



PRESS RELEASE

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CELTIC REPORTS 2008 FINANCIAL RESULTS HIGHLIGHTED BY SIGNIFICANT INCREASES IN FUNDS FROM OPERATIONS AND EARNINGS

Celtic Exploration Ltd. (“Celtic” or the “Company”) has released its operating results for the three months and twelve months ended December 31, 2008. Summary of results are as follows:

(\$000's, unless otherwise specified)	Three months ended December 31,			Twelve months ended December 31,		
	2008	2007	Change	2008	2007	Change
Revenue, before royalties and financial instruments	51,842	45,734	13%	263,337	151,443	74%
Funds from operations	32,049	23,246	38%	131,360	83,340	58%
Basic (\$/share)	0.78	0.62	26%	3.28	2.34	40%
Diluted (\$/share)	0.78	0.61	28%	3.27	2.32	41%
Net earnings	29,585	3,507	744%	44,239	8,198	440%
Basic (\$/share)	0.72	0.09	700%	1.10	0.23	378%
Diluted (\$/share)	0.72	0.09	700%	1.10	0.23	378%
Capital expenditures, net of dispositions	42,774	25,156	70%	183,477	179,789	2%
Total assets				649,654	490,431	32%
Bank debt, net of working capital				136,595	136,249	0%
Bank debt, net of working capital, excluding non-cash financial instruments				160,187	136,901	17%
Shareholder's equity				367,808	281,463	31%
Common shares outstanding (thousands)				41,306	37,666	10%
Stock options outstanding (thousands)				3,229	2,826	14%
Weighted average common shares						
Basic (thousands)	41,207	37,641	9%	40,047	35,543	13%
Diluted (thousands)	41,264	38,016	9%	40,141	35,864	12%

Celtic previously released its operating results for the three months and twelve months ended December 31, 2008. These results are summarized in the table below:

	Three months ended December 31,			Twelve months ended December 31,		
	2008	2007	Change	2008	2007	Change
Production						
Oil [BBLs/d]	3,554	3,230	10%	3,404	3,107	10%
Gas [MCF/D]	51,029	35,898	42%	46,000	28,599	61%
Combined [BOE/D]	12,059	9,213	31%	11,071	7,873	41%
Production per million shares [BOE/D]						
	293	245	20%	276	222	24%
Drilling activity						
Total wells	14	8	75%	54	65	-17%
Working interest wells	10.2	8.0	28%	41.1	56.0	-27%
Success rate on working interest wells	100%	100%		88%	81%	
Undeveloped land						
Gross acres				318,969	327,050	-2%
Net acres				246,629	248,135	-1%
Reserves						
Oil & NGLs [MMBBLs]				14,372	11,897	21%
Natural gas [MMCF] *				232,831	131,253	77%
Combined [MBOE]				53,177	33,773	57%
Finding, development & acquisition cost						
Proved [\$ /BOE]				\$19.43	\$21.45	-9%
Proved plus Probable [\$ /BOE]				\$12.24	\$19.27	-36%
Recycle ratio [P+P]						
				2.9 x	1.7 x	
Net asset value per share						
NPV 10%, before tax				\$18.97	\$11.80	61%
NPV 8%, before tax				\$21.18	\$12.99	63%

* Natural gas reserves do not include sulphur reserves of 252,200 long tones at December 31, 2008 and 160,300 long tones at December 31, 2007.

PRESIDENT'S MESSAGE

Celtic is pleased to report to shareholders on the Company's activities in 2008. Once again, Celtic achieved superior financial and operating results in 2008. The Company reported record earnings and funds from operations for the year and at the same time retained financial flexibility by maintaining a strong balance sheet.

Highlights of 2008 results include record earnings of \$44.2 million (\$1.10 per share, diluted), record funds from operations of \$131.4 million (\$3.27 per share, diluted), record production of 11,071 BOE per day, record reserves of 53.2 million BOE and a prudent financial position with debt, net of working capital of \$136.6 million or 1.0 times trailing funds from operations.

A large part of the Company's success has been a result of the continued expansion of the Triassic Montney development prospect at Celtic's most active operating area, Kaybob, Alberta.

Celtic allocated the majority of its 2008 capital program to its Kaybob Montney development prospect. This has allowed the Company to reap substantial rewards from one of the most exciting plays in the Western Canadian Sedimentary Basin. In early 2008, the Montney tight gas play became the "buzz" word in the industry, as numerous investment analysts' commenced research on this developing play. Celtic got a head start before all the publicity and in the previous three years, the Company was actively acquiring land and drilling wells that led to the discovery of four Montney natural gas pools in the greater Kaybob area. In addition, the Company drilled numerous horizontal wells with relatively new multi-fracture technology allowing it to develop this potentially vast

resource, in an economic manner. This head start ahead of the rest of the industry has allowed Celtic to gain a stronghold in what it believes to be one of the premier areas for Montney development in western Canada.

The Montney formation at Kaybob can be produced economically with vertical wells; however, Celtic has discovered that economics are enhanced substantially with horizontal drilling and multi-stage fracture completion techniques. Initially, the Company's horizontal wells were drilled and completed using a five-stage fracture configuration. With success there, the Company began using a seven-stage fracture configuration. Most recently, Celtic has employed eleven-stage fractures with positive results. To date, the highest average initial raw natural gas production rate in the first seven days for a well completed with a five-stage fracture configuration has been 8.4 mmcf per day; for a well completed with a seven-stage fracture configuration, the highest initial production rate in the first seven days has been 9.5 mmcf per day and even though the Company has only completed three wells with an eleven-stage fracture configuration, the highest initial raw natural gas production in the first seven days for this type of well has been 14.6 mmcf per day. The average shrinkage for Montney gas at Kaybob in 2008 was approximately 12%. In addition, the average liquids content (50% NGLs and 50% condensate) is approximately 26 bbls/mmcf of raw gas. As a result of the Company's recent success with eleven-stage fracture completions, Celtic expects to realize significant gains in productivity 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.

Celtic has approximately 100 net sections (64,000 net acres) of land with Montney rights. In 2008, with the discovery of a fifth Montney natural gas pool in the greater Kaybob area, the Company has mapped the productive zone over approximately half of its acreage. This gives Celtic a future inventory of over 120 un-drilled locations in its known pools, leaving significant upside on its unproved Montney acreage. Celtic's first two Montney discoveries at Kaybob South and KayFox have been approved for drill spacing of five wells per section and the Company is confident that its other Montney pools will be granted similar well spacing in the future.

The Company has applied its horizontal multi-stage fracture technology to another formation in the Kaybob area with similar results. The Cretaceous Bluesky formation has similar characteristics to the Triassic Montney and the Company has plans to drill several Bluesky wells in 2009. Based on initial production rates from the first two horizontal wells recently drilled into the Bluesky formation, Celtic is encouraged that similar reserves per well could be recovered from a Bluesky horizontal to that of a Montney horizontal. However, well spacing per section is expected to be lower at two to three wells per section. Total capital costs to drill and complete a Bluesky horizontal well are expected to average 10% to 20% less than the cost of a Montney horizontal well, primarily due to the shallower vertical depth of the Bluesky formation. Celtic has approximately 50 gross (31 net) sections of land in the greater Kaybob area with Cretaceous rights.

In addition to the Triassic Montney and Cretaceous Bluesky formations, Celtic has also had success developing the Jurassic Nordegg formation at Kaybob. The Company expects to apply for regulatory approval to commingle Nordegg production with existing Montney producing wells at KayFox in wells where both formations appear productive. This will enable the Company to further develop the Nordegg formation without having to drill separate Nordegg wells. Celtic expects to have commingling approval in place by late 2009 or early 2010.

Approximately 15% of Celtic's 2009 drilling budget will be incurred outside of the greater Kaybob area. The Company has several low risk development projects at Utikuma in northern Alberta and also at its core producing areas of southern Alberta. However, only a limited amount of capital will be incurred in these areas during 2009, primarily due to the more superior economics generated by the projects in the greater Kaybob area of west central Alberta.

Celtic did commence to deploy some capital to a prospect outside of Kaybob in 2008 resulting in a new oil discovery at Edwand/Figure Lake in east central Alberta. Prior to this oil discovery, Edwand/Figure Lake was predominantly considered a shallow natural gas exploration area, as there was no oil production in the near vicinity. In early 2008, the Company drilled a discovery well that proved to be productive, yielding 15° API oil. Due to the terrain in the area, Celtic deferred further drilling to more suitable winter conditions. During the first quarter of 2009, the Company expects to drill two horizontal wells, testing the multi-stage fracture completion technique on at least one of the wells.

As we enter 2009 surrounded by the most difficult economic environment in recent memory, Celtic has positioned itself to face the challenge. With our risk management program that includes financial derivative instruments on oil prices, NYMEX to AECO natural gas basis differentials and interest rates, the Company has secured a significant portion of its capital expenditure budget for 2009. We look forward to continued growth in assets and cash flow in the coming years.

2008 Highlights

The year ended December 31, 2008 was another successful year in the execution of the Company's growth strategy. Highlights for 2008 are as follows:

- Drilled 54 (41.1 net working interest) wells during 2008 resulting in 7 (4.9 net) oil wells, 39 (30.9 net) natural gas wells and 3 (0.6 net) coal bed methane wells, for an overall success rate, based on net wells, of 88%;
- Increased average daily production by 41% to 11,071 BOE per day, up from 7,873 BOE per day in 2007 and achieved daily average production per million shares of 276 BOE per day, up 24% in 2008 compared to 222 BOE per day in the previous year;
- Increased proved plus probable reserves by 57% to 53.2 million BOE, up from 33.8 million BOE at December 31, 2007 and replaced 2008 production by a factor of 5.8 times;
- Reported finding, development and acquisition cost of \$12.24 per BOE resulting in a recycle ratio of 2.9 times based on proved plus probable reserves;
- Reported net asset value per share at year-end of \$18.97, based on net present value of reserves discounted at 10%, before tax and \$21.18 per share using an 8% discount rate, before tax;
- Accumulated over 100 net sections of land in the greater Kaybob area where the Company is actively developing natural gas prospects in the Montney, Nordegg and Bluesky formations;
- Generated gross proceeds of \$43.1 million by completing an equity financing that resulted in the issuance of 2.9 million common shares at a price of \$15.00 per share;
- Reported funds from operations per share, diluted, of \$3.27, an increase of 41% from \$2.32 per share in the previous year; and
- Reported earnings per share, diluted, of \$1.10, an increase of 378% compared to \$0.23 per share in 2007.

Production

Oil and gas production in 2008 increased 41% to average 11,071 BOE per day compared to 7,873 BOE per day in 2007. Average production in the fourth quarter of 2008 was 12,059 BOE per day, up 31% from 9,213 BOE per day in the fourth quarter of 2007. Production per million shares outstanding in 2008 averaged 276 BOE per day, up 24% from 222 BOE per day in 2007.

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, Michichi and Richdale 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 and Figure Lake. In Northern Alberta, the Company produces mainly light oil from Ogston, Otter and Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob, Fox Creek and Swan Hills. West Central Alberta was the Company's most active drilling area in 2008 and approximately 82% of Celtic's production in 2008 came from this area.

Revenue

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the year ended December 31, 2008 was \$263.3 million, an increase of 74% compared to \$151.4 million in the previous year. For the three months ended December 31, 2008, revenue was \$51.8 million, up 13% from \$45.7 million in the fourth quarter of 2007.

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, 2008 was \$60.12 per BOE, an increase of 9% compared to the previous year. For the three months ended December 31, 2008, the average adjusted product price received was \$51.30 per BOE, down 5% from the average adjusted price received in the fourth quarter of 2007.

Oil Operations

Oil production for the year ended December 31, 2008 averaged 3,404 bbls per day, an increase of 10% compared to the previous year. For the three months ended December 31, 2008, average oil production was 3,554 bbls per day, up 10% from the fourth quarter of 2007. Increases in oil production in 2008 were primarily due to the incremental condensate and NGLs produced at Kaybob.

The average price received for oil sales, after realized financial instruments, for the year ended December 31, 2008 was \$82.45 (\$90.48 before financial instruments) per barrel, up 20% from the average price of \$68.95 (\$69.02 before financial instruments) per barrel received in 2007. The average price received for oil sales, after realized financial instruments, for the fourth quarter ended December 31, 2008 was \$68.63 (\$52.81 before financial instruments) per barrel, down 6% from the average price of \$73.30 (\$79.21 before financial instruments) per barrel received in the fourth quarter of 2007.

For the twelve months ended December 31, 2008, average oil royalties were 27.5% of revenue, after financial instruments (25.1% of sales, before financial instruments). In the previous year, average oil royalties were 22.5% of revenue, after financial instruments (22.4% of sales, before financial instruments). Higher royalty rates, before financial instruments, in 2008 were primarily a result of higher oil prices received, compared to the previous year. For the quarter ended December 31, 2008, average oil royalties were 18.5% of revenue, after financial instruments (24.0% of sales, before financial instruments). In the fourth quarter of the previous year, average oil royalties were 26.3% of revenue, after financial instruments (24.4% of sales, before financial instruments).

Transportation expenses for oil production in 2008 averaged \$0.53 per barrel compared to \$0.71 per barrel in 2007. Lower per unit transportation expenses in 2008 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 2008 averaged \$0.41 per barrel compared to \$0.80 per barrel in the fourth quarter of 2007.

For the year ended December 31, 2008, production expenses were \$13.76 per barrel, an improvement from the previous year's \$13.99 per barrel. During the fourth quarter of 2008, production expenses averaged \$12.95 per barrel compared to \$14.50 per barrel in the fourth quarter of 2007. Lower per barrel production expenses in 2008 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 crude oil.

Gas Operations

Gas production for the year ended December 31, 2008 averaged 46,000 mcf per day, an increase of 61% compared to 28,599 mcf per day in the previous year. Increases in gas production in 2008 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, 2008 averaged 51,029 mcf per day, an increase of 42% 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, 2008 was \$8.37 (\$8.94 before financial instruments) per mcf, up 8% from the average price of \$7.76 (\$7.01 before financial instruments) per mcf received in 2007. The average price received for gas sales, after realized financial instruments, for the fourth quarter ended December 31, 2008 was \$7.36 (\$7.36 before financial instruments) per mcf, up 1% from the average price of \$7.29 (\$6.72 before financial instruments) per mcf received in the fourth quarter of 2007.

For the year ended December 31, 2008, average gas royalties were 21.4% of revenue, after financial instruments (20.0% of sales, before financial instruments). In the previous year, average natural gas royalties were 17.9% of revenue, after financial instruments (19.8% of sales, before financial instruments). Actual Crown natural gas royalties payable are based on an Alberta reference price and not on actual corporate realized prices. For the quarter ended December 31, 2008, average natural gas royalties were 19.2% of revenue, after financial instruments (19.2% of sales, before financial instruments). In the fourth quarter of the previous year, average natural gas royalties were 19.5% of revenue, after financial instruments (21.1% of sales, before financial instruments).

Transportation expenses for the year ended December 31, 2008 were \$0.10 per mcf, a decrease of 37% compared to \$0.16 per mcf for the previous year. Lower transportation expenses in 2008 reflect the Company's ownership in the majority of the pipeline infrastructure at its main producing area of Kaybob, Alberta. Transportation expenses for the fourth quarter ended December 31, 2008 were \$0.11 per mcf, a decrease of 21% compared to \$0.14 per mcf for the same period in the previous year.

For the twelve months ended December 31, 2008, production expenses of \$1.44 per mcf were 6% lower than \$1.54 per mcf in the previous year. Lower production expenses in 2008 reflect the increasing portion of Kaybob production as a percentage of the Company's total production base, where costs are lower than the corporate average. For the fourth quarter ended December 31, 2008, production expenses were \$1.45 per mcf compared to \$1.41 per mcf in the fourth quarter of 2007.

Interest Expense

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including Alberta Treasury Branches, Canadian Western Bank and Fortis Capital (Canada) Ltd. The authorized borrowing amount under this facility is \$200.0 million. The facilities are available for a period of 364 days, maturing on June 30, 2009. 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 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 to bank prime plus 1.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and a half 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 0.85% to 2.5%, depending upon the Company's then current debt to cash flow ratio of between less than one times to greater than three times.

The Company had a fixed rate bankers' acceptance in the amount of \$20.0 million that matured on February 12, 2009 at an annual interest rate of 2.6%, before bank stamping fees. The Company has a fixed rate bankers' acceptance in the amount of \$30.0 million maturing on May 12, 2009 at an annual interest rate of 0.95%, before bank stamping fees. In addition, 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, 2010 has been fixed at an annual interest rate of 3.2%, before bank stamping fees.

Interest expense for the year was \$6.1 million at an average rate of 4.8% compared to \$6.3 million at an average rate of 5.8% in 2007.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2008 were \$4.0 million or \$0.97 per BOE compared to \$3.0 million or \$1.06 per BOE in 2007. General and administrative expenses are reduced by overhead recovered on Company operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized.

Stock Based Compensation Expense

For the year ended December 31, 2008, stock based compensation expense was \$1.9 million, compared to \$1.5 million in 2007.

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 capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated 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.

Depletion, depreciation and accretion expense for the period ended December 31, 2008 was \$85.6 million or \$21.13 per BOE, compared to the previous year's amount of \$63.5 million or \$22.09 per BOE.

Taxes

In 2008, Celtic recorded a provision for future income taxes in the amount of \$14.0 million and in 2007, Celtic provided for a recovery of future income taxes in the amount of \$2.5 million. These amounts differ from the expected provision for income taxes of \$17.2 million in 2008 (\$1.8 million in 2007) based on the statutory combined income tax rate of 29.5% in 2008 (32.1% in 2007) due to the differences between non-deductible stock based compensation costs and the recognition of a benefit primarily relating to substantively enacted changes to future federal income tax rates.

At December 31, 2008, Celtic had estimated unused income tax deductions available of approximately \$365.1 million.

Funds from Operations

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, 2008 was \$131.4 million (\$3.28 per share, basic and \$3.27 per share, diluted). In 2007, funds from operations were \$83.3 million (\$2.34 per share, basic and \$2.32 per share, diluted). On a barrel of oil equivalent basis, funds from operations in 2008 were \$32.44 per BOE, up 12% from \$29.00 per BOE in 2007. The primary reason for the increase in 2008 was a result of higher oil and gas prices realized during the year. On a barrel of oil equivalent basis, funds from operations in 2007 were \$29.00 per BOE, down 20% from \$36.08 per BOE in 2006. The primary reason for the decrease in 2007 was a result of lower natural gas prices realized during the year.

Net Earnings

Net earnings for the year ended December 31, 2008 was \$44.2 million (\$1.10 per share, basic and diluted). Net earnings for the year ended December 31, 2007 was \$8.2 million (\$0.23 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, Fox Creek and Swan Hills.

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.

Liquidity

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. With the expectation of a continuing global recession in 2009, oil and gas companies will continue to face significant challenges in 2009.

The Company manages liquidity risk through the prudent use of debt, interest rate and commodity price risk management and through an actively managed production and capital expenditure budget process.

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 WTI fixed oil sales price derivative contracts in effect as at December 31, 2008:

Quantity	Remaining term of contract	Fixed price per bbl
2,000 bbls/d (put-call spread)	January 1 to December 31, 2009	CA\$115.00 (floor) CA\$145.00 (cap)

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2008:

Quantity	Remaining term of contract	Fixed price per mmbtu
30,000 mmbtu/d (swap)	April 1 to April 30, 2009	US\$0.69
10,000 mmbtu/d (swap)	May 1 to May 31, 2009	US\$0.69
30,000 mmbtu/d (swap)	June 1 to December 31, 2009	US\$0.69

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, 2008:

Amount	Remaining term of contract	Fixed interest rate
CA\$80,000,000	January 1, 2009 to April 22, 2010	3.30%
CA\$20,000,000	January 1, 2009 to April 22, 2010	2.54%

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 has been rocked with unprecedented losses and business failures. As a result, the current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited 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 has been secured to a certain extent through the use of commodity price and interest rate financial derivative instruments.

The Company has reduced its 2009 guidance for funds from operations by lowering its oil and gas price expectations. However, forecasted production and capital spending remains unchanged at this time. Celtic's capital expenditure program for 2009 remains flexible and if the current economic environment continues to deteriorate, the Company has the ability to defer expenditures into the future.

2009 Guidance

On March 3, 2009, the Government of Alberta announced new incentive programs to encourage additional activity in the province's conventional oil and gas sectors. These new incentives include a royalty credit of \$200 per meter drilled on new conventional oil and natural gas wells and a royalty reduction that provides a maximum five-per-cent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010, for up to 12 months production or the first 50,000 barrels of oil or 500,000 mcf of natural gas produced from a new well. The Company is currently evaluating the impact of these new incentive programs and based on initial indications, it appears to be favourable resulting in increased forecasted funds from operations over the next 24 months commencing April 1, 2009. The 2009 guidance provided below does not take into consideration the impact of these new incentive programs. The Company expects to provide updated guidance in the near future after full evaluation of the effect of these new incentives is completed.

Despite the current economic environment, Celtic remains optimistic about its future prospects. Since commencing operations, the Company was successful in establishing a production base during the early months that provides a cash flow stream that can be re-invested into Celtic's ongoing exploration and development activity. 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 potential.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of \$150 million for 2009. This capital spending will be financed by funds from operations and available bank credit lines.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2009, estimated decline rates on existing and new volumes and the planned turnaround at the KA Gas Plant in May 2009, Celtic expects production in 2009 to average between 13,800 and 14,200 BOE/d (25% oil and 75% gas). This represents a 25% to 28% increase from the average production of 11,071 BOE/d in 2008. The KA Gas Plant maintenance is expected to result in approximately 10,000 BOE/d of Celtic production to be shut-in during the month of May 2009. Celtic expects to exit 2009 with production of approximately 16,500 BOE/d.

Financial turmoil and the global recession continue to remain in the headlines and could continue to put pressure on oil and gas prices in the future. The insatiable appetite for oil demonstrated by countries such as India and China, in the past two years, has temporarily slowed down. As a result of these and other factors, Celtic expects oil prices to be significantly lower in 2009 compared to 2008. Industrial demand for natural gas in North America has also been reduced as a result of the weakening economy, at the same time when natural gas supply in the United States was increasing. Both these factors have contributed to lower natural gas prices, despite the increased demand for natural gas that was created by a colder than average winter. Celtic also expects much weaker average natural gas prices in 2009 compared to 2008. However, with the rapid decrease in active rigs drilling for gas in North America and with the expected decline of new "flush" natural gas production recently brought on-stream in the United States, the Company is optimistic that natural gas prices could recover towards the end of 2009.

The Company's average commodity price assumptions for 2009 have been reduced to US\$35.00 per barrel for WTI oil (previously US\$65.00 per barrel), US\$4.80 per mmbtu for NYMEX natural gas (previously US\$7.00 per mmbtu), \$4.90 per GJ for AECO natural gas (previously \$6.54 per GJ) and a US/Canadian dollar exchange rate of US\$0.786 (previously US\$0.870). These prices compare to 2008 average prices of US\$99.65 per barrel for WTI oil, US\$8.93 per mmbtu for NYMEX natural gas, \$7.71 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.937.

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 2009 is forecasted to be approximately \$135.0 million or \$3.27 per share (\$3.22 per share, diluted) and net loss is forecasted to be approximately \$6.8 million or \$0.17 per share (\$0.17 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 reach \$175.0 million by the end of 2009 or approximately 1.3 times forecasted 2009 funds from operations.

Celtic's capital expenditure budget for 2009 will see the Company participate at high working interests in the drilling of approximately 45 to 50 wells during the year, of which approximately 80% 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, earnings and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2009 and beyond.

The information set out herein under the heading “2009 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. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Common 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, 2008, there were 41.3 million common shares outstanding. There were no preferred shares outstanding. As at December 31, 2008, directors, employees and certain consultants have been granted options to purchase 3.2 million common shares of the Company at an average exercise price of \$12.96 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 under the symbol “CLT”.

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.

For further information, please contact:

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Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer (403) 215-5310.

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, 2008 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 27, 2009. 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, 2008	As at December 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	73	3,082
Accounts receivable	50,728	25,751
Prepaid expenses and deposits	4,010	646
Fair value of financial instruments	36,154	925
Future income tax asset	848	-
Total current assets	91,813	30,404
Other assets	3,282	4,281
Property, plant and equipment	554,559	455,746
Total assets	649,654	490,431
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	64,548	46,480
Fair value of financial instruments	2,925	-
Future income taxes	10,485	273
Bank debt	150,450	119,900
Total current liabilities	228,408	166,653
Asset retirement obligation	5,834	5,719
Future income taxes	47,604	36,596
Total liabilities	281,846	208,968
SHAREHOLDER'S EQUITY		
Share capital	241,673	200,180
Contributed surplus	3,977	3,364
Retained earnings and accumulated other comprehensive income	122,158	77,919
Total shareholder's equity	367,808	281,463
Total liabilities and shareholder's equity	649,654	490,431

Statement of Earnings

Twelve months ended December 31,	2008	2007
REVENUE		
Oil and gas	263,337	151,443
Royalties	(58,449)	(32,062)
Realized gain (loss) on financial instruments	(19,766)	7,702
Unrealized gain (loss) on financial instruments	32,304	(12,711)
Total revenue	217,426	114,372
EXPENSES		
Production	41,376	31,933
Transportation	2,314	2,509
Interest and financing	6,122	6,268
General and administrative	3,950	3,033
Stock based compensation	1,858	1,453
Depletion, depreciation and accretion	85,586	63,497
Provision for non-recoverable accounts receivable	17,986	-
Total expenses	159,192	108,693
Earnings before taxes	58,234	5,679
Provision for (recovery of) future income taxes	13,995	(2,519)
Net earnings and comprehensive income	44,239	8,198

Statement of Retained Earnings and Accumulated Other Comprehensive Income

Twelve months ended December 31,	2008	2007
Retained earnings and other comprehensive income, beginning of year	77,919	69,721
Net earnings and comprehensive income	44,239	8,198
Retained earnings and other comprehensive income, end of year	122,158	77,919

Statement of Cash Flows

Twelve months ended December 31,	2008	2007
OPERATING ACTIVITIES		
Net earnings	44,239	8,198
Items not affecting cash:		
Depletion, depreciation and accretion	85,586	63,497
Provision for non-recoverable accounts receivable	17,986	-
Stock based compensation	1,858	1,453
Unrealized loss (gain) on financial instruments	(32,304)	12,711
Future income taxes (recovery)	13,995	(2,519)
Sub-total	131,360	83,340
Settlement of asset retirement obligations	(806)	(1,021)
Change in non-cash operating working capital	(41,300)	2,772
Cash provided by operating activities	89,254	85,091
FINANCING ACTIVITIES		
Increase in bank debt	30,550	18,100
Issue of common shares, net of costs	46,623	70,807
Cash provided by financing activities	77,173	88,907
INVESTING ACTIVITIES		
Property, plant and equipment expenditures	(138,396)	(135,566)
Property, plant and equipment acquisitions	(49,406)	(45,636)
Property, plant and equipment dispositions	4,325	1,413
Change in other assets	1,000	(2,568)
Change in non-cash investing working capital	13,041	10,617
Cash used in investing activities	(169,436)	(171,740)
Net change in cash and cash equivalents	(3,009)	2,258
Cash and cash equivalents, beginning of year	3,082	824
Cash and cash equivalents, end of year	73	3,082