrative (“G&A”) expenses for the year ended December 31, 2009 were \$3.9 million or \$0.77 per BOE compared to \$4.0 million or \$0.97 per BOE in 2008. G&A expenses are reduced by overhead recovered on Company operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized.

Celtic continues to operate with low G&A expense per BOE compared to many of its peers and is able to do so primarily due to the fact that the Company’s operations are geographically focused and concentrated with the

majority of its production coming from the greater Kaybob area of Alberta. With 39 head office employees, G&A expense per employee in 2009 averaged \$101,203 per employee. This is a 10% reduction from \$112,845 per employee in 2008.

Stock Based Compensation Expense

Stock based compensation expense is a non-cash charge which reflects the value of stock options awarded to directors, employees and certain consultants. The value is recognized as an expense over the period from the grant date to the date of vesting of the award.

For the year ended December 31, 2009, stock based compensation expense was \$2.4 million, compared to \$1.9 million in 2008.

On a barrel of oil equivalent basis, stock based compensation expense was \$0.46 per BOE in 2009, unchanged from 2008.

Provision for Non-recoverable Accounts Receivable

Celtic has expensed \$31.2 million (\$13.2 million in 2009 and \$18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately \$32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the *Companies' Creditors Arrangement Act Canada* ("CCAA") in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.

Depletion, Depreciation and Accretion

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs along with estimated future development capital expenditures to be incurred in order to develop proved reserves, are depleted on a unit of production basis using estimated proved oil and gas reserves. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit of production basis, and the provision is included in depletion, depreciation and accretion ("DD&A"). DD&A expense for the period ended December 31, 2009 was \$101.8 million or \$19.65 per BOE, compared to the previous year's amount of \$85.6 million or \$21.13 per BOE.

Taxes

In 2009, Celtic provided for a recovery of future income taxes in the amount of \$9.6 million and in 2008, Celtic recorded a provision for future income taxes in the amount of \$14.0 million. These amounts differ from the expected provision for (recovery of) income taxes based on the statutory combined income tax rate of 29.0% in 2009 and 29.5% in 2008 due to the differences between non-deductible stock based compensation expense and the recognition of a benefit primarily relating to substantively enacted changes to future federal and provincial income tax rates. An analysis of the income tax provision is included in the notes to the financial statements. At December 31, 2009, Celtic had estimated unused income tax deductions available of approximately \$412.2 million.

Funds from Operations and Cash Provided by Operating Activities

Funds from operations is a non-GAAP measure defined as cash provided by operating activities before changes in non-cash operating working capital and settlement of asset retirement obligations. Despite being a non-GAAP measure, funds from operations is commonly used in the oil and gas industry and by Celtic to assist in measuring the Company's ability to finance capital programs and meet financial obligations.

Funds from operations for the year ended December 31, 2009 was \$118.0 million (\$2.72 per share, basic and \$2.70 per share, diluted). In 2008, funds from operations were \$131.4 million (\$3.28 per share, basic and \$3.27 per share, diluted). Funds from operations for the three months ended December 31, 2009 was \$42.0 million (\$0.94 per share, basic and \$0.93 per share, diluted). In the fourth quarter of 2008, funds from operations were \$32.0 million (\$0.78 per share, basic and \$0.78 per share, diluted).

On a barrel of oil equivalent basis, funds from operations in 2009 were \$22.78 per BOE, down 30% from \$32.44 per BOE in 2008. The primary reason for the decrease in 2009 was a result of lower oil and gas prices realized during the year, which more than offset the lower aggregate expenses in 2009 compared to the previous year. On a barrel of oil equivalent basis, funds from operations in the fourth quarter of 2009 were \$26.44 per BOE, down 8% from \$28.89 per BOE in the fourth quarter of 2008.

Cash provided by operating activities for the year ended December 31, 2009 was \$103.7 million, up 16% from \$89.3 million in 2008. Cash provided by operating activities for the three months ended December 31, 2009 was \$33.9 million, up 47% from \$23.0 million in the fourth quarter of 2008.

Net Earnings

Net loss for the year ended December 31, 2009 was \$23.3 million (\$0.54 per share, basic and diluted). Net earnings for the year ended December 31, 2008 was \$44.2 million (\$1.10 per share, basic and diluted). Net earnings for the three months ended December 31, 2009 was \$0.9 million (\$0.02 per share, basic and diluted). Net earnings for the fourth quarter of 2008 were \$29.6 million (\$0.72 per share, basic and diluted).

Capital Expenditures

Celtic is committed to future growth through its strategy to augment strategic oil and gas acquisitions with exploitation upside, and at the same time, implement a full cycle exploration and development program. Since the Company began active oil and gas operations in September 2002, Celtic has completed several acquisitions in order to establish a cash flow platform and an inventory of exploration and development prospects from which the Company can grow through the drill bit. Examples of where Celtic has successfully employed its strategy to acquire an initial position in an area and subsequently expand the area making it core to the Company include Princess/Bantry, Ashmont and Fox Creek. Examples of where Celtic has successfully employed its strategy to acquire assets in existing operating areas in order to expand its inventory of developments prospects include Kaybob South, Lower Kaybob South and KayFox.

During the year ended December 31, 2009, Celtic incurred \$147.0 million on exploration and development activity, \$2.2 million on property acquisitions and recorded net proceeds of \$0.4 million from property dispositions. Drilling and completion operations accounted for \$125.3 million and the Company earned \$20.6 million in drilling royalty credits that are eligible to be claimed against corporate crown royalties payable. Equipment and facility expenditures were \$32.1 million. The balance of \$10.2 million was spent on land and seismic, building the Company's inventory of prospects for future drilling opportunities. Approximately 96% of net wells drilled were categorized as development and 4% were exploratory.

During the year ended December 31, 2008, Celtic incurred \$138.4 million on exploration and development activity, \$49.4 million on property acquisitions and recorded net proceeds of \$4.3 million from property dispositions. Drilling and completion operations accounted for \$102.8 million and equipment and facility expenditures were \$30.3 million. The balance of \$5.3 million was spent on land and seismic, building the Company's inventory of prospects for future drilling. Approximately 79% of net wells drilled were development and 21% were exploratory.

Land Holdings

As at December 31, 2009, Celtic owned 412,654 net acres of land, of which 294,700 net acres were undeveloped. In the previous year, as at December 31, 2008, Celtic owned 358,249 net acres of land, of which 246,629 net acres were undeveloped. The Company's net land holdings increased 15% in 2009 and its undeveloped land holdings increased 19% year over year. Approximately 9% of the Company's undeveloped

land position is subject to expiry in 2010, if not developed. Celtic holds an average working interest of 73% in its lands, up from an average working interest of 69% in the previous year.

In 2009 the Company took full advantage of low natural gas prices and the overall downturn in economic activity in the oil and gas industry by participating at land sales in an environment of lower costs in order to continue to build its prospect inventory.

In 2009, Celtic incurred \$8.3 million at Alberta Crown land sales acquiring 74,170 net acres of petroleum and natural gas rights at an average cost of \$112 per acre; compared to an industry average of \$163 per acre. These prices were lower than the previous year in which Celtic spent \$4.1 million acquiring 24,000 net acres at an average cost of \$171 per acre, compared to the 2008 industry average of \$186 per acre.

Since Celtic's inception in 2002, 2009 was the Company's most active year for acquiring petroleum and natural gas rights at Alberta Crown land sales. The majority of Celtic's 2009 land expenditures were directed towards expanding the Company's acreage position in formations such as the Triassic Montney, Cretaceous Bluesky and Cretaceous Notikewin with characteristics that the Company believes are similar to its existing development resource plays at Kaybob, Alberta. In addition, the Company has also assembled a significant land position in the Devonian Duvernay formation in the Greater Kaybob area of Alberta.

The Company evaluates the fair market value of its undeveloped land holdings internally. At December 31, 2009, the fair market value of Celtic's net undeveloped land was \$56.6 million or \$192 per acre up from \$48.3 million or \$196 per acre at December 31, 2008.

Looking ahead to 2010, Celtic will continue its internally generated, prospect-driven land acquisition strategy. This strategy will be complemented by third party farm-in arrangements in core exploration and development areas. Celtic's land acquisition strategy remains focused on building a significant base of high working interest operated prospects, ensuring the Company is in a position to control its capital expenditure program.

Drilling

Drilling activity in North America declined significantly in 2009 compared to the previous year as a result of lower oil and gas prices and uncertainty in credit and capital markets. However, Celtic's drilling operations remained active in 2009 as the Company's strong financial position backed by its prudent commodity price risk management strategy and the substantial benefits derived from Alberta's royalty drilling incentive programs, allowed the Company to thrive during difficult economic conditions.

During the year ended December 31, 2009, Celtic drilled 55 (43.0 net) wells, with an overall success rate of 91% on net wells drilled. The Company's average working interest in wells drilled during 2009 was 78%. The split between development drilling and exploratory drilling was 96% and 4%, respectively. In 2009, Celtic's horizontal drilling activity increased resulting in the average measured depth of net wells drilled of 3,289 metres. The Company drilled a total of 141,409 metres during the year.

In the previous year ended December 31, 2008, Celtic drilled 54 (41.1 net) wells, with an overall success rate of 88% on net wells drilled. The Company's average working interest in wells drilled during 2008 was 76%. The split between development drilling and exploratory drilling was 79% and 21%, respectively. In 2008, the average measured depth of net wells drilled was 2,960 metres.

Net Asset Value

Celtic's net asset value at December 31, 2009 increased to \$946.1 million, up 12% from \$844.7 million at December 31, 2008. On a per share basis, net asset value increased by 4% to \$19.76 per share compared to \$18.97 per share at December 31, 2008. The present value of petroleum and natural gas ("P&NG") reserves were determined by Sproule in their year-end evaluation report. The present value of P&NG reserves is determined using a discount rate of 10% before tax. Undeveloped land at December 31, 2009 was valued at an average price of \$192 per acre compared to \$196 per acre at December 31, 2008. Proceeds from exercise of

stock options are based on average exercise prices of \$13.90 per share at December 31, 2009 and \$12.96 per share at December 31, 2008.

Share Information

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2009, there were 44.6 million common shares outstanding (as at March 3, 2010, there were 44.7 million common shares outstanding). There are no preferred shares outstanding.

As at December 31, 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 \$13.90 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements.

The Company's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "CLT". During 2009, 40.4 million shares traded on the TSX at an average price of \$15.93 per share. These volumes were 14% higher than the 35.5 million shares traded in 2008 at an average price of \$13.35 per share.

Future Commitments – Financial Instruments

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2009:

Daily quantity	Remaining term of contract	Fixed price per mmbtu
50,000 mmbtu/d	January 1 to March 31, 2010	US\$ 0.64
50,000 mmbtu/d	April 1 to December 31, 2010	US\$ 0.68

The Company has entered into currency average rate forward swap transactions whereby U.S. dollars have been converted to Canadian dollars as summarized in the following table:

Amount	Remaining term of contract	Fixed exchange rate (CAD/USD)
US\$ 4,000,000/month	January 1 to December 31, 2010	1.2106

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at December 31, 2009:

Amount	Remaining term of contract	Fixed interest rate
CA\$ 80,000,000	January 1, 2010 to April 22, 2010	3.30%
CA\$ 20,000,000	January 1, 2010 to April 22, 2010	2.54%
CA\$ 100,000,000	April 22, 2010 to April 21, 2011	2.07%

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.

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 \$187.0 million for 2010. The capital budget will be increased by \$35.0 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, disposition of certain assets located at Swan Hills for proceeds of \$53.2 million, 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 (19% oil and 81% gas). This represents between a 30% and 32% increase from the average production of 14,192 BOE/d achieved in 2009. Celtic expects to exit 2010 with production in excess of 20,000 BOE/d.

Financial turmoil and the global recession which frequented news headlines in recent months 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 Company's average commodity price assumptions for 2010 are US\$72.50 per barrel for WTI oil, US\$6.50 per MMBTU for NYMEX natural gas, \$5.75 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.952. These prices compare to average 2009 prices of US\$61.63 per barrel for WTI oil, US\$4.01 per MMBTU for NYMEX natural gas, \$3.97 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.880.

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 \$170.0 million or \$3.82 per share (\$3.74 per share, diluted) and net earnings are forecasted to be approximately \$23.0 million or \$0.52 per share (\$0.51 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 \$109.2 million by the end of 2010 or approximately 0.6 times forecasted 2010 funds from operations. If the gas processing facility at Kaybob is approved and constructed in 2010, bank debt, net of working capital would increase to \$144.2 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 55 to 60 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", "production per share" and "net asset value" 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. Sulphur volumes have been converted to natural gas equivalence at one long ton per 10 thousand cubic feet.

For further information, please contact:

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Or visit our website site at www.celticex.com.

Financial Statements

Celtic's audited financial statements and related notes for the year ended December 31, 2009 will be available to the public on SEDAR at www.sedar.com and will also be posted on the Company's website at www.celticex.com prior to March 29, 2010. In the interim, the balance sheet, statement of earnings and statement of cash flows are provided below. All amounts are thousands of dollars.

Balance Sheet

	As at December 31, 2009	As at December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	42	73
Accounts receivable	49,252	50,728
Drilling royalty credits	13,158	-
Prepaid expenses and deposits	4,947	4,010
Fair value of financial instruments	1,463	36,154
Future income tax asset	510	848
Total current assets	69,372	91,813
Other assets	6,090	3,282
Property, plant and equipment	603,308	554,559
Total assets	678,770	649,654
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	61,708	64,548
Fair value of financial instruments	1,757	2,925
Future income taxes	424	10,485
Bank debt	173,900	150,450
Total current liabilities	237,789	228,408
Asset retirement obligation	6,588	5,834
Future income taxes	47,203	47,604
Total liabilities	291,580	281,846
SHAREHOLDER'S EQUITY		
Share capital	282,990	241,673
Contributed surplus	5,300	3,977
Retained earnings and accumulated other comprehensive income	98,900	122,158
Total shareholder's equity	387,190	367,808
Total liabilities and shareholder's equity	678,770	649,654

Statement of Retained Earnings and Accumulated Other Comprehensive Income

Twelve months ended December 31,	2009	2008
Retained earnings and other comprehensive income, beginning of year	122,158	77,919
Net earnings and comprehensive income	(23,258)	44,239
Retained earnings and other comprehensive income, end of year	98,900	122,158

Statement of Earnings

Twelve months ended December 31,	2009	2008
REVENUE		
Oil and gas	172,613	263,337
Royalties	(22,968)	(58,449)
Realized gain (loss) on financial instruments	34,294	(19,766)
Unrealized gain (loss) on financial instruments	(33,523)	32,304
Total revenue	150,416	217,426
EXPENSES		
Production	53,123	41,376
Transportation	3,819	2,314
Interest and financing	5,025	6,122
General and administrative	3,947	3,950
Stock based compensation	2,362	1,858
Depletion, depreciation and accretion	101,808	85,586
Provision for non-recoverable accounts receivable	13,233	17,986
Total expenses	183,317	159,192
Earnings before taxes	(32,901)	58,234
Provision for (recovery of) future income taxes	(9,643)	13,995
Net earnings and comprehensive income	(23,258)	44,239

Statement of Cash Flows

Twelve months ended December 31,	2009	2008
OPERATING ACTIVITIES		
Net earnings	(23,258)	44,239
Items not affecting cash:		
Depletion, depreciation and accretion	101,808	85,586
Provision for non-recoverable accounts receivable	13,233	17,986
Stock based compensation	2,362	1,858
Unrealized loss (gain) on financial instruments	33,523	(32,304)
Future income taxes (recovery)	(9,643)	13,995
Sub-total	118,025	131,360
Settlement of asset retirement obligations	(1,043)	(806)
Change in non-cash operating working capital	(13,261)	(41,300)
Cash provided by operating activities	103,721	89,254
FINANCING ACTIVITIES		
Increase in bank debt	23,450	30,550
Issue of common shares, net of costs	39,798	46,623
Cash provided by financing activities		77,173
INVESTING ACTIVITIES		
Property, plant and equipment expenditures	(146,964)	(138,396)
Property, plant and equipment acquisitions	(2,172)	(49,406)
Property, plant and equipment dispositions	375	4,325
Change in other assets	(2,808)	1,000
Change in non-cash investing working capital	(15,431)	13,041
Cash used in investing activities	(167,000)	(169,436)
Net change in cash and cash equivalents	(31)	(3,009)
Cash and cash equivalents, beginning of year	73	3,082
Cash and cash equivalents, end of year	42	73