

PRE•PARED: ADJECTIVE.

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CELTIC'S 2011 Q3 REPORT

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SINCE STARTING CELTIC  
EXPLORATION IN 2002,  
OUR VISION HAS BEEN  
TO APPLY SOUND  
FINANCIAL PRINCIPLES,  
ACQUIRE QUALITY  
ASSETS AND DELIVER  
SUPERIOR VALUE.

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# FINANCIAL AND OPERATIONAL HIGHLIGHTS

<i>(CA\$ thousands, unless otherwise indicated)</i>	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
<b>FINANCIAL</b>						
Revenue, before royalties and financial instruments	55,298	47,989	15%	163,723	169,000	-3%
Funds from operations	34,626	30,963	12%	102,126	100,168	2%
Basic (\$/common share)	0.35	0.34	3%	1.07	1.12	-4%
Diluted (\$/common share)	0.34	0.34	0%	1.04	1.10	-5%
Profit (loss)	(1,592)	(1,897)	-16%	3,100	27,449	-89%
Basic (\$/common share)	(0.02)	(0.02)	0%	0.03	0.31	-90%
Diluted (\$/common share)	(0.02)	(0.02)	0%	0.03	0.30	-90%
Capital expenditures, net of dispositions and drilling credits	96,682	72,762	33%	238,007	110,724	115%
Total assets	932,905	710,764	31%	932,905	710,764	31%
Bank debt, net of working capital	219,738	168,017	31%	219,738	168,017	31%
Shareholders' equity	547,586	411,704	33%	547,586	411,704	33%
Weighted average common shares outstanding (thousands)						
Basic	97,650	90,089	8%	95,402	89,701	6%
Diluted	100,900	92,110	10%	98,502	91,139	8%
<b>OPERATIONS</b>						
Production						
Oil (bbls/d)	3,859	3,747	3%	3,676	4,061	-9%
Gas (mcf/d)	71,691	76,555	-6%	71,177	79,294	-10%
Combined (BOE/d)	15,808	16,506	-4%	15,539	17,277	-10%
Production per million common shares (BOE/d)	162	183	-11%	163	193	-16%
Realized sales prices, after financial instruments						
Oil (\$/bbl)	79.77	62.29	28%	79.64	67.53	18%
Gas (\$/mcf)	4.18	4.22	-1%	4.24	4.52	-6%
Operating netbacks (\$/BOE)						
Oil and gas revenue	38.02	31.60	20%	38.59	35.83	8%
Realized gain/(loss) on financial instruments	0.40	2.13		(0.33)	0.78	
Realized sales price, after financial instruments	38.42	33.73	14%	38.26	36.61	5%
Royalties	(4.45)	(3.14)	42%	(4.25)	(4.27)	0%
Production expense	(7.93)	(8.11)	-2%	(7.49)	(8.70)	-14%
Transportation expense	(0.36)	(0.40)	-10%	(0.41)	(0.47)	-13%
Operating netback	25.68	22.08	16%	26.11	23.17	13%
Drilling activity						
Total wells	12	18	-33%	46	47	-2%
Working interest wells	7.5	12.7	-41%	31.0	33.7	-8%
Success rate on working interest wells	91%	100%	-9%	98%	94%	4%
Undeveloped land						
Gross acres	710,513	494,587	44%	710,513	494,587	44%
Net acres	643,557	432,777	49%	643,557	432,777	49%

# MESSAGE TO SHAREHOLDERS

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders the Company's activities in the third quarter of 2011. During the quarter, Celtic drilled 12 (7.5 net) wells with an overall net success rate of 91%. Production during the quarter averaged 15,808 BOE per day, a decrease of 4% from 16,506 BOE per day in the third quarter of 2010. Production during the third quarter did not reflect the start-up of Resthaven production that Celtic had previously expected to commence in September 2011. Initial production from the Company's Resthaven facility, which is tied into the Simonette Gas Plant, was brought on-stream on October 28, 2011. In addition, partial production from Fir was brought on-stream in late September, with little impact to third quarter average production volumes. With the start-up of Resthaven and Fir production, Celtic expects to show significant production growth in the fourth quarter of 2011.

In the third quarter of 2011, Celtic recorded funds from operations of \$34.6 million (\$0.34 per share, diluted), up 12% from \$31.0 million (\$0.34 per share, diluted) reported in the same quarter of the previous year. Despite lower production levels during the third quarter, funds from operations increased primarily due to a higher realized average sales price and lower production and transportation expense per BOE.

Net capital expenditures during the quarter were \$96.7 million and bank debt, net of working capital, at September 30, 2011 was \$219.7 million, up 31% from \$168.0 million at September 30, 2010.

Subsequent to the end of the third quarter, Celtic issued 6.9 million common shares by way of short-form prospectus for gross proceeds of \$172.5 million. Also, subsequent to the end of the third quarter, the Company announced that it had entered into an agreement to acquire natural gas assets, including production of approximately 2,500 BOE per day, at Grande Cache, Alberta, adjacent to Celtic's core area at Resthaven, for cash consideration of \$50.0 million.

## **DRILLING AND OPERATIONS**

At Kaybob, Alberta, the Company drilled two (1.9 net) Triassic Montney horizontal wells and one (0.3 net) Cretaceous Bluesky horizontal well. Also at Kaybob, Celtic participated in the drilling of two (0.2 net) Devonian Beaverhill Lake wells in the Kaybob South BHL Unit # 1, one (0.1 net) of which was unsuccessful.

At Inga, British Columbia, Celtic participated in the drilling of two (0.8 net) Triassic Doig horizontal wells. The first well located at 04-36-087-23W6 (40% WI) was completed and after a five day test, the well was producing oil at a rate of 1,070 barrels per day and natural gas at a rate of 3.5 MMCF per day (1,650 BOE per day combined), at a flowing wellhead pressure of 12,627 kPa (1,830 psi). The second well located at 01-33-087-23W6 (40% WI) will be completed in the fourth quarter.

At Fir, Alberta, the Company drilled one (0.7 net) horizontal well with a measured depth of approximately 4,000 metres. This well, located at 08-27-059-22W5 will be completed in the fourth quarter.

In the Greater Resthaven area of Alberta, Celtic carried out three operations which further delineate this exciting Triassic Montney play. The Company drilled two (2.0 net) horizontal wells and drilled one (1.0 net) re-entry horizontal well during the third quarter of 2011.

# CELTIC MAINTAINS ITS EXIT 2011 PRODUCTION GUIDANCE OF 24,500 BOE PER DAY AS MONTNEY PRODUCTION COMMENCES FROM RECENTLY CONSTRUCTED INFRASTRUCTURE AT RESTHAVEN AND FIR.

The first horizontal well that was drilled during the third quarter is located north of the Simonette River near Jayar at 04-34-061-03W6 (100% WI). The well was drilled to a measured depth of 5,130 metres and was completed with a 16-stage foam fracture technique. After 82 hours of clean-up and flow, at the end of the test, the well was producing natural gas at a rate of 20.4 MMCF per day and condensate at 568 barrels per day, at a flowing wellhead pressure of 12,863 kPa (1,837 psi).

The second horizontal well that was drilled during the third quarter is in the central part of Celtic's Greater Resthaven land block near Wanyandie located at 01-03-060-01W6 (100% WI). The well was drilled to a measured depth of 4,597 metres and was completed with a 13-stage foam fracture technique. During the last 24 hours of the 6 day test, the well was flowing natural gas at a rate of 4.1 MMCF per day and condensate of 48 barrels per day, at a flowing wellhead pressure of 1,052 kPa (150 psi).

The third operation during the third quarter was a re-entry horizontal well located near Simonette at 04-11-062-27W5 (100% WI). This well was intended to test an eight section block near Simonette, away from Celtic's contiguous block of lands in the Greater Resthaven area. The well has been completed and is currently being tested.

Celtic has been active at recent Alberta crown land sales in the Resthaven area. The company has increased its land holdings with Triassic Montney rights to 461,357 gross acres (720 sections) and 443,254 net acres (692 sections).

At Resthaven, Celtic has completed the Phase I construction of gas gathering pipelines and a central compression and dehydration facility located at 02-10-060-01W6 (the "Resthaven facility"). The Company has started operating the Resthaven facility, with the first compressor running, since October 28, 2011. Natural gas from the Resthaven facility is pipeline (12 inch) connected to the Simonette gas plant operated by Keyera Corp. Two 100% working interest horizontal wells have been tied-in to the Resthaven facility which is currently producing at the first compressor's maximum capacity of 12.7 million cubic feet per day.

A second compressor with a capacity of 15.3 million cubic feet per day is expected to start up next week, at which time, four additional 100% working interest horizontal wells are expected to be tied-in to the Resthaven facility. As a result, Celtic has aggregate capacity of 28.0 million cubic feet per day from Phase I construction.

Phase II construction is currently underway as Celtic extends the gas gathering pipeline system north of the Simonette River. As part of this construction phase, the Company expects to install a third compressor and additional dehydration facilities by late December 2011, expanding the aggregate capacity of the Resthaven facility to 50.0 million cubic feet per day.

Phase III construction will commence in 2012, at which time the Company intends to extend its gas gathering pipelines to the wells located in the southern block of its contiguous land holdings. Celtic currently has four rigs operating in the Resthaven area, drilling horizontal wells and expects to keep these rigs operating throughout 2012 further delineating and de-risking the Company's 692 section Triassic Montney land base.

## **OUTLOOK**

In spite of continued AECO natural gas prices below \$4.00 per GJ, Celtic is able to generate profitable returns on its investments due to the nature of its asset base that is primarily made up of predictable and repeatable resource type development in liquids-rich natural gas formations.

Given the success from recent well completions, Celtic maintains its exit 2011 production guidance of approximately 24,500 BOE per day. However, due to the K3 Gas Plant outage and pipeline and facility construction delays, certain production at Fir and Resthaven were brought on-stream later than originally forecasted. As a result, average production for 2011 has been reduced to 16,800 BOE per day (previously 18,400 BOE per day).

Celtic's Board of Directors has approved the company's 2012 capital expenditure budget of \$375.0 million. Oil and gas production for 2012 is forecasted to average between 27,500 and 28,000 BOE per day. Celtic's previous announcement whereby it has entered into an agreement to acquire assets at Grande Cache, Alberta is not reflected in the guidance provided herein as that transaction is not expected to close until December 2011.

The Company is excited about its active exploration program and looks forward to updating shareholders with further results in the near future. Celtic continues to maintain a flexible financial position so that it can pursue opportunities as they arise.

On behalf of the Board of Directors,



**David J. Wilson**

President and Chief Executive Officer  
November 9, 2011

# MANAGEMENT'S

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# DISCUSSION & ANALYSIS

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## **INTRODUCTION**

**The Company was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT".**

The following management's discussion and analysis ("MD&A") is dated November 9, 2011 and should be read in conjunction with the Company's unaudited condensed interim financial statements and related notes for the period ended September 30, 2011, which have been prepared in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting". On January 1, 2011, the Company adopted International Financial Reporting Standards ("IFRS"). In the previous year, the Company prepared its financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). As per the requirements of IFRS 1 "First time adoption of International Financial Reporting Standards", comparative information for 2010 has been restated in accordance with the Company's IFRS accounting policies. The accompanying financial statements have been prepared by management and approved by the Company's Audit Committee and Board of Directors.

Additional information relating to Celtic can be found on the SEDAR website at [www.sedar.com](http://www.sedar.com).

## **FORWARD-LOOKING STATEMENTS**

This document contains expectations, beliefs, plans, goals, objectives, assumptions, information and statements about future events, conditions, results of operations or performance that constitute "forward-looking information" or "forward-looking statements" (collectively, "forward-looking statements") under applicable securities laws. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. We caution that the foregoing list of risks and uncertainties is not exhaustive. Events or circumstances could cause actual dates to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The forward-looking statements contained in this press release are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

The information set out herein with respect to forecasted 2011 results 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 2011. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

## **NON-GAAP AND NON-IFRS MEASURES**

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") or International Financial Reporting Standards ("IFRS"). As these measures are commonly used in the oil and gas industry, the Corporation believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. "Operating netback" is calculated by deducting royalties, production expenses and transportation expenses from oil and gas revenue. "Funds from operations" is calculated by adding back settlement of decommissioning obligations and change in non-cash operating working capital to cash provided by operating activities. Funds from operations and operating netbacks are used by Celtic as key measures of performance and are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, profit or other measures of financial performance calculated in accordance with GAAP and IFRS. "Net debt" is calculated as bank debt plus other current liabilities less current assets, and is used by the Corporation to assess liquidity and general financial strength. Net debt should not be considered an alternative to, or more meaningful than current assets or current liabilities as determined in accordance with GAAP and IFRS.

The following table reconciles cash provided by operating activities to funds from operations:

(CA\$ thousands)	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Cash provided by operating activities	<b>28,746</b>	40,385	<b>88,223</b>	116,758
Settlement of decommissioning obligations	<b>1,896</b>	-	<b>1,915</b>	-
Change in non-cash operating working capital	<b>3,984</b>	(9,422)	<b>11,988</b>	(16,590)
Funds from operations	<b>34,626</b>	30,963	<b>102,126</b>	100,168

## 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.

## CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of IFRS that have a significant impact on the financial results of the Company. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The following discussion highlights the significant changes in the Company's critical accounting estimates from those disclosed in the MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

### Adoption of International Financial Reporting Standards

The condensed interim financial statements are for part of the period covered by the first IFRS annual financial statements of the Company and IFRS 1, "First-time Adoption of International Financial Reporting Standards" has been applied. The impact of IFRS on the Company's previously reported financial statements for the year ended December 31, 2010 and opening balance sheet as at January 1, 2010 is disclosed in the Company's unaudited interim financial statements for the period ended March 31, 2011. Note 18 to the condensed interim financial statements presents reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the statement of changes in shareholders' equity as at September 30, 2010 and the statement of profit (loss) and comprehensive income (loss) for the three and nine months ended September 30, 2010.

Comparative financial information is required on first time adoption of IFRS and therefore the Company has adopted IFRS as at January 1, 2010 (the "Transition Date"). IFRS generally requires full retrospective application of the standards in effect; however, IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to this requirement.

The Company has applied the following optional exemptions:

**Full cost oil and gas accounting** - IFRS 1 provides the option for entities using full cost accounting for oil and gas activities under previous GAAP to measure oil and gas assets at the Transition Date at the historical net book value or at fair value, rather than applying IFRS rules retrospectively. The Company elected to measure its oil and gas assets at the net book value determined under previous GAAP, resulting in undeveloped land costs being reclassified to E&E assets. The remaining development and production

assets that were accumulated in a country cost centre under previous GAAP could be allocated to the cost centre's underlying assets pro-rata using reserve volumes or values. The Company elected to allocate these assets using reserve quantities.

**Decommissioning obligations** - For entities taking the full cost exemption described above, IFRS 1 requires that entities measure decommissioning obligations in accordance with IAS 37 "Provisions, Contingent Liabilities and Contingent Assets", as at the Transition Date and that any difference between this amount and the carrying amount of those liabilities determined under the Company's previous GAAP, be recognized directly in retained earnings.

**Share based payments** - IFRS 2 "Share-based Payment", requires retrospective application of its provisions to equity instruments granted after November 7, 2002. The IFRS 1 exemption allows first-time adopters to not apply IFRS 2 to equity instruments that were granted prior to November 7, 2002. It also allows the first-time adopter to not apply IFRS 2 to equity instruments granted after November 7, 2002 that vested before the Transition Date. The Company elected to use these exemptions provided under IFRS 1.

**Business Combinations** - IFRS 3 "Business Combinations" has not been applied to acquisitions that occurred before January 1, 2010.

**Borrowing costs** - IAS 23 "Borrowing Costs", requires capitalization of borrowing costs relating to qualifying assets. The Company elected to apply the IFRS 1 exemption whereby an entity is permitted to commence capitalization of borrowing costs relating to qualifying assets prospectively from January 1, 2010. The Company did not capitalize any borrowing costs under Canadian GAAP and did not identify any qualifying expenditures in 2010.

The impact on the Company's previously reported financial statements for the year ended December 31, 2010 and opening balance sheet as at January 1, 2010 is disclosed in the Company's unaudited interim financial statements for the period ended March 31, 2011. The following provides a summary of significant adjustments to shareholders' equity as at September 30, 2010 and to profit (loss) and comprehensive income (loss) for the three and nine months ended September 30, 2010:

#### **a) Reclassifications**

##### *Gain on derivative financial instruments*

Realized and unrealized gains or losses on derivative financial instruments are presented as a single financial statement line item on the statement of profit (loss) and comprehensive income (loss) and detailed in Note 9 to the financial statements.

##### *Accretion on decommissioning obligations*

Under previous GAAP, accretion on decommissioning obligations was included in depletion, depreciation and accretion. Under IFRS, accretion is presented as a financing expense in the statement of profit (loss) and comprehensive income (loss) and detailed in Notes 7 and 15 to the financial statements.

#### **b) Decommissioning obligations**

In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and IFRS 1, the Company revalued its decommissioning obligations, known as asset retirement obligations under previous GAAP, using a risk free discount rate at January 1, 2010 and recognized the difference directly in retained earnings. Under previous GAAP, the Company's asset retirement obligations were discounted using an average credit-adjusted risk free rate of 8.5%, whereas under IFRS, the Company discounted its decommissioning obligations using an average risk free rate of approximately 3.9%. As a result of discounting the obligation at a lower rate, the value of the Company's decommissioning liability increased by \$14.6 million as of January 1, 2010. Correspondingly, accretion expense for the three and nine months ended September 30, 2010 increased by \$0.1 million and \$0.3 million, respectively. The net increase in accretion expense under IFRS represents the impact of a higher opening obligation as the basis for the expense, partially offset by the application of a lower rate.

### **c) Share based compensation**

Under the previous GAAP, the Company recognized the expense associated with share based compensation on a straight-line basis and did not incorporate a forfeiture rate at the grant date. Conversely under IFRS, the Company is required to recognize the expense using graded vesting awards and make an estimate of the number of options expected to ultimately vest. As a result, share based compensation expense increased by \$0.5 million and \$0.8 million for the three and nine months ended September 30, 2010, respectively, with a corresponding increase in contributed surplus.

### **d) Depletion, depreciation and amortization**

Upon transition to IFRS, the Company adopted a policy of depleting development and production assets on a unit of production basis over proved reserves. The depletion policy under previous GAAP was based on units of production over proved reserves, however depletion was done on the full Canadian cost pool under the previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e. fields or combinations thereof). As a result of depleting at the major area level, depletion, depreciation and amortization expense increased by \$2.8 million for the three months ended September 30, 2010, and by \$4.8 million for the nine months ended September 30, 2010.

### **e) Asset expiries**

Under the previous GAAP, costs associated with mineral leases were classified within property, plant and equipment and excluded from the depletable cost base until expiry, at which point the costs would be recognized as an expense over time through depletion. Under IFRS, mineral leases are classified as E&E and are considered impaired upon expiry. Asset expiries of \$0.8 million and \$1.7 million were recorded for the three and nine months ended September 30, 2010, respectively.

### **f) Gains and losses on the sale of assets**

Under previous GAAP, the Company did not recognize gains or losses on the disposition of capital assets. Rather, the proceeds of sale were charged as a reduction of the full cost pool, given that the disposition did not cause a change in the depletion factor by more than 20%. Under IFRS, a gain (loss) is recorded to the extent that the proceeds exceed (are less than) the carrying amount of the asset. As a result of non-core property dispositions, the Company recognized a gain of \$3.0 million for the quarter ended September 30, 2010, and a cumulative gain of \$32.0 million for the nine months ended September 30, 2010.

### **g) Statement of cash flows**

The transition from previous GAAP to IFRS has had no effect on the cash flows generated by the Company. The reconciling items between the previous GAAP presentation and the IFRS presentation have no net impact on the reported cash flows provided by or used in operating, financing and investing activities.

### **Change in estimated decommissioning obligations**

The Company recorded a significant revision to estimated decommissioning obligations in the period. The increase in the present value of future decommissioning obligations is due to a combination of discounting future cost estimates at a lower rate than in prior periods, and increasing the underlying cost estimates. In prior periods, the Company estimated abandonment and reclamation costs using publicly available industry data as a benchmark. In the current period, an external party was engaged to perform an independent review of the Company's operating locations and provided new information with respect to the estimated costs of future site restoration. The change in estimate has been recognized prospectively by increasing the carrying amount of the decommissioning obligation, with a corresponding addition to the carrying amount of the development and production assets to which the obligations relate. A reconciliation of the movement in the decommissioning obligation as of September 30, 2011 is included in Note 7 to the interim financial statements.

## **CHANGES IN ACCOUNTING POLICIES**

A summary of changes in accounting policies used by Celtic can be found in Note 2 of the Company's September 30, 2011 unaudited condensed interim financial statements.

## **DISCLOSURE CONTROLS AND PROCEDURES**

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

## **INTERNAL CONTROLS OVER FINANCIAL REPORTING**

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the period from July 1, 2011 to September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes were identified during this period.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

## **GROWTH STRATEGY**

The Company implements a full cycle exploration and development program and, at the same time, opportunistically seeks to acquire assets with exploitation potential. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled and retained a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities.

## **RESULTS OF OPERATIONS**

### **THIRD QUARTER 2011 HIGHLIGHTS**

- Drilled 12 (7.5 net working interest) wells during the quarter with an overall success rate of 91%;
- Recorded average daily production of 15,808 BOE per day, down from 16,506 BOE per day in the third quarter of 2010;
- Received an average price of \$38.42 (\$38.02 before hedging) per BOE, up 14% from \$33.73 (\$31.60 before hedging) per BOE in the third quarter of 2010 and recorded an operating netback of \$25.68 per BOE, up 16% from \$22.08 per BOE in the corresponding quarter of 2010; and
- Generated \$34.6 million in funds from operations for the three month period ended September 30, 2011, up 12% from \$31.0 million in the same quarter of the previous year. Reported funds from operations per common share, diluted, of \$0.34 per common share, which is consistent with the third quarter of the previous year.

## PRODUCTION

Oil and gas production in the third quarter of 2011 decreased 4% to average 15,808 BOE per day compared to 16,506 BOE per day in the same quarter of 2010. Production per million common shares outstanding for the three months ended September 30, 2011 averaged 162 BOE per day, down 11% from 183 BOE per day in the corresponding quarter of the previous year. Oil and gas production for the nine months ended September 30, 2011 decreased 10% to average 15,539 BOE per day compared to 17,277 BOE per day in the same period of 2010. Production per million common shares outstanding for the nine months ended September 30, 2011 averaged 163 BOE per day, down 16% from 193 BOE per day in the corresponding period of the previous year.

The decrease in production compared to the year prior is primarily due to non-core property dispositions in 2010 and in the first quarter of 2011. In addition, previously the Company expected to bring on new production at Fir and Resthaven in early September. Due to longer than anticipated lead times to build infrastructure, a portion of Fir production was delayed and brought on-stream in late September. The majority of wells drilled to date at Resthaven are now expected to be tied-in the first week of November. As a result, the Company expects to realize significant growth in production in the fourth quarter.

## REVENUE

Revenue, before royalties, and before gains or losses on financial instruments, for the three months ended September 30, 2011, was \$55.3 million, an increase of 15% compared to \$48.0 million in the same quarter of the previous year. Revenue, before royalties, and before gains or losses on financial instruments, for the nine months ended September 30, 2011, was \$163.7 million, a decrease of 3% compared to \$169.0 million in the same period of the previous year. Year to date, the decrease in revenue for 2011 was due to lower production volumes and lower realized gas prices, partially offset by higher realized oil prices.

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the three months ended September 30, 2011 was \$38.42 per BOE, an increase of 14% compared to the corresponding three month period of the previous year (\$33.73). The increased combined price received by the Company was primarily a result of higher average oil index prices during the quarter. WTI oil prices averaged US\$89.76 per barrel during the third quarter of 2011, compared to US\$76.20 per barrel in the same quarter of the previous year. AECO gas prices averaged \$3.47 per GJ during the third quarter of 2011, compared to \$3.36 per GJ in the third quarter of 2010.

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the nine months ended September 30, 2011 was \$38.26 per BOE, an increase of 5% compared to the corresponding nine month period of the previous year (\$36.61). During the nine month period ended September 30, 2011, WTI oil prices averaged US\$95.48 per barrel, compared to US\$77.65 per barrel in the same period of the previous year. AECO gas prices averaged \$3.57 per GJ, compared to \$3.91 per GJ in the first nine months of 2010.

## OIL OPERATIONS

Oil production for the third quarter ended September 30, 2011 averaged 3,859 barrels per day, an increase of 3% compared to 3,747 barrels per day in the same quarter of the previous year. Oil production for the nine months ended September 30, 2011 averaged 3,676 barrels per day, a decrease of 9% compared to 4,061 barrels per day in the same period of the previous year. The decrease in oil production in the first nine months of 2011 was primarily a result of non-core property dispositions and plant downtime resulting from outages at the KA and K3 Gas Plants.

The average price received for oil sales, after realized financial instruments, for the third quarter ended September 30, 2011 was \$79.77 (\$78.13 before financial instruments) per barrel, up 28% from the average price of \$62.29 (\$62.29 before financial instruments) per barrel received in the third quarter of 2010. The average price received for oil sales, after realized financial instruments, for the nine months ended September 30, 2011 was \$79.64 (\$81.02 before financial instruments) per barrel, up 18% from the average price of \$67.53 (\$67.53 before financial instruments) per barrel received in the first nine months of 2010.

The average Canadian dollar equivalent WTI crude oil index price was \$87.99 per barrel for the three months ended September 30, 2011 and \$93.38 per barrel nine months ended September 30, 2011. This represents an increase of 11% from \$79.21 per barrel for the three months ended September 30, 2010 and an increase of 16% from \$80.46 per barrel for the nine months ended September 30, 2010. During the first nine months of 2011, the average differential between the Canadian dollar equivalent WTI price and the Company's realized wellhead oil price, before financial instruments, was 13.4% compared to 16.1% in the same period of 2010.

For the quarter ended September 30, 2011, average oil royalties were 16.0% of revenue, after realized financial instruments (16.4% of revenue, before financial instruments). In the third quarter of the previous year, average oil royalties were 16.0% of revenue, after financial instruments (16.0% of revenue, before financial instruments). For the nine months ended September 30, 2011, average oil royalties were 16.8% of revenue, after realized financial instruments (16.5% of revenue, before financial instruments). In the first nine months of the previous year, average oil royalties were 17.6% of revenue, after financial instruments (17.6% of revenue, before financial instruments). Lower year-to-date oil royalty rates in 2011, before financial instruments, reflect the benefit of the royalty incentive programs offered by the Alberta government. For the three months ended September 30, 2011, the impact of higher realized oil prices more than offsets the benefits realized from these incentive programs, resulting in a higher oil royalty rate (before financial instruments).

Transportation expenses for oil production in the third quarter of 2011 averaged \$0.07 per barrel compared to \$0.11 per barrel in the third quarter of 2010. Transportation expenses for oil production for the nine months ended September 30, 2011 averaged \$0.13 per barrel compared to \$0.21 per barrel in the first nine months of 2010. Lower per unit transportation expenses in 2011 reflect the larger portion of newer NGL production which is mostly pipeline connected and therefore less expensive to transport compared to trucking oil.

For the third quarter ended September 30, 2011, oil production expenses were \$8.60 per barrel, compared to \$9.46 per barrel in the third quarter of 2010. For the nine months ended September 30, 2011, oil production expenses were \$8.73 per barrel, compared to \$10.73 per barrel in the first nine months of 2010. Lower per unit production expenses in the first nine months of 2011 reflect the larger portion of newer NGL production which is less expensive to produce compared to the Company's older oil production.

## **GAS OPERATIONS**

Gas production for the third quarter ended September 30, 2011 averaged 71,691 MCF per day, a decrease of 6% compared to 76,555 MCF per day in the corresponding quarter of the previous year. Gas production for the nine months ended September 30, 2011 averaged 71,177 MCF per day, a decrease of 10% compared to 79,294 MCF per day in the corresponding period of the previous year. Decreases in gas production in 2011 were primarily a result of non-core property dispositions and plant downtime resulting from outages at the KA and K3 Gas Plants.

The average price received for gas sales, after realized financial instruments, for the third quarter ended September 30, 2011 was \$4.18 (\$4.18 before financial instruments) per MCF, down 1% from the average price of \$4.22 (\$3.76 before financial instruments) per MCF received in the third quarter of 2010. The average price received for gas sales, after realized financial instruments, for the nine months ended September 30, 2011 was \$4.24 (\$4.24 before financial instruments) per MCF, down 6% from the average price of \$4.52 (\$4.35 before financial instruments) per MCF received in the first nine months of 2010.

The average AECO-C natural gas index price was \$3.47 per GJ (\$3.66 per MMBTU) for the three months ended September 30, 2011 and \$3.57 per GJ (\$3.76 per MMBTU) for the nine months ended September 30, 2011. This represents an increase of 3% from \$3.36 per GJ (\$3.54 per MMBTU) for the three months ended September 30, 2010 and a decrease of 9% from \$3.91 per GJ (\$4.12 per MMBTU) for the nine months ended September 30, 2010.

For the quarter ended September 30, 2011, average gas royalties were 6.9% of revenue, after financial instruments (6.9% of revenue, before financial instruments). In the third quarter of the previous year, average gas royalties were 4.5% of revenue, after financial instruments (5.0% of revenue, before financial instruments). For the nine months September 30, 2011, average gas royalties were 5.7% of revenue, after financial instruments (5.7% of revenue, before financial instruments). In the first nine months of the previous year, average gas royalties were 7.1% of revenue, after financial instruments (7.4% of revenue, before financial instruments). Lower year-to-date gas royalty rates in 2011, before financial instruments, are a result of the benefits of longer depth horizontal wells which receive favourable treatment under the Alberta royalty framework and new production qualifying for various incentive programs. In addition, royalties are impacted by gas cost allowance credits which do not fluctuate with gas prices.

Transportation expenses for the third quarter ended September 30, 2011 were \$0.08 per MCF, consistent with the same quarter of the previous year. Transportation expenses for the nine months ended September 30, 2011 were \$0.08 per MCF, down from \$0.09 per MCF in the same period in the previous year.

For the third quarter ended September 30, 2011, production expenses of \$1.29 per MCF were consistent with the corresponding quarter of the previous year. For the nine months ended September 30, 2011, production expenses of \$1.18 per MCF were 13% lower than \$1.35 per MCF in the corresponding period of the previous year. Production expenses in 2011 are lower as the Company continues to divest of its higher production cost properties and adds new production in its lower production cost properties.

#### **OTHER EXPENSES**

For the quarter ended September 30, 2011, financing expense was \$2.0 million (\$1.5 million including \$0.5 million of accretion on decommissioning obligations); general and administrative ("G&A") expenses were \$1.2 million (\$0.84 per BOE); and share based compensation expense was \$2.7 million; depletion, depreciation and amortization ("DD&A") expenses were \$34.8 million (\$23.92 per BOE), and asset expiries were \$0.7 million. In first nine months of 2011, financing expense was \$5.6 million (\$4.6 million including \$1.0 million of accretion on decommissioning obligations); G&A expenses were \$3.8 million (\$0.90 per BOE); and share based compensation expense was \$6.7 million; DD&A expenses were \$100.5 million (\$23.68 per BOE), and asset expiries were \$2.6 million.

In the previous year, for the quarter ended September 30, 2010, financing expense was \$1.2 million (\$1.4 million including \$0.2 million of accretion on decommissioning obligations); G&A expenses were \$1.0 million (\$0.67 per BOE); and share based compensation expense was \$1.3 million; DD&A expenses were \$31.0 million (\$20.40 per BOE), and asset expiries were \$0.8 million. In first nine months of 2010, financing expense was \$4.3 million (\$4.8 million including \$0.5 million of accretion on decommissioning obligations); G&A expenses were \$3.4 million (\$0.72 per BOE); and share based compensation expense was \$3.2 million; DD&A expenses were \$89.0 million (\$18.87 per BOE), and asset expiries were \$1.7 million.

Higher aggregate G&A expenses are a product of the Company's growth year over year. The Company has not capitalized any G&A expenses in 2011. In addition, lower production in the first nine months of 2011 contributed to the increase in G&A expressed on a per barrel basis. The increase in share based compensation reflects the appreciation of the Company's share price, which is a factor in the Black-Scholes option valuation model. Higher DD&A expense per BOE reflects the addition of proved reserves at higher than historic average costs. Asset expiries relate to the termination of mineral leases and a dry shallow gas property located in southern Alberta.

#### **TAXES**

For the quarter ended September 30, 2011, the Company provided for a provision of deferred income taxes in the amount of \$0.2 million, compared to a recovery of \$0.2 million in the third quarter of 2010. For the nine months ended September 30, 2011, the provision for deferred income taxes is \$2.0 million, compared to a provision of \$11.3 million in the same period of 2010.

For the three and nine month periods ended September 30, 2011, Celtic is not required to pay current income taxes as it has sufficient income tax deductions available to shelter taxable income for the period. Estimated income tax deductions available at September 30, 2011 are \$595.0 million.

### **PROFIT**

For the third quarter ended September 30, 2011, the Company incurred a loss of \$1.6 million (\$0.02 per common share, basic and diluted) compared to a loss of \$1.9 million (\$0.02 per common share, basic and diluted) in the third quarter of 2010. On a barrel of oil equivalent basis, the loss in the third quarter of 2011 was \$1.09 per BOE, compared to a loss of \$1.25 per BOE in the same quarter of 2010. During the third quarter of 2011, funds from operations were \$34.6 million (\$0.35 per common share basic and \$0.34 per common share diluted). In the same quarter of 2010, funds from operations were \$31.0 million (\$0.34 per common share, basic and diluted). On a barrel of oil equivalent basis, funds from operations in the third quarter of 2011 were \$23.81 per BOE, up 17% from \$20.39 per BOE in the same quarter of 2010.

Profit for the nine months ended September 30, 2011 was \$3.1 million (\$0.03 per common share, basic and diluted) compared to profit of \$27.4 million (\$0.31 per common share basic and \$0.30 per common share diluted) in the first nine months of 2010. On a barrel of oil equivalent basis, profit in the first nine months of 2011 was \$0.73 per BOE, compared to profit of \$5.82 per BOE in the same period of 2010. Funds from operations for the nine months ended September 30, 2011 were \$102.1 million (\$1.07 per common share basic and \$1.04 per common share diluted). In the same period of 2010, funds from operations were \$100.2 million (\$1.12 per common share basic and \$1.10 per common share diluted). On a barrel of oil equivalent basis, funds from operations in the first nine months of 2011 were \$24.07 per BOE, up 13% from \$21.24 per BOE in the same period of 2010.

Lower profit in 2011 reflects the decrease in production compared to 2010 and increased DD&A expense, which is partially offset by lower per unit production and transportation expenses. In addition, profit in 2010 was higher due to a gain on sale of assets in the amount of \$32.0 million, compared to a gain in 2011 of \$9.6 million.

### **CAPITAL EXPENDITURES**

During the quarter ended September 30, 2011, the Company spent \$96.4 million on capital projects. Drilling and completion operations accounted for \$69.8 million, equipment and facility expenditures were \$21.5 million and \$5.1 million was spent on land and seismic. Net capital expenditures, after drilling royalty credits, acquisitions and dispositions were \$96.7 million, up 33% from \$72.8 million in the third quarter of 2010.

During the nine months ended September 30, 2011, the Company spent \$252.5 million on capital projects. Drilling and completion operations accounted for \$179.6 million, equipment and facility expenditures were \$58.2 million and \$14.7 million was spent on land and seismic. Net capital expenditures, after drilling royalty credits, acquisitions and dispositions were \$237.4 million, up 114% from \$110.7 million in the same period of 2010.

At September 30, 2011, the Company had 710,513 gross (643,557 net) acres of undeveloped land. The Company continues to acquire land and build on its inventory of prospects for future drilling.

### **DRILLING ACTIVITY**

During the third quarter of 2011, the Company drilled 12 (7.5 net) wells, with an overall success rate of 91%. In the same quarter of 2010, the Company drilled 18 (12.7 net) wells, with an overall success rate of 100%. The average measured depth of net wells drilled in the third quarter of 2011 was 3,127 metres, a decrease of 4% compared to the average drilling measured depth of 3,250 metres in the third quarter of 2010.

During the nine months ended September 30, 2011, the Company drilled 46 (31.0 net) wells, with an overall success rate of 98%. In the same period of 2010, the Company drilled 47 (33.7 net) wells, with an overall success rate of 94%. The average measured depth of net wells drilled in the first nine months of 2011 was 3,675 metres, an increase of 5% compared to the average drilling measured depth of 3,486 metres in the same period of 2010.

## **CAPITAL RESOURCES AND LIQUIDITY**

### **SOURCE OF FUNDS**

Investment funding for capital expenditures incurred in the first nine months of 2011 was provided by proceeds from property dispositions, proceeds from the issue of common shares and by cash provided by operating activities.

On June 8, 2011 the Company extended its syndicated bank credit facility for a 364 day period commencing June 27, 2011. Under the terms of the extension, the borrowing base was increased from \$215.0 million to \$250.0 million. At September 30, 2011, Celtic had drawn \$165.0 million or 66% of its authorized borrowing amount, leaving sufficient unused credit lines available to fund on-going capital expenditures and working capital deficiencies. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

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

### **WORKING CAPITAL**

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At September 30, 2011, the working capital deficiency plus outstanding bank debt represented 88% of the Company's maximum authorized bank borrowing credit limit.

### **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 2009 and 2010, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. After falling into a recession, the global economy has commenced a recovery leading to an increase in demand for commodities and better access to capital. This economic recovery could be reversed if current debt issues facing Europe are not resolved in a satisfactory manner.

Celtic has good relationships with its syndicate of lenders. The Company's existing credit facility matures on June 27, 2012 and may be extended for an additional 364 days. The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

### **SHARE INFORMATION**

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. The Company's shareholders approved a two-for-one stock split effective May 6, 2010. All references to common shares and stock options in these financial statements are on a post stock split basis. As at September 30, 2011, there were 97.8 million common shares outstanding (as at November 9, 2011, there were 104.8 million common shares outstanding). There are no preferred shares outstanding.

As at September 30, 2011, directors, employees and certain consultants have been granted options to purchase 7.3 million common shares of the Company at an average exercise price of \$11.89 per common share.

The Company's common shares trade on the TSX under the symbol "CLT".

#### **FUTURE COMMITMENTS - DERIVATIVE 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 future oil sales swap contracts in effect as at September 30, 2011, that have fixed future sales prices based on the NYMEX WTI crude oil index, converted to Canadian dollars:

Daily Quantity	Remaining term of contract	Fixed price per barrel (bbl)
1,000 bbls/d	October 1 to December 31, 2011	\$ 90.00
1,000 bbls/d	October 1 to December 31, 2011	\$ 91.80

The following is a summary of interest rate swap contracts outstanding as at September 30, 2011, that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate:

Notional Amount	Remaining term of contract	Fixed interest rate (p.a.)
CA\$ 100,000,000	January 3, 2012 to December 31, 2012	0.88%

#### **CONTRACTUAL OBLIGATIONS**

Celtic has a committed term credit facility with certain financial institutions. The authorized borrowing amount under this facility as at September 30, 2011 was \$250.0 million, of which \$165.0 million was outstanding. Interest under this facility is payable monthly. Additional disclosure relating to bank debt is provided in the Notes to the financial statements.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provides employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems. As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers.

The Company is committed to future payments under the following agreements:

#### **CONTRACTUAL OBLIGATIONS**

(CA\$ thousands)	2011	2012	2013	2014	2015	2016	Total
Operating lease - office building	\$ 151	\$ 602	\$ 602	\$ 602	\$ 602	\$ 293	\$ 2,852
Operating lease - vehicles	53	137	94	28	-	-	312
<b>Total</b>	<b>\$ 204</b>	<b>\$ 739</b>	<b>\$ 696</b>	<b>\$ 630</b>	<b>\$ 602</b>	<b>\$ 293</b>	<b>\$ 3,164</b>

Office building operating lease relates to rental office space in Calgary, Alberta which expires on May 31, 2016.

## RELATED PARTY AND OFF-BALANCE SHEET TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the first nine months of 2011, the Company incurred \$0.4 million in costs with BLG (2010 - \$0.2 million). These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

Celtic was not involved in any off-balance sheet transactions in the periods ended September 30, 2010 and 2011.

## SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and daily average production through its drilling activities. The following tables summarize key financial and operating information by quarter for the past eight quarters (amounts for 2010 and 2011 were determined using IFRS and amounts for 2009 were determined using previous GAAP):

<i>(CA\$ thousands, except per unit amounts)</i>	<b>2011 Q3</b>	2011 Q2	2011 Q1	2010 Q4	<b>2010 Q3</b>	2010 Q2	2010 Q1	2009 Q4
Gross oil & gas revenue (\$)	<b>55,298</b>	54,733	53,652	53,041	<b>47,989</b>	57,202	63,809	60,146
Funds from operations (\$)	<b>34,626</b>	34,841	32,659	30,625	<b>30,963</b>	34,122	35,083	42,003
Per share - basic (\$/share)	<b>0.35</b>	0.36	0.36	0.34	<b>0.34</b>	0.38	0.39	0.47
Per share - diluted (\$/share)	<b>0.34</b>	0.35	0.34	0.33	<b>0.34</b>	0.37	0.39	0.46
Profit (loss) (\$)	<b>(1,592)</b>	4,020	672	(1,284)	<b>(1,897)</b>	3,236	26,110	906
Per share - basic (\$/share)	<b>(0.02)</b>	0.04	0.01	(0.01)	<b>(0.02)</b>	0.04	0.29	0.01
Per share - diluted (\$/share)	<b>(0.02)</b>	0.04	0.01	(0.01)	<b>(0.02)</b>	0.04	0.29	0.01
Total assets (\$)	<b>932,905</b>	868,214	818,492	750,346	<b>710,764</b>	678,587	677,010	678,770
Bank debt, net of								
working capital (\$)	<b>219,738</b>	161,636	147,879	203,381	<b>168,017</b>	124,901	126,366	168,417
Production (BOE/d)	<b>15,808</b>	15,203	15,605	17,385	<b>16,506</b>	18,029	17,302	17,274
Production per								
million shares (BOE/d)	<b>162</b>	157	171	192	<b>183</b>	201	194	194
Sales price, after								
derivatives (\$/BOE)	<b>38.42</b>	38.50	37.87	34.21	<b>33.73</b>	35.20	40.93	42.17
Operating netback (\$/BOE)	<b>25.68</b>	27.24	25.46	23.96	<b>22.08</b>	22.75	24.68	28.42
Netback as a percentage of sales	<b>67%</b>	71%	67%	70%	<b>65%</b>	65%	60%	67%

## SUBSEQUENT EVENTS

On October 7, 2011, Celtic issued 6.0 million common shares by way of a short form prospectus at an issue price of \$25.00 per common share for gross proceeds of \$150.0 million. In conjunction with this offering, the Company provided the syndicate of underwriters an over-allotment option to purchase an additional 0.9 million common shares at a price of \$25.00 per common share, which was exercised on October 25, 2011 providing incremental gross proceeds of \$22.5 million.

On November 1, 2011 the Company entered into an agreement with a major petroleum company to acquire natural gas assets at Grande Cache, Alberta, adjacent to Celtic's core area at Resthaven, for cash consideration of \$50.0 million, before closing adjustments. The acquisition has an effective date of July 1, 2011 and is subject to standard industry closing conditions. Closing is expected to occur during the second week of December 2011. The consideration to be paid by Celtic under the agreement will be

financed by bank debt. The Company has received an indication from its lead bank, National Bank of Canada, whereby Celtic's available bank credit lines will be increased by \$25.0 million to \$275.0 million, upon closing of the acquisition.

The assets are located in Alberta between townships 58 and 62 and ranges 6 to 10 west of the sixth meridian, directly west of Celtic's Resthaven lands. Recent natural gas production from the assets to be acquired was approximately 15.0 million cubic feet per day or 2,500 BOE per day, of which approximately 50% is operated. The acquisition also includes approximately 61,000 net acres (95 sections) of lands, of which approximately 33,000 net acres (51 sections) are undeveloped. The majority of the lands contain Cretaceous rights, including the Cardium, Dunvegan, Cadotte, Falher, Bluesky, Gething Cadomin and Nikanassin formations.

An independent reserve evaluation was prepared for the vendor by GLJ Petroleum Consultants Ltd. ("GLJ") effective March 31, 2011. In the report, GLJ assigned 4.7 million BOE of remaining proved producing reserves and 6.1 million BOE of remaining proved plus probable reserves. Average royalties are approximately 16% and production expenses are currently below \$6.00 per BOE.

In addition, the Company will acquire a 30.0% working interest in the Copton gas plant located at 11-25-059-09W6; a 7.0% working interest in the Narraway gas plant located at 10-08-062-10W6; and interests in various compressors and gas gathering pipelines.

The Company has identified several horizontal drilling opportunities on the Grande Cache asset base that have previously been developed using only vertical wells. The assets are complementary to Celtic's land holdings at Resthaven where the Company is drilling a horizontal well in the Cretaceous Falher formation.

## **BUSINESS RISKS**

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn

respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support on-going capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

#### **SAFETY AND ENVIRONMENT**

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

#### **CLIMATE CHANGE**

The Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business. The Alberta Government has set targets for GHG emission reductions. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund.

#### **BUSINESS OUTLOOK**

##### **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**

After the financial community around the world was rocked with unprecedented losses and business failures in 2009, the recovery that commenced in 2010 appears to be progressing, however, the current economic environment remains challenging and uncertain. Political upheaval in the Middle East remains a wild card and could hamper world economic recovery if oil supply is negatively affected. Inflation around the world could also have an impact on economic recovery which would ultimately affect the demand for energy in high growth countries such as India and China. Also, uncertainties facing debt markets in Europe could lead to tighter credit markets in the future.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby a portion of cash flow for 2011 has been secured to a certain extent through the use of oil price

derivative financial instruments. In addition, the Company accessed the equity market during the first nine months of the year adding financial strength to its balance sheet.

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

### **2011 GUIDANCE**

Celtic maintains its exit 2011 production guidance of approximately 24,500 BOE per day. However, due to the K3 Gas Plant outage and pipeline and facility construction delays, certain production at Fir and Resthaven were brought on-stream later than originally forecasted. As a result, average production for 2011 has been reduced to between 16,800 and 17,000 BOE per day (previously between 18,400 and 18,700 BOE per day).

The Company's average commodity price assumptions for 2011 are US\$92.50 (previously US\$93.50) per barrel for WTI oil, US\$4.15 (previously US\$4.30) per MMBTU for NYMEX natural gas, \$3.50 (previously \$3.55) per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$1.018 (previously US\$1.020). These prices compare to average 2010 prices of US\$79.43 per barrel for WTI oil, US\$4.42 per MMBTU for NYMEX natural gas, \$3.95 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.970.

After giving effect to the aforementioned production and commodity price assumptions, funds from operations for 2011 is forecasted to be approximately \$146.5 million or \$1.45 per common share, diluted (previous forecast was \$158.0 million or \$1.59 per common share, diluted) and net loss is forecasted to be approximately \$1.8 million or \$0.02 per common share, diluted (previous forecast was \$3.2 million or \$0.03 per common share, diluted).

Bank debt, net of working capital, is estimated to be \$82.9 million by the end of 2011 or approximately 0.6 times forecasted 2011 funds from operations.

The Company's announcement whereby it has entered into an agreement to acquire assets at Grande Cache, Alberta is not reflected in the guidance provided herein as that transaction is not expected to close until December 2011.

### **2012 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 the Company's 2012 capital expenditure budget of \$375.0 million. The Company expects to spend \$295.0 million on drilling and completing wells, \$60.0 million on facilities, equipment and pipelines, and \$20.0 million on land and seismic.

Celtic expects production in 2012 to average between 27,500 and 28,000 BOE per day. The Company recently added significant production at Resthaven and Fir after installing gas gathering pipelines and compression and dehydration facilities and looks forward to continued growth from both these areas in 2012. Average production in 2012 is expected to be weighted 24% oil and 76% gas; however, operating income in 2012 is expected to be weighted 52% oil and 48% gas. At the low end of the range of 2012's average production forecast, this represents a 64% increase from the forecasted average production of 16,800 BOE per day for 2011. On a production per share basis, the increase would be 53%.

Celtic expects to achieve continued efficiencies in its cost structure in 2012. Production expense is estimated to be \$7.57 per BOE and royalties are expected to average 10.9%. General and administrative expense is estimated to be at industry leading low levels of \$0.67 per BOE.

The Company's average commodity price assumptions for 2012 are US\$82.50 per barrel for WTI oil, US\$4.15 per MMBTU for NYMEX natural gas, \$3.65 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$0.9755. These prices compare to forecasted average 2011 prices of US\$92.50 per barrel for WTI oil, US\$4.15 per MMBTU for NYMEX natural gas, \$3.50 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US\$1.018.

After giving effect to the aforementioned production and commodity price assumptions, funds from operations for 2012 is forecasted to be approximately \$243.0 million or \$2.22 per common share, diluted and net loss is forecasted to be approximately \$10.0 million or \$0.10 per common share, diluted.

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

Sensitivities to changes in commodity prices would affect forecasted 2012 funds from operations and profit as follows:

- (i) A change of 10% in AECO natural gas price of \$0.365 per GJ would affect funds from operations by \$17.2 million (\$0.15 per common share) and profit by \$12.9 million (\$0.12 per common share);
- (ii) A change of 10% in WTI oil price of US\$8.25 per barrel would affect funds from operations by \$6.9 million (\$0.06 per common share) and profit by \$5.2 million (\$0.05 per common share); and
- (iii) A change of 10% in US/Canadian dollar exchange rate of US\$0.0976 per CAD would affect funds from operations by \$34.5 million (\$0.31 per common share) and profit by \$25.8 million (\$0.23 per common share).

Bank debt, net of working capital, is estimated to be \$215.0 million by the end of 2012 or approximately 0.9 times forecasted 2012 funds from operations.

Upon closing of the previously announced agreement to acquire assets at Grande Cache, Alberta, the Company will provide revised 2012 guidance to reflect the impact of the acquisition.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per common 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 2012 and beyond.

The information set out herein under the heading "2011 Guidance" and "2012 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 2011 and 2012. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

**ADDITIONAL INFORMATION**

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at [www.sedar.com](http://www.sedar.com). Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 600, 321 Sixth Avenue SW, Calgary, Alberta, Canada, T2P 3H3. Further information relating to the Company is also available on its website at [www.celticex.com](http://www.celticex.com).

On behalf of the Board of Directors,

A handwritten signature in black ink, appearing to read 'D. J. Wilson', written in a cursive style.

**David J. Wilson**

President and Chief Executive Officer

November 9, 2011

# INTERIM FINANCIAL STATEMENTS

## STATEMENT OF FINANCIAL POSITION

[Unaudited]

(CA\$ thousands)	[Notes]	As at September 30, 2011	As at December 31, 2010
			[Note 18]
<b>ASSETS</b>			
<b>Current assets</b>			
Cash and cash equivalents		509	644
Accounts receivable		36,665	41,535
Drilling royalty credits	[5]	-	2,906
Prepaid expenses and deposits		6,083	4,871
Derivative financial instruments	[13]	1,700	-
<b>Total current assets</b>		<b>44,957</b>	49,956
Deferred income tax asset		-	698
Other assets		9,259	5,800
Exploration and evaluation assets	[3]	80,979	67,822
Property, plant and equipment	[4]	797,710	626,070
<b>Total assets</b>		<b>932,905</b>	750,346
<b>LIABILITIES</b>			
<b>Current liabilities</b>			
Accounts payable and accrued liabilities		99,615	89,904
Derivative financial instruments	[13]	80	2,633
Bank debt	[6]	165,000	160,800
<b>Total current liabilities</b>		<b>264,695</b>	253,337
Derivative financial instruments	[13]	20	-
Decommissioning obligations	[7]	65,819	25,759
Deferred income tax liability		54,785	54,843
<b>Total liabilities</b>		<b>385,319</b>	333,939
<b>SHAREHOLDERS' EQUITY</b>			
Shareholders' capital	[8]	419,179	296,065
Contributed surplus		14,414	9,449
Retained earnings		113,993	110,893
<b>Total shareholders' equity</b>		<b>547,586</b>	416,407
<b>Total liabilities and shareholders' equity</b>		<b>932,905</b>	750,346
Commitments	[12]		
Subsequent events	[17]		

The accompanying notes form an integral part of these condensed interim financial statements.

On behalf of the Board of Directors:



Director



Director

## STATEMENT OF PROFIT (LOSS) AND COMPREHENSIVE INCOME (LOSS)

[Unaudited]

<i>(CA\$ thousands, except per share amounts)</i>	[Notes]	Three months ended September 30, <b>2011</b>	2010	Nine months ended September 30, <b>2011</b>	2010
			[Note 18]		[Note 18]
<b>Revenue</b>					
Oil and gas		<b>55,298</b>	47,989	<b>163,723</b>	169,000
Royalties		<b>(6,471)</b>	(4,770)	<b>(18,044)</b>	(20,121)
		<b>48,827</b>	43,219	<b>145,679</b>	148,879
<b>Expenses</b>					
Production		<b>11,540</b>	12,327	<b>31,749</b>	41,057
Transportation		<b>522</b>	601	<b>1,746</b>	2,236
Financing	[15]	<b>2,018</b>	1,420	<b>5,603</b>	4,826
General and administrative		<b>1,227</b>	1,014	<b>3,814</b>	3,403
Share based compensation	[8]	<b>2,687</b>	1,312	<b>6,691</b>	3,246
Depletion, depreciation and amortization		<b>34,789</b>	30,977	<b>100,473</b>	88,988
Asset expiries	[3]	<b>694</b>	846	<b>2,647</b>	1,694
		<b>53,477</b>	48,497	<b>152,723</b>	145,450
<b>Profit (loss) before other items and income taxes</b>					
		<b>(4,650)</b>	(5,278)	<b>(7,044)</b>	3,429
Gain on derivative financial instruments	[9]	<b>3,407</b>	223	<b>2,585</b>	3,264
Gain (loss) on sale of assets		<b>(195)</b>	2,966	<b>9,550</b>	32,036
<b>Profit (loss) before income taxes</b>					
		<b>(1,438)</b>	(2,089)	<b>5,091</b>	38,729
Deferred income tax expense (recovery)	[10]	<b>154</b>	(192)	<b>1,991</b>	11,280
<b>Profit (loss) and comprehensive income (loss)</b>					
		<b>(1,592)</b>	(1,897)	<b>3,100</b>	27,449
<b>Profit (loss) per common share</b>					
Basic	[11]	<b>\$ (0.02)</b>	\$ (0.02)	<b>\$ 0.03</b>	\$ 0.31
Diluted	[11]	<b>\$ (0.02)</b>	\$ (0.02)	<b>\$ 0.03</b>	\$ 0.30

The accompanying notes form an integral part of these condensed interim financial statements.

## STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

[Unaudited]

<i>(CA\$ thousands)</i>	[Notes]	Shareholders' capital	Contributed surplus	Retained earnings	Total shareholders' equity
Balance, December 31, 2010		<b>296,065</b>	<b>9,449</b>	<b>110,893</b>	<b>416,407</b>
Profit				<b>3,100</b>	<b>3,100</b>
Issue of shares, net of issue costs	[8]	<b>112,878</b>			<b>112,878</b>
Issue of shares on exercise of stock options	[8]	<b>8,510</b>			<b>8,510</b>
Share based compensation	[8]		<b>6,691</b>		<b>6,691</b>
Share based compensation settlements	[8]	<b>1,726</b>	<b>(1,726)</b>		<b>-</b>
<b>Balance, September 30, 2011</b>		<b>419,179</b>	<b>14,414</b>	<b>113,993</b>	<b>547,586</b>
Balance, January 1, 2010		282,990	6,798	84,728	374,516
Profit				27,449	27,449
Issue of shares, net of issue costs	[8]				-
Issue of shares on exercise of stock options	[8]	6,493			6,493
Share based compensation	[8]		3,246		3,246
Share based compensation settlements	[8]	1,206	(1,206)		-
Balance, September 30, 2010	[18]	290,689	8,838	112,177	411,704

The accompanying notes form an integral part of these condensed interim financial statements.

## STATEMENT OF CASH FLOWS

[Unaudited]

(CA\$ thousands)	[Notes]	Three months ended September 30,		Nine months ended September 30,	
		2011	2010	2011	2010
			[Note 18]		[Note 18]
<b>Operating activities</b>					
Profit (loss)		(1,592)	(1,897)	3,100	27,449
Items not affecting cash:					
Depletion, depreciation and amortization		34,789	30,977	100,473	88,988
Accretion of decommissioning obligations		525	179	1,007	558
Asset expiries		694	846	2,647	1,694
Share based compensation		2,687	1,312	6,691	3,246
Unrealized (gain) loss on derivative financial instruments	[9]	(2,826)	2,704	(4,233)	(1,011)
Loss (gain) on sale of assets		195	(2,966)	(9,550)	(32,036)
Deferred income tax expense (recovery)		154	(192)	1,991	11,280
Settlement of decommissioning obligations	[7]	(1,896)	-	(1,915)	-
Change in non-cash operating working capital	[14]	(3,984)	9,422	(11,988)	16,590
<b>Cash provided by operating activities</b>		<b>28,746</b>	40,385	<b>88,223</b>	116,758
<b>Financing activities</b>					
Increase (decrease) in bank debt		35,000	21,600	4,200	(20,700)
Issue of common shares, net of costs	[8]	2,693	1,983	120,037	6,492
<b>Cash provided by (used in) financing activities</b>		<b>37,693</b>	23,583	<b>124,237</b>	(14,208)
<b>Investing activities</b>					
Property, plant and equipment expenditures		(88,824)	(47,590)	(236,888)	(128,491)
Property, plant and equipment acquisitions		-	(7,730)	(59)	(7,713)
Property, plant and equipment dispositions		(195)	2,840	16,177	49,831
Exploration and evaluation asset expenditures		(7,663)	(20,282)	(17,237)	(24,351)
Exploration and evaluation asset dispositions		-	306	609	6,124
Change in other assets		312	(902)	(3,460)	(2,586)
Change in non-cash investing working capital	[14]	29,930	9,372	28,263	4,638
<b>Cash used in investing activities</b>		<b>(66,440)</b>	(63,986)	<b>(212,595)</b>	(102,548)
<b>Net change in cash and cash equivalents</b>		<b>(1)</b>	(18)	<b>(135)</b>	2
<b>Cash and cash equivalents, beginning of period</b>		<b>510</b>	62	<b>644</b>	42
<b>Cash and cash equivalents, end of period</b>		<b>509</b>	44	<b>509</b>	44

The accompanying notes form an integral part of these condensed interim financial statements.

# NOTES TO THE INTERIM FINANCIAL STATEMENTS

**For the interim periods ended September 30, 2011 and September 30, 2010**  
**(All tabular amounts in thousands of Canadian dollars, unless otherwise stated)**

## **1. REPORTING ENTITY AND PRESENTATION OF FINANCIAL STATEMENTS**

### **NATURE OF BUSINESS**

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the Business Corporations Act (Alberta) on April 16, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta. The Company's head office is located at 321 - 6th Avenue SW, Suite 600, Calgary, Alberta, T2P 3H3.

### **BASIS OF PRESENTATION**

The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. In these financial statements, the term "previous GAAP" refers to Canadian GAAP before the adoption of IFRS.

These condensed interim financial statements have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting" and IFRS 1 "First-time Adoption of International Financial Reporting Standards". Accordingly, these condensed interim financial statements do not include all of the information required for full annual financial statements. The impact of IFRS on the Company's previously reported financial statements for the year ended December 31, 2010 and opening balance sheet as at January 1, 2010 is disclosed in the Company's unaudited interim financial statements for the period ended March 31, 2011. Subject to certain transitional elections disclosed in Note 18, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect. A summary of significant adjustments to shareholders' equity as at September 30, 2010 and to comprehensive income for the three and nine months ended September 30, 2010, is presented in Note 18.

The policies applied in these condensed interim financial statements are based on IFRS issued as of November 9, 2011, the date the statements were authorized for issuance by the Company's Board of Directors. Any subsequent changes to IFRS that are given effect in the Company's annual financial statements for the year ending December 31, 2011 could result in restatement of these condensed interim financial statements, including the transitional adjustments recognized on change over to IFRS.

The condensed interim financial statements should be read in conjunction with the Company's Canadian GAAP annual financial statements for the year ended December 31, 2010.

### **BASIS OF MEASUREMENT**

All references to dollar amounts in these financial statements and related Notes are Canadian dollars, unless otherwise indicated.

These financial statements have been prepared on a historical cost basis, except for certain derivative financial instruments and other financial assets which are carried at fair value. The methods used to measure fair values are discussed in Note 13.

### **JOINT INTERESTS**

A substantial portion of the Company's exploration, development and production activities is conducted jointly with others through unincorporated joint ventures. These financial statements reflect only the Company's proportionate interest of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

## **SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS**

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates and affect the results reported in these interim financial statements and could be material. Estimates and underlying assumptions are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

### **Judgments**

In the process of applying Celtic's accounting policies, judgments, apart from those involving estimates, have been made.

The following are judgments that may have the most significant effect on the amounts recognized in the financial statements:

### **Reserves**

Oil and gas assets are depreciated on a unit of production basis at a rate calculated by reference to proved reserves determined in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and incorporating the estimated future cost of developing and extracting those reserves. Proved reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is ninety percent likely that the actual remaining quantities recovered will exceed the estimated proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved reserves. The level of estimated reserves is also a key determinant in assessing whether the carrying value of the Company's petroleum and natural gas assets may be impaired.

### **Impairment of non-financial assets**

Impairment of property, plant and equipment ("PP&E") and exploration and evaluation assets ("E&E") is evaluated at the cash-generating unit ("CGU") level. The determination of CGU's requires judgment in defining the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGU's have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type and similar exposures to market risks.

The recoverable amount of the Company's CGU's is determined based on the greater of the value-in-use and fair value less costs to sell. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates and other relevant assumptions.

### **Technical feasibility and commercial viability of exploration and evaluation assets**

The determination of technical feasibility and commercial viability, based on the presence of proved and probable reserves, results in the transfer of assets from E&E to PP&E. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgment. Therefore, any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

### **Valuation of derivative financial instruments**

By their very nature, the estimated fair value of derivative financial contracts resulting in derivative financial assets and liabilities are subject to measurement uncertainty.

### **Measurement of share-based compensation**

Measurement of compensation cost attributable to the Company's share based compensation plan is subject to the estimation of fair value using the Black-Scholes option pricing model. The valuation is based on significant assumptions such as: i) the volatility of the share price; ii) the life of the option; iii) the risk-free interest rate for the life of the option; and iv) the number of options that will ultimately vest.

### **Decommissioning costs**

The Company estimates the decommissioning obligations for oil and natural gas wells as well as their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. The value of the ultimate decommissioning obligation can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, and changes to the risk-free discount rate. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

### **Income taxes**

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flows, and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

The Company recognizes the net future tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods.

### **Contingencies**

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur.

The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

### **MEASUREMENT UNCERTAINTY**

The amounts recorded for the fair value of derivative financial instruments, share based compensation, depletion, depreciation and accretion of assets, the provision for asset decommissioning obligations and the provision for deferred income taxes are based on estimates. In addition, the impairment test calculation is based on estimates of reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

## **2. SIGNIFICANT ACCOUNTING POLICIES**

These condensed interim financial statements have been prepared following the same accounting policies and methods of computation as the interim financial statements as at March 31, 2011. The significant accounting policies are described in Note 2 of the March 31, 2011 interim financial statements.

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

The IASB has issued the following standards which have not yet been adopted by the Company: IFRS 9, Financial Instruments, IFRS 10, Consolidated Financial Statements, IFRS 11, Joint Arrangements, IFRS 12, Disclosure of Interests in Other Entities, IAS 27, Separate Financial Statements, IFRS 13, Fair Value Measurement and Amended IAS 28, Investments in Associates and Joint Ventures. Also, the IASB has amended IAS 19, Employee Benefits, which has not yet been adopted by the Company. Each of the new standards is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company has performed a preliminary assessment of the impact of the new and amended standards and does not currently expect that the adoption of these standards will have a significant impact on the Company's financial statements.

The following is a brief summary of the new and amended standards:

IFRS 9 is the first step to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39.

IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 Consolidation – Special Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements.

IFRS 11 requires an entity to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the entity will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities – Non-monetary Contributions by Venturers. IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities.

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

IAS 19 has been amended to make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. A number of other amendments have been made to recognition, measurement and classification including redefining short-term and other long-term benefits, guidance on the treatment of taxes related to benefit plans, guidance on risk/cost sharing features, and expanded disclosures.

In addition, there have been amendments to existing standards, including IAS 27, Separate Financial Statements, and IAS 28, Investments in Associates and Joint Ventures. IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 - 13.

### **3. EXPLORATION AND EVALUATION ASSETS**

	<b>September 30, 2011</b>	December 31, 2010
Exploration and evaluation assets, at cost	<b>\$ 82,827</b>	\$ 70,080
Expiries	<b>(1,848)</b>	(2,258)
Net carrying amount	<b>\$ 80,979</b>	\$ 67,822

The following table reconciles movements of exploration and evaluation assets during the period:

	<b>September 30, 2011</b>	December 31, 2010
Net carrying amount, beginning of period	<b>\$ 67,822</b>	\$ 39,014
Additions	<b>17,237</b>	37,190
Dispositions	<b>(609)</b>	(6,124)
Transfers to PP&E	<b>(1,623)</b>	-
Expiries	<b>(1,848)</b>	(2,258)
Net carrying amount, end of period	<b>\$ 80,979</b>	\$ 67,822

Exploration and evaluation assets consist of the Company's undeveloped land and exploration projects which are pending the determination of technical feasibility and commercial viability.

#### 4. PROPERTY, PLANT AND EQUIPMENT

	September 30, 2011	December 31, 2010
Development and production assets, at cost	<b>\$ 1,346,539</b>	\$ 1,083,364
Corporate assets, at cost	<b>2,631</b>	2,294
Property, plant and equipment, at cost	<b>\$ 1,349,170</b>	\$ 1,085,658
Accumulated depletion, depreciation and amortization	<b>(551,460)</b>	(459,588)
Net carrying amount	<b>\$ 797,710</b>	\$ 626,070

The following table reconciles movements of property, plant and equipment during the period:

	D&P <sup>(1)</sup> Assets	Corporate Assets	Total PP&E
Property, plant and equipment, at cost			
Balance at January 1, 2010	\$ 914,660	\$ 1,743	\$ 916,403
Additions	200,872	551	201,423
Transfers from E&E	-	-	-
Acquisitions	7,883	-	7,883
Disposals	(40,051)	-	(40,051)
Balance at December 31, 2010	\$ 1,083,364	\$ 2,294	\$ 1,085,658
Additions	279,499	363	279,862
Transfers from E&E	1,623	-	1,623
Acquisitions	-	-	-
Disposals	(17,947)	(26)	(17,973)
<b>Balance at September 30, 2011</b>	<b>\$ 1,346,539</b>	<b>\$ 2,631</b>	<b>\$ 1,349,170</b>

	D&P <sup>(1)</sup> Assets	Corporate Assets	Total PP&E
Accumulated depletion, depreciation and amortization			
Balance at January 1, 2010	\$ 353,569	\$ 908	\$ 354,477
Depletion, depreciation and amortization	117,518	260	117,778
Impairment charges, net of reversals	2,368	-	2,368
Disposals	(15,035)	-	(15,035)
Balance at December 31, 2010	\$ 458,420	\$ 1,168	\$ 459,588
Depletion, depreciation and amortization	99,412	1,061	100,473
Impairment charges, net of reversals	-	-	-
Disposals	(8,575)	(26)	(8,601)
<b>Balance at September 30, 2011</b>	<b>\$ 549,257</b>	<b>\$ 2,203</b>	<b>\$ 551,460</b>

(1) Development and production assets have been abbreviated as "D&P assets"

Future capital costs required to develop proved reserves in the amount of \$135.3 million (2010 - \$105.9 million) are included in the depletion and depreciation calculation.

## 5. DRILLING ROYALTY CREDITS

The Drilling Royalty Credit ("DRC") program introduced by the Alberta government in 2009 provided companies with a \$200 per metre credit on wells drilled. These credits can be applied against corporate Crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% of corporate Crown royalties for Celtic. Credits earned are recorded as a reduction of property, plant and equipment, with reasonable assurance that credits can be claimed in a future period.

The following table reconciles movements of drilling royalty credits during the period:

	September 30, 2011	December 31, 2010
Drilling royalty credits, beginning of period	\$ 2,906	\$ 13,158
Credits earned through drilling	8,600	30,582
Credits claimed	(2,034)	(11,533)
Credits deemed un-claimable	(9,472)	(29,301)
Drilling royalty credits, end of period	\$ -	\$ 2,906

## 6. BANK DEBT

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at September 30, 2011 is \$250.0 million. The facilities are available for a period of 364 days, maturing on June 27, 2012 and may be extended for an additional 364 days. 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. As at September 30, 2011, the Company is in compliance with all covenants. 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.

The following table summarizes bank debt outstanding:

	September 30, 2011	December 31, 2010
Bank loan	\$ 65,000	\$ 30,800
Bankers' acceptances	100,000	130,000
Bank debt	\$ 165,000	\$ 160,800

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.00% to bank prime plus 2.50%, 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 2.00% to 3.50%, 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.

## 7. DECOMMISSIONING OBLIGATIONS

Decommissioning obligations arise as a result of the Company's net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	September 30, 2011	December 31, 2010
Decommissioning obligations, beginning of period	\$ 25,759	\$ 21,151
Obligations incurred	5,052	4,363
Obligations disposed	(2,737)	(2,347)
Obligations settled	(1,915)	(1,897)
Revisions to estimated obligations	38,653	3,736
Accretion expense	1,007	753
Decommissioning obligations, end of period	\$ 65,819	\$ 25,759

The key assumptions, on which the carrying amount of the decommissioning obligations is based, include an average risk-free rate of 2.7% (2010 - 3.9%) and an inflation rate of 2.0% (2010 - 2.7%). The total undiscounted amount of the estimated cash flows required to settle the obligations is \$80.1 million (December 31, 2010 - \$33.2 million) which will be incurred over the next 50 years, with the majority of costs expected to be settled between 2035 and 2055.

The Company recorded a significant revision to estimated decommissioning obligations in the period. The increase in the present value of future decommissioning obligations is due to a combination of discounting future cost estimates at a lower rate than in prior periods, and increasing the underlying cost estimates. In prior periods, the Company estimated abandonment and reclamation costs using publicly available industry data as a benchmark. In the current year, an external party was engaged to perform an independent review of the Company's operating locations and provided new information with respect to the estimated costs of future site restoration. The change in estimate has been recognized prospectively by increasing the carrying amount of the decommissioning obligation, with a corresponding addition to the carrying amount of the development and production assets to which the obligations relate.

Accretion of the decommissioning obligation due to the passage of time is presented within financing expenses in the statement of profit (loss) and comprehensive income (loss) (see Note 15).

## **8. SHARE CAPITAL**

### **(a) Authorized**

Unlimited number of common shares and preferred shares.

### **(b) Issued**

The following table summarizes the changes in common shares outstanding:

	Common shares (000's)	Amount
Balance, December 31, 2009	89,125	\$ 282,990
Issued for cash on exercise of stock options	1,751	11,060
Amount relating to exercised options previously recorded as contributed surplus	-	2,015
Balance, December 31, 2010	90,876	\$ 296,065
Issued for cash on exercise of stock options	1,194	8,510
Amount relating to exercised options previously recorded as contributed surplus	-	1,726
Issued for cash through public prospectus offering	5,750	116,725
Share issue costs, after deferred income taxes	-	(3,847)
<b>Balance, September 30, 2011</b>	<b>97,820</b>	<b>\$ 419,179</b>

There are no preferred shares issued or outstanding as of September 30, 2011 (2010 - nil).

### **(c) Common share offerings**

In March 2011, Celtic issued 5.0 million common shares by way of a short form prospectus at an issue price of \$20.30 per common share for gross proceeds of \$101.5 million. In conjunction with this offering, the Company provided the syndicate of underwriters an over-allotment option to purchase an additional 0.75 million common shares at a price of \$20.30 per common share, which was exercised in April 2011 providing gross proceeds of \$15.2 million.

### **(d) Stock options**

Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and certain consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange at the time of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding:

	Number of options (000's)	Average exercise price
Balance, December 31, 2009	6,616	\$ 6.95
Granted	2,049	10.70
Exercised	(1,751)	6.32
Forfeited/expired	(365)	6.97
Balance, December 31 2010	6,549	\$ 8.31
Granted	2,029	20.64
Exercised	(1,194)	7.13
Forfeited/expired	(47)	11.46
<b>Balance, September 30, 2011</b>	<b>7,337</b>	<b>\$ 11.89</b>

The Company uses the fair value method to record stock based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for new grants as follows:

	Nine months ended September 30, 2011	Twelve months ended December 31, 2010
Risk free interest rate	2.10%	1.95%
Expected life (years)	3.8	3.1
Expected volatility	43%	43%
Expected dividend yield	-	-
Expected forfeiture rate	5%	5%
Fair value of options granted during the year (\$/share)	\$ 6.75	\$ 3.35

The following table summarizes information regarding stock options outstanding at September 30, 2011:

Range of exercise prices per common share	Number of options outstanding (000's)	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable (000's)	Weighted average exercise price per share for options exercisable
\$5.00 to \$8.50	2,379	1.8	\$ 6.70	1,826	\$ 6.66
\$8.51 to \$12.00	2,825	2.9	\$ 9.90	1,454	\$ 9.33
\$12.01 to \$15.50	55	3.9	\$ 12.58	8	\$ 12.65
\$15.51 to \$19.00	55	4.2	\$ 16.18	-	-
\$19.01 to \$22.50	2,023	4.6	\$ 20.64	-	-
<b>Total</b>	<b>7,337</b>	<b>3.1</b>	<b>\$ 11.89</b>	<b>3,288</b>	<b>\$ 7.86</b>

## 9. RISK MANAGEMENT CONTRACTS

Derivative financial instruments are used as a means of managing commodity price and interest rate volatility. Refer to Note 13 for further discussion of the Company's risk management practices. The following table reconciles realized and unrealized gains (losses) on derivative financial instruments to the amounts reported in the statement of profit (loss) and comprehensive income (loss):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Realized gain (loss)	\$ 581	\$ 2,927	\$ (1,648)	\$ 2,253
Unrealized gain (loss)	2,826	(2,704)	4,233	1,011
Gain on derivative financial instruments	\$ 3,407	\$ 223	\$ 2,585	\$ 3,264

## 10. INCOME TAXES

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate as a result of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Profit (loss) before taxes	\$ (1,438)	\$ (2,089)	\$ 5,091	\$ 38,729
Statutory combined federal & provincial income tax rate	26.50%	28.00%	26.50%	28.00%
Expected income tax expense (recovery)	\$ (381)	\$ (585)	\$ 1,349	\$ 10,844
Increase (decrease) resulting from:				
Non-deductible share based compensation expense	712	367	1,773	909
Other adjustments	(177)	26	(1,131)	(473)
Provision for deferred income tax expense (recovery)	\$ 154	\$ (192)	\$ 1,991	\$ 11,280

## 11. PROFIT (LOSS) PER COMMON SHARE

The table below summarizes the weighted average number of common shares outstanding:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Weighted average common shares outstanding, basic	97,650	90,089	95,402	89,701
Effect of stock options	3,250	2,021	3,100	1,438
Weighted average common shares outstanding, diluted	100,900	92,110	98,502	91,139

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted profit per common share.

In computing the diluted loss per common share for the three month periods ended September 30, 2011 and September 30, 2010, the Company excluded the effect of stock options as they were anti-dilutive.

## 12. COMMITMENTS

The Company is committed to future payments under the following agreements:

(CA\$ thousands)	2011	2012	2013	2014	2015	2016	Total
Operating lease - office building	\$ 151	\$ 602	\$ 602	\$ 602	\$ 602	\$ 293	\$ 2,852
Operating lease - vehicles	53	137	94	28	-	-	312
<b>Total</b>	<b>\$ 204</b>	<b>\$ 739</b>	<b>\$ 696</b>	<b>\$ 630</b>	<b>\$ 602</b>	<b>\$ 293</b>	<b>\$ 3,164</b>

Office building operating lease relates to rental office space in Calgary, Alberta. The current lease expires on May 31, 2016.

At September 30, 2011, the Company had bank debt outstanding in the amount of \$165.0 million. The Company has a \$250.0 million term credit facility that is available on a revolving basis until June 27, 2012.

## 13. FINANCIAL INSTRUMENTS

### (a) Fair values of financial assets and liabilities

Financial assets and liabilities of the Company consist mainly of cash and cash equivalents, deposits, drilling royalty credits, receivables, payables, bank debt and assets and liabilities arising from the use of financial instrument risk management contracts, all of which are included in these financial statements.

Celtic's financial risk management contracts are transacted in active markets. The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Celtic's derivative financial instruments are classified as Level 2 Inputs. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

The following table presents the Company's fair value measurements for each hierarchy level as at September 30, 2011:

	Level 1 inputs	Level 2 inputs	Level 3 inputs	Total
Crude oil swaps	-	\$ 1,700	-	\$ 1,700
Interest rate swaps	-	(100)	-	(100)
Net asset (liability)	-	\$ 1,600	-	\$ 1,600

At September 30, 2011, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying amount	Fair value
Loans and receivables		
(cash, accounts receivable, drilling royalty credits and deposits)	\$ 42,260	\$ 42,260
Held-for-trading instruments (derivative financial instruments)	(1,600)	(1,600)
Other financial liabilities (accounts payable and bank debt)	(264,615)	(264,615)
<b>Total, as of September 30, 2011</b>	<b>\$ (223,955)</b>	<b>\$ (223,955)</b>

At December 31, 2010, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying amount	Fair value
Loans and receivables		
(cash, accounts receivable, drilling royalty credits and deposits)	\$ 49,294	\$ 49,294
Held-for-trading instruments (derivative financial instruments)	(2,633)	(2,633)
Other financial liabilities (accounts payable and bank debt)	(250,704)	(250,704)
<b>Total, as of December 31, 2010</b>	<b>\$ (204,043)</b>	<b>\$ (204,043)</b>

#### (b) Credit risk

The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk.

The aging of the Company's accounts receivable is summarized in the following table:

	Current	31 – 60 days	61 – 90 days	Over 90 days	Total
<b>September 30, 2011</b>					
<b>Accounts receivable</b>	<b>\$ 31,436</b>	<b>\$ 805</b>	<b>\$ 1,519</b>	<b>\$ 2,905</b>	<b>\$ 36,665</b>
December 31, 2010					
Accounts receivable	\$ 34,437	\$ 2,034	\$ 648	\$ 4,416	\$ 41,535

Celtic has not experienced any material credit loss in the collection of receivables in 2011 and 2010.

#### (c) Interest rate risk

The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed rate borrowings using bankers' acceptances and interest rate swap transactions.

The Company entered into an interest rate swap transaction whereby the interest rate applicable to a notional \$100.0 million of borrowings by way of bankers' acceptances is fixed at an annual interest rate of 0.88% (before bank stamping fees). The contract is effective commencing January 3, 2012 and matures on December 31, 2012.

**(d) Foreign exchange rate risk**

The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

In order to mitigate a portion of the risk relating to revenue that is subject to fluctuations in the exchange rate, the Company has entered into commodity swap transactions whereby commodity prices denominated in U.S. dollars have been converted to Canadian dollars as described under the heading "Commodity price risk management" below.

**(e) Commodity price risk management**

Inherent to the business of producing oil and gas, the Company's cash provided by operating activities is subject to commodity price risk. Fluctuations in the market price of crude oil, natural gas and natural gas liquids impact the Company's liquidity given that the level of capital expenditures and debt repayments or draw-downs are driven by cash provided by operating activities.

The following is a summary of NYMEX West Texas Intermediate ("WTI") light sweet oil fixed price contracts in effect at September 30, 2011:

Daily quantity	Remaining term of contract	Fixed price per bbl
2,000 bbls per day	October 1 to December 31, 2011	CA\$ 90.90

The fair value of the remaining term of the above crude oil contracts, mark-to-market at September 30, 2011 is an asset of \$1.7 million. If the Canadian dollar equivalent WTI price increases (decreases) by \$1.00 per bbl, the fair market value of these contracts would increase (decrease) by \$184,000.

**(f) Liquidity risk**

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.

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

Celtic has a committed credit facility which matures on June 27, 2012 and may be extended for an additional 364 days with the consent of the lenders. Although management expects that the financial institutions will extend the facility in 2012, there can be no assurance that the financial institutions will choose to do so. Should the financial institutions not extend the loan, the Company would need to seek alternative sources of debt or equity financing or dispose of certain assets to repay the outstanding indebtedness.

### (g) Capital structure

The Company's capital structure is comprised of shareholders' equity, bank debt and working capital. Celtic's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing funds from operations ratio, a non-IFRS financial measure.

	September 30, 2011	December 31, 2010
Bank debt	\$ 165,000	\$ 160,800
Working capital deficiency <sup>(1)</sup>	54,738	42,581
Net debt	\$ 219,738	\$ 203,381
Trailing funds from operations <sup>(2)</sup>	\$ 138,504	\$ 122,500
Net debt to trailing funds from operations ratio	1.59	1.66

(1) Working capital excludes bank debt.

(2) Trailing funds from operations is annualized based on the most recent quarter's funds from operations which is calculated as cash provided by operating activities, before settlement of decommissioning obligations and change in non-cash operating working capital.

Celtic targets a net debt to trailing funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

### 14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Accounts receivable	\$ 6,026	\$ 5,306	\$ 4,870	\$ 12,676
Drilling royalty credits	-	5,300	2,906	941
Prepaid expenses and deposits	(876)	(410)	(1,212)	(98)
Accounts payable and accruals	20,796	8,598	9,711	7,709
Change in non-cash working capital	\$ 25,946	\$ 18,794	\$ 16,275	\$ 21,228
Relating to:				
Operating activities	\$ (3,984)	\$ 9,422	\$ (11,988)	\$ 16,590
Investing activities	29,930	9,372	28,263	4,638
Change in non-cash working capital	\$ 25,946	\$ 18,794	\$ 16,275	\$ 21,228

During the reporting period, the Company made the following cash outlays in respect of interest expense:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Interest	\$ 1,512	\$ 1,234	\$ 4,559	\$ 3,939

## **15. FINANCING EXPENSES**

The following table summarizes significant components of the Company's financing expenses during the period:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Interest expense	\$ 1,493	\$ 1,241	\$ 4,596	\$ 4,268
Accretion of decommissioning obligations	525	179	1,007	558
Financing expenses	\$ 2,018	\$ 1,420	\$ 5,603	\$ 4,826

## **16. RELATED-PARTY TRANSACTIONS**

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services.

William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the nine months ended September 30, 2011, the Company incurred \$0.4 million (2010 - \$0.2 million) to BLG for legal fees and disbursements. The Company expects to continue using the services of this law firm from time to time.

## **17. SUBSEQUENT EVENTS**

On October 7, 2011, Celtic issued 6.0 million common shares by way of a short form prospectus at an issue price of \$25.00 per common share for gross proceeds of \$150.0 million. In conjunction with this offering, the Company provided the syndicate of underwriters an over-allotment option to purchase an additional 0.9 million common shares at a price of \$25.00 per common share, which was exercised on October 25, 2011 providing incremental gross proceeds of \$22.5 million.

On November 1, 2011, the Company entered into an agreement with a major petroleum company to acquire natural gas assets at Grande Cache, Alberta, adjacent to Celtic's core area at Resthaven, for cash consideration of \$50.0 million, before closing adjustments. The acquisition has an effective date of July 1, 2011 and is subject to standard industry closing conditions. Closing is expected to occur during the second week of December 2011. The consideration to be paid by Celtic under the agreement will be financed by bank debt.

## **18. TRANSITION TO IFRS**

The Company's financial statements for the year ending December 31, 2011 will be the first annual financial statements prepared in accordance with IFRS. These interim financial statements were prepared as described in Note 1, including the application of IFRS 1, "First-time Adoption of International Financial Reporting Standards". Prior to the adoption of IFRS, the Company followed Canadian generally accepted accounting principles ("previous GAAP"). A reconciliation of the impact to equity between previous GAAP and IFRS as at September 30, 2010 is provided herein.

Comparative financial information is required on first time adoption of IFRS and therefore the Company has adopted IFRS as at January 1, 2010 (the "Transition Date"). IFRS generally requires full retrospective application of the standards in effect; however, IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to this requirement.

The Company has applied the following optional exemptions:

Full cost oil and gas accounting - IFRS 1 provides the option for entities using full cost accounting for oil and gas activities under previous GAAP to measure oil and gas assets at the Transition Date at the historical net book value or at fair value, rather than applying IFRS rules retrospectively. The Company elected to measure its oil and gas assets at the net book value determined under previous GAAP, resulting in undeveloped land costs being reclassified to E&E assets. The remaining development and production assets that were accumulated in a country cost centre under previous GAAP could be allocated to the cost centre's underlying assets pro-rata using reserve volumes or values. The Company elected to allocate these assets using reserve quantities.

Decommissioning obligations - For entities taking the full cost exemption described above, IFRS 1 requires that entities measure decommissioning obligations in accordance with IAS 37 "Provisions, Contingent Liabilities and Contingent Assets", as at the Transition Date and that any difference between this amount and the carrying amount of those liabilities determined under the Company's previous GAAP, be recognized directly in retained earnings.

Share based payments - IFRS 2 "Share-based Payment", requires retrospective application of its provisions to equity instruments granted after November 7, 2002. The IFRS 1 exemption allows first-time adopters to not apply IFRS 2 to equity instruments that were granted prior to November 7, 2002. It also allows the first-time adopter to not apply IFRS 2 to equity instruments granted after November 7, 2002 that vested before the Transition Date. The Company elected to use these exemptions provided under IFRS 1.

Business Combinations - IFRS 3 "Business Combinations" has not been applied to acquisitions that occurred before January 1, 2010.

Borrowing costs - IAS 23 "Borrowing Costs", requires capitalization of borrowing costs relating to qualifying assets. The Company elected to apply the IFRS 1 exemption whereby an entity is permitted to commence capitalization of borrowing costs relating to qualifying assets prospectively from January 1, 2010. The Company did not capitalize any borrowing costs under Canadian GAAP and did not identify any qualifying expenditures in 2010.

## RECONCILIATION OF STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY AS AT SEPTEMBER 30, 2010

(CA\$ thousands)	Previous GAAP	Jan 1, 2010 Adjustments	IFRS Adjustments			IFRS
			DO <sup>(2)</sup>	SBC <sup>(3)</sup>	PP&E <sup>(4)</sup>	
			[Note 18 b]	[Note 18 c]	[Note 18 d,e,f]	
<b>SHAREHOLDERS' EQUITY</b>						
Shareholders' capital	290,689					<b>290,689</b>
Contributed surplus	6,507	1,498		832		<b>8,838</b>
Retained earnings and AOCI <sup>(1)</sup>	108,533	(14,172)	(217)	(832)	18,865	<b>112,177</b>
Total shareholders' equity	405,729	(12,674)	(217)	0	18,865	<b>411,704</b>

(1) Accumulated other comprehensive income has been abbreviated as "AOCI".

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Property, plant and equipment has been abbreviated as "PP&E".

**RECONCILIATION OF STATEMENT OF PROFIT (LOSS) AND COMPREHENSIVE INCOME (LOSS)  
FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2010**

(CA\$ thousands, except per share amounts)	Previous GAAP	Reclass [Note 18 a]	IFRS Adjustments			IFRS
			DO <sup>(2)</sup> [Note 18 b]	SBC <sup>(3)</sup> [Note 18 c]	PP&E <sup>(4)</sup> [Note 18 d,e,f]	
<b>Revenue</b>						
Oil and gas	47,989					<b>47,989</b>
Royalties	(4,770)					<b>(4,770)</b>
	43,219	-	-	-	-	<b>43,219</b>
<b>Expenses</b>						
Production	12,327					<b>12,327</b>
Transportation	601					<b>601</b>
Financing <sup>(1)</sup>	1,241	84	95			<b>1,420</b>
General and administrative	1,014					<b>1,014</b>
Share based compensation	809			503		<b>1,312</b>
Depletion, depreciation and amortization	28,240	(84)			2,821	<b>30,977</b>
Asset Expiries	-				846	<b>846</b>
	44,232	-	95	503	3,667	<b>48,497</b>
<b>Profit (loss) before other items and income taxes</b>	(1,013)	-	(95)	(503)	(3,667)	<b>(5,278)</b>
Gain on derivative financial instruments <sup>(1)</sup>	-	223				<b>223</b>
Realized gain on derivative financial instruments	2,927	(2,927)				<b>-</b>
Unrealized loss on derivative financial instruments	(2,704)	2,704				<b>-</b>
Gain (loss) on sale of assets	-				2,966	<b>2,966</b>
<b>Profit (loss) before income taxes</b>	(790)	-	(95)	(503)	(701)	<b>(2,089)</b>
Deferred income tax expense (recovery)	9		(24)		(177)	<b>(192)</b>
<b>Profit (loss) and comprehensive income (loss)</b>	(799)	-	(71)	(503)	(524)	<b>(1,897)</b>
<b>Profit (loss) per common share</b>						
Basic	\$ 0.01					<b>\$ (0.02)</b>
Diluted	\$ 0.01					<b>\$ (0.02)</b>

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Property, plant and equipment has been abbreviated as "PP&E".

**RECONCILIATION OF STATEMENT OF PROFIT (LOSS) AND COMPREHENSIVE INCOME (LOSS)  
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010**

(CA\$ thousands, except per share amounts)	Previous GAAP	Reclass [Note 18 a]	IFRS Adjustments			IFRS
			DO <sup>(2)</sup> [Note 18 b]	SBC <sup>(3)</sup> [Note 18 c]	PP&E <sup>(4)</sup> [Note 18 d,e,f]	
<b>Revenue</b>						
Oil and gas	169,000					<b>169,000</b>
Royalties	(20,121)					<b>(20,121)</b>
	148,879	-	-	-	-	<b>148,879</b>
<b>Expenses</b>						
Production	41,057					<b>41,057</b>
Transportation	2,236					<b>2,236</b>
Financing <sup>(1)</sup>	4,268	269	289			<b>4,826</b>
General and administrative	3,403					<b>3,403</b>
Share based compensation	2,414			832		<b>3,246</b>
Depletion, depreciation and amortization	84,431	(269)			4,826	<b>88,988</b>
Asset Expiries	-				1,694	<b>1,694</b>
	137,809	-	289	832	6,520	<b>145,450</b>
<b>Profit (loss) before other items and income taxes</b>						
	11,070	-	(289)	(832)	(6,520)	<b>3,429</b>
Gain on derivative financial instruments <sup>(1)</sup>	-	3,264				<b>3,264</b>
Realized gain on derivative financial instruments	2,253	(2,253)				<b>-</b>
Unrealized gain on derivative financial instruments	1,011	(1,011)				<b>-</b>
Gain (loss) on sale of assets	-				32,036	<b>32,036</b>
<b>Profit (loss) before income taxes</b>						
	14,334	-	(289)	(832)	25,516	<b>38,729</b>
Deferred income tax expense (recovery)	4,701		(73)	-	6,652	<b>11,280</b>
<b>Profit (loss) and comprehensive income (loss)</b>						
	9,633	-	(217)	(832)	18,865	<b>27,449</b>
<b>Profit (loss) per common share</b>						
Basic	\$ 0.11					<b>\$ 0.31</b>
Diluted	\$ 0.11					<b>\$ 0.30</b>

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Property, plant and equipment has been abbreviated as "PP&E".

## **EXPLANATORY NOTES**

The impact on the Company's previously reported financial statements for the year ended December 31, 2010 and opening balance sheet as at January 1, 2010 is disclosed in the Company's unaudited interim financial statements for the period ended March 31, 2011. The following provides a summary of significant adjustments to shareholders' equity as at September 30, 2010 and to profit (loss) and comprehensive income (loss) for the three and nine months ended September 30, 2010:

### **a) Reclassifications**

#### *Gain on derivative financial instruments*

Realized and unrealized gains or losses on derivative financial instruments are presented as a single financial statement line item on the statement of profit (loss) and comprehensive income (loss) and detailed in Note 9 to the financial statements.

#### *Accretion on decommissioning obligations*

Under previous GAAP, accretion on decommissioning obligations was included in depletion, depreciation and accretion. Under IFRS, accretion is presented as a financing expense in the statement of profit (loss) and comprehensive income (loss) and detailed in Notes 7 and 15 to the financial statements.

### **b) Decommissioning obligations**

In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and IFRS 1, the Company revalued its decommissioning obligations, known as asset retirement obligations under previous GAAP, using a risk free discount rate at January 1, 2010 and recognized the difference directly in retained earnings. Under previous GAAP, the Company's asset retirement obligations were discounted using an average credit-adjusted risk free rate of 8.5%, whereas under IFRS, the Company discounted its decommissioning obligations using an average risk free rate of approximately 3.9%. As a result of discounting the obligation at a lower rate, the value of the Company's decommissioning liability increased by \$14.6 million as of January 1, 2010. Correspondingly, accretion expense for the three and nine months ended September 30, 2010 increased by \$0.1 million and \$0.3 million, respectively. The net increase in accretion expense under IFRS represents the impact of a higher opening obligation as the basis for the expense, partially offset by the application of a lower rate.

### **c) Share based compensation**

Under the previous GAAP, the Company recognized the expense associated with share based compensation on a straight-line basis and did not incorporate a forfeiture rate at the grant date. Conversely under IFRS, the Company is required to recognize the expense using graded vesting awards and make an estimate of the number of options expected to ultimately vest. As a result, share based compensation expense increased by \$0.5 million and \$0.8 million for the three and nine months ended September 30, 2010, respectively, with a corresponding increase in contributed surplus.

### **d) Depletion, depreciation and amortization**

Upon transition to IFRS, the Company adopted a policy of depleting development and production assets on a unit of production basis over proved reserves. The depletion policy under previous GAAP was based on units of production over proved reserves, however depletion was done on the full Canadian cost pool under the previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e. fields or combinations thereof). As a result of depleting at the major area level, depletion, depreciation and amortization expense increased by \$2.8 million for the three months ended September 30, 2010, and by \$4.8 million for the nine months ended September 30, 2010.

**e) Asset expiries**

Under the previous GAAP, costs associated with mineral leases were classified within property, plant and equipment and excluded from the depletable cost base until expiry, at which point the costs would be recognized as an expense over time through depletion. Under IFRS, mineral leases are classified as E&E and are considered impaired upon expiry. Asset expiries of \$0.8 million and \$1.7 million were recorded for the three and nine months ended September 30, 2010, respectively.

**f) Gains and losses on the sale of assets**

Under previous GAAP, the Company did not recognize gains or losses on the disposition of capital assets. Rather, the proceeds of sale were charged as a reduction of the full cost pool, given that the disposition did not cause a change in the depletion factor by more than 20%. Under IFRS, a gain (loss) is recorded to the extent that the proceeds exceed (are less than) the carrying amount of the asset. As a result of non-core property dispositions, the Company recognized a gain of \$3.0 million for the quarter ended September 30, 2010, and a cumulative gain of \$32.0 million for the nine months ended September 30, 2010.

**g) Statement of cash flows**

The transition from previous GAAP to IFRS has had no effect on the cash flows generated by the Company. The reconciling items between the previous GAAP presentation and the IFRS presentation have no net impact on the reported cash flows provided by or used in operating, financing and investing activities.

# CORPORATE INFORMATION

## BOARD OF DIRECTORS

ROBERT J. DALES<sup>2,3,4,6</sup>

President, Valhalla Ventures Inc.

WILLIAM C. GUINAN<sup>1,5</sup>

Partner, Borden Ladner Gervais LLP

ELDON A. MCINTYRE<sup>2,3,4,6</sup>

President, Jarrod Oils Ltd.

NEIL G. SINCLAIR<sup>2,4,5,6</sup>

President, Sinson Investments Ltd.

DAVID J. WILSON<sup>3,5</sup>

President & Chief Executive  
Officer, Celtic Exploration Ltd.

## OFFICERS

DAVID J. WILSON

President & Chief  
Executive Officer

SADIQ H. LALANI

Vice President, Finance &  
Chief Financial Officer

MICHAEL R. SHEA

Vice President, Land

ALAN G. FRANKS

Vice President, Operations

<sup>1</sup> Chairman of the Board

<sup>2</sup> Member of the Audit Committee

<sup>3</sup> Member of the Reserves Committee

<sup>4</sup> Member of the Compensation  
Committee

<sup>5</sup> Member of the Disclosure  
Committee

<sup>6</sup> Member of the Nominating  
Committee

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Fax: 403.201.9163

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## REGISTRAR AND TRANSFER AGENT

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## LEGAL COUNSEL

BORDEN LADNER GERVAIS LLP

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Calgary, Alberta T2P 4H2

## BANKERS

NATIONAL BANK OF CANADA

Suite 2700, 530 Eighth Avenue S.W.  
Calgary, Alberta T2P 3S8

## AUDITORS

PRICEWATERHOUSECOOPERS LLP

Suite 3100, 111 Fifth Avenue S.W.  
Calgary, Alberta T2P 5L3

## EVALUATION ENGINEERS

SPROULE ASSOCIATES LIMITED

Suite 900, 140 Fourth Avenue S.W.  
Calgary, Alberta T2P 3N3

## STOCK EXCHANGE LISTING

TORONTO STOCK EXCHANGE

Trading symbol "CLT"

## ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
MD&A	Management's Discussion and Analysis
GJ	gigajoules
T	tonnes
MT	thousand tonnes
AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
CICA	Canadian Institute of Chartered Accountants
BIT	before income taxes
WTI	West Texas Intermediate

## CONVERSION OF UNITS

Imperial = Metric

1 acre = 0.4 hectares

2.5 acres = 1 hectare

1 bbl = 0.159 cubic metres

6.29 bbls = 1 cubic metre

1 foot = 0.3048 metres

3.281 feet = 1 metre

1 mcf = 28.2 cubic metres

0.035 mcf = 1 cubic metre

1 mile = 1.61 kilometres

0.62 miles = 1 kilometre

1 mmbtu = 1.054 GJ

0.949 mmbtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE.



CELTIC'S NEW ADDRESS EFFECTIVE MAY 1, 2011:

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