Management's Discussion and Analysis for the

Three Months Ended September 30, 2011

SOUTHERN PACIFIC
RESOURCE CORP.

Condensed Interim Consolidated Financial Statements for the Three months ended September 30, 2011 and 2010 (unaudited)

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statement of Financial Position
Stated in thousands of Canadian dollars (Unaudited)

	September 30, 2011	June 30, 2011	July 1, 2010
Assets			
Current assets			
Cash and cash equivalents (notes 4 and 7)	**$ 258,590**	$ 322,927	$ 63,505
Trade and other receivables	**10,425**	13,091	7,377
Prepaid expenses and deposits	**1,065**	1,157	232
Derivative assets (note 12)	**6,090**	570	273
	276,170	337,745	71,387
Non-current assets			
Exploration and evaluation assets (note 5)	**157,973**	155,562	172,546
Property, plant and equipment (note 6)	**485,384**	385,580	105,264
	$ 919,527	$ 878,887	$ 349,197
Liabilities and Shareholders' Equity			
Current liabilities			
Trade and accrued payables	**$ 87,828**	$ 75,574	$ 11,458
Current portion of long term debt (note 7)	**2,857**	2,652	-
	90,685	78,226	11,458
Non-current liabilities			
Long term debt (note 7)	**400,760**	379,148	-
Decommissioning liability (note 8)	**24,579**	22,127	10,185
Deferred income tax liability	**49,451**	46,197	38,761
	565,475	525,698	60,404
Shareholders' equity			
Share capital (note 9)	**306,994**	306,499	283,603
Equity component of convertible debentures (note 7)	**25,284**	25,284	-
Contributed surplus (note 10)	**25,458**	24,393	23,064
Deficit	**(3,684)**	(2,987)	(17,874)
	354,052	353,189	288,793
	$ 919,527	$ 878,887	$ 349,197

Commitments (note 13)

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statement of Comprehensive Income (Loss)
Stated in thousands of Canadian dollars except per share amounts (Unaudited)

Three months ended September 30,	**2011**	2010
Revenues and Other Income		
Petroleum revenue, net of royalties (note 14)	**$ 17,154**	$ 17,345
Gain on risk management contracts	**5,966**	98
	23,120	17,443
Expenses		
Operating	**4,185**	3,626
Exploration and evaluation	**-**	224
General and administrative	**2,205**	1,253
Finance (note 15)	**168**	61
Stock based compensation	**913**	1,028
Foreign exchange loss	**6,661**	**-**
Depletion and depreciation	**6,428**	8,379
	20,560	14,571
Income before income taxes	**2,560**	2,872
Deferred income tax expense	**3,257**	1,077
Net (loss) income and comprehensive (loss) income	**(697)**	1,795
Income per share - basic and diluted	**$(0.00)**	$0.01
Weighted average number of shares outstanding:		
Basic	**339,305**	200,385
Diluted	**345,339**	202,751

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.

Condensed Consolidated Statement of Changes in Shareholders' Equity
Stated in thousands of Canadian dollars (Unaudited)

Three months ended September 30,	**2011**	2010
Share Capital		
Balance, July 1	**$ 306,499**	$ 283,603
Exercise of options	**495**	240
Share issue costs	**-**	(12)
Balance, September 30	**306,994**	283,831
Contributed Surplus		
Balance, July 1	**24,393**	23,064
Options exercised	**(292)**	(126)
Stock-based compensation	**1,357**	1,028
Balance, September 30	**25,458**	23,966
Retained Deficit		
Balance, July 1	**(2,987)**	(17,874)
Net (loss) earnings	**(697)**	1,795
Balance, September 30	**$ (3,684)**	$ (16,079)

See accompanying notes to financial statements.

SOUTHERN PACIFIC RESOURCE CORP.
Condensed Consolidated Statement of Cash Flows
Stated in thousands of Canadian dollars (Unaudited)

Three months ended September 30,	**2011**	2010
Cash provided by (used in)		
Operating activities:		
Net income (loss)	**$ (697)**	$ 1,795
Adjustments for:		
Depletion and depreciation	**6,428**	8,379
Finance expense	**35**	6
Exploration and evaluation	**-**	224
Unrealized loss on foreign exchange	**6,258**	-
Unrealized gain on risk management contracts	**(5,519)**	(169)
Stock based compensation	**913**	1,028
Deferred taxes	**3,257**	1,077
	10,675	12,340
Change in non-cash operating working capital	**468**	(2,219)
Decommissioning expenditures (note 8)	**-**	(2)
	11,143	10,119
Financing activities:		
Issuance of common shares, net of share issuance costs (note 9)	**202**	101
Repayment of long-term debt	**(711)**	-
	(509)	101
Investing activities:		
Exploration and evaluation expenditures (note 5)	**(2,328)**	-
Property plant and equipment expenditures (note 6)	**(102,798)**	(7,302)
Petroleum and natural gas dispositions	**1,786**	-
Net change in non-cash investing working capital	**14,219**	150
	(89,121)	(7,152)
Net (decrease) increase in cash and cash equivalents	**(78,487)**	3,068
Foreign exchange gain on cash balances (note 12)	**14,150**	-
Cash and cash equivalents, beginning of period	**322,927**	63,505
Cash and cash equivalents, end of period	**$ 258,590**	$ 66,573

Supplementary cash flow information		
Finance costs paid and capitalized (note 6)	**$ 9,796**	$ -

See accompanying notes to the financial statements

1. Incorporation and nature of operations:

Southern Pacific Resource Corp., its subsidiaries; Southern Pacific Energy Ltd., Southern Pacific Resource Partnership, and 1614789 Alberta Ltd. (collectively the "Company") were either incorporated under the Business Corporation Act of Alberta or organized under the partnership laws of the Province of Alberta. The Company is a publicly traded company headquartered at 1700, 205 5th Avenue SW, Calgary, Alberta, Canada and its shares trade on the Toronto Stock Exchange "TSX" under the symbol "STP".

The Company's operations are comprised of production of heavy oil from a thermal project in Saskatchewan known as STP-Senlac, development of an in-situ project in Alberta known as STP-McKay Phase 1 for the production of bitumen, and are involved in the exploration and development of other in-situ oilsands properties located in northern Alberta, Canada. The Company has filed an application for an expansion in-situ project in McKay known as STP-McKay Phase 2.

2. Basis of preparation:

(a) Statement of Compliance

The September 30, 2011 condensed interim consolidated financial statements (the "financial statements") are the Company's first financial statements prepared under International Financial Reporting Standards ("IFRS"). The Company's transition date to IFRS was July 1, 2010 and results for each of the periods from July 1, 2010 to June 30, 2011 have been restated from the previous Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS. These restated comparative financial statements are presented as comparative figures for this and future quarterly and annual financial statements. The transition to IFRS resulted in changes to the Company's accounting policies and these are disclosed in Note 16 along with reconciliations of the statements under previous Canadian GAAP to their IFRS values. These financial statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with International Accounting Standard (IAS) 34, "Interim Financial Reporting".

The policies applied in these financial statements are based on IFRS issued and outstanding as of November 14, 2011, the date the Audit Committee approved the financial statements. Any subsequent changes to IFRS that take effect in the Company's annual financial statements for the year ending June 30, 2012 could result in restatement of these financial statements, including the transitional adjustments recognized on the change-over to IFRS.

The financial statements should be read in conjunction with the Company's Canadian GAAP annual financial statements for the year ended June 30, 2011. These financial statements do not include all the necessary annual disclosures in accordance with IFRS.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis except for the revaluation of derivative instruments to fair value.

(c) Functional and presentation currency

These interim consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgment

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur.

Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property, plant and equipment and the related accrued liability. In addition, estimates regarding the timing of when major development projects are ready for their planned use affect the amounts recorded in property, plant and equipment or intangible assets.

Amounts recorded for depletion and obligations, and impairment calculations and amounts used in the determination of future taxes are based on estimates of petroleum, natural gas and bitumen reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs and the related future cash flows are subject to measurement uncertainty, and the impact in the financial statements of future periods could be material.

Amounts recorded for depreciation of major facilities and equipment and pipeline transportation equipment are based on management's best estimate of their useful lives. Accordingly, those amounts are subject to measurement uncertainty.

Amounts recorded for decommissioning obligations are based on management's best estimate of expenditures required to settle the present obligation as well as changes in the discount rate. Accordingly, those amounts are subject to measurement uncertainty.

Amounts recorded for stock based compensation expense are based on management's best estimate of expected volatility of the Company's share price, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

The estimated fair value of the Company's financial assets and liabilities are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

3. Significant accounting policies:

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany transactions and balances have been eliminated upon consolidation. Operations of acquired businesses are included from their respective acquisition dates.

(b) Cash and cash equivalents:

Cash and cash equivalents include cash and term deposits with original maturities of three months or less.

(c) Exploration and evaluation assets ("E&E"):

E&E expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred and recorded in the statement of comprehensive income.

Costs directly associated with the exploration and evaluation of oil and gas reserves are initially capitalized. The costs included are those expenditures where technical feasibility and commercial viability have not yet been determined and include costs such as land rights in areas with no recoverable assigned reserves, geological and geophysical costs, and the costs of drilling exploration wells.

E&E costs are classified as intangible assets and are not depleted. E&E assets are transferred to property, plant, and equipment when they are determined to meet technical feasibility and commercial viability. If reserves are not found in commercial quantities then the capitalized costs are assessed for impairment and any impairment required is charged to the statement of comprehensive income.

The carrying amount of E&E assets is tested for impairment at least annually, when facts or circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount and upon transfer to property, plant and equipment.

(d) Property, plant and equipment:

Property, plant and equipment is initially recognized at cost which represents all costs directly associated with the development of oil and natural gas reserves where technical feasibility and commercial viability is determined. Costs include drilling of development wells, tangible costs of facilities and infrastructure construction, proved property acquisitions, decommissioning liabilities, and transfers of successful E&E assets.
Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use. The Company also capitalizes expenses, including wages, salaries, benefits and other office costs that are directly attributable to bringing qualifying assets into operation.

Depletion and depreciation of petroleum and natural gas properties is calculated using the unit of production method based upon the production volumes, before royalties, in relation to the recoverable petroleum and natural gas reserves as estimated by independent engineers. In determining costs subject to depletion, the Company includes estimated future costs to be incurred in developing recoverable reserves and excludes residual value. For depletion purposes, natural gas volumes are converted to equivalent volumes based upon a relative energy content of six thousand cubic feet of natural gas to one barrel of oil.

Where significant parts of an item of property, plant and equipment have different lives than the oil and gas reserves, they are accounted for as separate items (major components) and depreciated over the life of the component.

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as capital only when they increase the future economic benefits of the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing recoverable reserves and enhancing production from such reserves. All other expenditures are recognized in comprehensive income or loss as incurred.

Other capital assets are recorded at cost. The Company provides for amortization using the declining balance method for computer equipment and software, office equipment and furniture at rates designed to amortize the cost over their estimated useful lives ranging from 30% to 50%.

Property plant and equipment are grouped into CGUs and are reviewed quarterly for indicators of impairment. If these indicators suggest that an impairment may exist, an impairment test is performed in which the carrying amounts of these assets are written down to their recoverable amount, which is the higher of fair value less costs to sell (“FVLCS”) and value-in-use (“VIU”). In determining FVLCS recent market transactions are taken into account and if these are not available then a valuation model is used. The discounted cash flows used in the model are generally derived from information contained in the reserve report. VIU is determined by estimating the discounted cash flows expected from the continuing use of the asset.

Impairment losses recognized in prior periods are assessed at each reporting date for indications that the loss has decreased or no longer exists. The impairment loss can be reversed up to the original carrying value of the asset that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized. This reversal is recognized in the statement of comprehensive income.

When assets are sold, a gain or loss is calculated by comparing the disposal proceeds with the carrying amount of the asset. This gain or loss is recognized in the statement of comprehensive income.

(e) Revenue recognition:

Revenue associated with the production and sale of oil, natural gas and natural gas liquids owned by the Company is recognized when title passes to the customer and collectability being reasonably assured. Interest income is recognized when earned.

(f) Share based compensation:

Share options issued are accounted for in accordance with fair value accounting for share-based compensation. The associated share compensation expense is charged to the statement of comprehensive income with a corresponding increase to contributed surplus, over the vesting period of the option. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. The fair value of each stock option granted is estimated on the date of grant using a Black–Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. As the options are exercised, consideration paid, along with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. In the event that vested options expire, previously recognized compensation expense associated with such stock options is not reversed. All forfeited options are cancelled by the Company immediately, no stock based compensation is recorded on these options in future periods and any related unvested stock based compensation in the current period is reversed.

(g) Per share amounts:

Basic net earnings (loss) per share is calculated using the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the weighted average number of common and common equivalent shares outstanding during the period using the treasury stock method. This method assumes the proceeds from the exercise of dilutive options and warrants are used to purchase common shares at the weighted average market price during the period. Common equivalent shares consist of the incremental common shares issued upon the exercise of in the money stock options and warrants unless their effect is anti-dilutive.

(h) Foreign Currency Translation:

Transactions in foreign currencies are translated into Canadian dollars at exchange rates prevailing at the transaction dates. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Resulting exchange gains and losses are included in earnings.

(i) Income taxes:

Tax expense comprises current and deferred taxes. Tax expense is recognized in the statement of operations except when it relates to items recognized directly in other comprehensive income (loss) and equity, in which case the tax is also recognized in other comprehensive income (loss) and equity. Income tax assets and liabilities are presented separately in the consolidated balance sheet except where there is a right of set-off within fiscal jurisdictions and an intention to settle such balances on a net basis.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to income tax payable in respect of previous years.

The Company follows the liability method of accounting for deferred income taxes. Under this method, deferred income tax assets and liabilities are recorded based on the temporary differences between the carrying amount of the balance sheet items and their corresponding tax bases. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. In addition, the future benefits of income tax assets, including unused tax losses, are recognized, subject to a valuation allowance, to the extent that it is probable that such future benefits will ultimately be realized. Deferred income tax assets and liabilities are measured using substantively enacted tax rates and laws expected to apply when the differences are either reversed or realized.

(j) Joint interest operations:

A portion of the Company's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(k) Business combinations:

Business combinations are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the statement of comprehensive income. The associated transaction costs are expensed when incurred.

(l) Financial instruments:

A financial instrument is any contract that gives rises rise to a financial asset of one entity and a financial liability or equity instrument to another. Upon initial recognition all financial instruments, including derivatives, are recognized on the statement of financial position at fair value. Subsequent measurement is then based on financial instruments being classified into one of the following five categories: 1) loans and receivables, 2) assets held-to-maturity, 3) assets available-for-sale, 4) other financial liabilities, and 5) fair value through profit or loss. Financial instruments classified as fair value through profit or loss or available-for-sale items as a result of initially adopting this section are measured at fair value. Gains or losses on subsequent measurement of fair value through profit or loss are recognized in net income (loss), while gains and losses on subsequent measurement of available-for-sale items are recognized as an adjustment to other comprehensive income.

At September 30, 2011, the Company's financial instruments include cash and cash equivalents, trade and other receivables, risk management contracts, trade and accrued payables, bank debt and convertible debentures. Cash and cash equivalents are measured at fair value consistent with the "fair value through profit or loss" classification. Net gains and losses arising from changes in fair value are recognized in net income upon derecognition or impairment. Accounts receivable are measured at amortized cost consistent with the "loans and receivables" classification. Loans and receivables are subsequently measured at their amortized cost, using the effective interest method. Under this method, estimated future cash receipts are discounted over the asset's expected life, or other appropriate period, to its net carrying value. Accounts payable and accrued liabilities, bank loans, and the liability portion of convertible debentures are measured at amortized cost using the effective interest method, consistent with the "other financial liabilities" classification. Equity instruments are recorded at the proceeds received with direct issue costs deducted.

The Company has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting. As a result, all financial derivative contracts are classified as "fair value through profit and loss" and recorded on the statement of financial position at fair value at each reporting date. Gains and losses on these contracts are recognized in net income (loss). Attributable transaction costs are recorded in the statement of comprehensive income.

Embedded derivatives are separated from the host contract and accounted for separately when all three of the following conditions are met: i) the economic characteristics and risks of the host contract and the embedded derivative are not closely related; ii) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and iii) the hybrid instrument is not measured at fair value with changes in fair value recognized in profit or loss. Changes in the fair value of the separated embedded derivative are recognized immediately in the statement of comprehensive income.

On initial recognition, the convertible debentures were classified into debt and equity components at fair value. The liability was valued at fair value using a valuation model that incorporates the redeemable option and this was deducted from the fair value of the convertible debenture as a whole to determine the value of the equity component. Subsequent to the initial recognition, the liability component is remeasured at amortized cost using the effective interest rate method. The equity component is not remeasured subsequent to initial recognition.

(m) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free interest rate. The accretion of the discount is recognized as finance cost. The carrying amounts of provisions are regularly reviewed and updated.

The Company records the fair value of a decommissioning obligation as a liability in the period in which it incurs a legal or constructive obligation associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the assets. The associated decommissioning costs are capitalized as part of the carrying amount of the long lived asset and are depleted using the unit of production method over estimated total proved and probable reserves. Subsequent to the initial measurement of the decommissioning obligation, the obligation is adjusted at the end of each period to reflect the passage of time (accretion), changes in the discount rate and changes in the estimated future cash flows underlying the obligation and is recognized within finance costs on the statement of comprehensive income. Actual abandonment restoration expenditures are charged to the decommissioning obligation as incurred, with any remainder recorded to earnings as a gain or loss.

(n) Recent accounting pronouncements issued but not yet effective:

The following standards have been issued but are not yet effective. They may result in future changes to accounting policies and other note disclosures. Each of these new standards is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted.

IFRS 9 “Financial Instruments” – issued in November 2009 and revised in October 2010. Portions of this standard are still in the process of development and the standard will eventually replace IAS 39 “Financial Instruments: Recognition and Measurement”. IFRS 9 introduces new requirements for classifying and measuring assets and liabilities. The full impact of the standard will not be known until the project is complete.

IFRS 10 "Consolidated Financial Statements" – issued in May 2011. This standard replaces the consolidation requirements in SIC-12 "Consolidation - Special Purpose Entities" and IAS 27 "Consolidated and Separate Financial Statements".

IFRS 11 "Joint Arrangements" – issued in May 2011. This standard replaces IAS 31 "Interests in Joint Ventures" and SIC-13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers".

IFRS 12 "Disclosure of Interests in Other Entities" – issued in May 2011. This is a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities.

IFRS 13 "Fair Value Measurement" – issued in May 2011. This standard applies to other IFRSs that require fair value measurement and sets out a single IFRS framework for measuring fair value and also requires disclosures about fair value measurements.

The following existing standards have been amended:

IAS 1 "Presentation of Financial Statements" – This amendment provides guidance on the presentation of items contained in other comprehensive income (OCI) and their classification within OCI. This is required to be applied beginning on or after July 1, 2012 with earlier adoption permitted.

IAS 19 "Post Employment Benefits" – The amendment makes changes to the recognition and measurement of defined benefit pension expense and expands disclosure for all employee benefit plans. This is required to be applied as of January 1, 2013 with earlier adoption permitted.

Management is assessing the impact of these new standards and amendments but they are not expected to have a material impact on the Company's Consolidated Financial Statements.

4. Cash and cash equivalents:

Cash and cash equivalents are funds primarily intended for the STP-McKay Phase I project. As at September 30 and June 30, 2011, US$50 million is held in a separate collateral escrow account (note 7(b)).

All tabular amounts stated in thousands of Canadian dollars except per share amounts

5. Exploration and evaluation assets ("E&E"):

Balance at July 1, 2010	$172,546
Transferred to property, plant and equipment	(46,437)
Additions	29,760
Exploration and evaluation expense	(307)
Balance at June 30, 2011	$155,562
Additions	2,411
Balance at September 30, 2011	**$ 157,973**

Exploration and evaluation assets are comprised of undeveloped land and oil sands evaluation projects pending the determination of technical feasibility and commercial viability.

During the three months ended September 30, 2011 the Company capitalized $0.1 million (September 30, 2010 – $nil) of directly attributable expenses and $nil of interest and debt service costs (September 30, 2010 – $nil) relating to oil sands exploration and development.

6. Property, plant and equipment:

Cost	**Oil and gas properties**	**Corporate**	**Total**
Balance at July 1, 2010	$104,856	$568	$105,424
Transferred from E&E	46,437	-	46,437
Capital expenditures	251,670	1,129	252,799
Change in decommissioning liabilities	11,500	-	11,500
Balance at June 30, 2011	$414,463	$1,697	$416,160
Capital expenditures	105,251	350	105,601
Change in decommissioning liabilities	2,417	-	2,417
Dispositions	(2,109)	-	(2,109)
Balance at September 30, 2011	**$520,022**	**$2,047**	**$ 522,069**
Accumulated depletion and depreciation			
Balance at July 1, 2010	$ -	$160	$160
Depletion and depreciation	30,152	268	30,420
Balance at June 30, 2011	$30,152	$428	$30,580
Depletion and depreciation	6,302	126	6,428
Dispositions	(323)	-	(323)
Balance at September 30, 2011	**$36,131**	**$554**	**$36,685**

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Carrying Amounts			
As at July 1, 2010	$104,856	$408	$105,264
As at June 30, 2011	$384,311	$1,269	$385,580
As at September 30, 2011	**$483,891**	**$1,493**	**$485,384**

During the three months ended September 30, 2011 the Company capitalized $0.3 million (September 30, 2010 – $nil) of directly attributable expenses and $9.8 million of interest costs and $2.1 million of debt service costs (September 30, 2010 – $nil) relating to property, plant and equipment.

STP-McKay Phase 1 assets amounting to $390.6 million at September 30, 2011 (June 30, 2011 $290.9 million) are currently not being depleted as production has not commenced as the project is currently in construction.

In determining the unit-of-production depletion charge on recoverable reserves, future development costs of $140.1 million (June 30, 2011 $141.7 million) were included in property, plant and equipment.

No impairment losses were recognized during the current or the prior year quarter.

7. Long-term debt:

	Note	**September 30, 2011**	June 30, 2011	July 1, 2010
Revolving credit facility (CDN$30 million)	(a)	$-	$ -	$-
Second lien term loan (US$273.6 million)		**283,555**	263,857	-
Financing transaction costs on second lien term loan		**(15,867)**	(15,867)	-
Amortization of financing costs		**1,890**	1,252	-
Less current portion of second lien term loan		**(2,857)**	(2,652)	-
	(b)	**266,721**	246,590	
Convertible debentures (CDN$172.5 million)		**172,500**	172,500	-
Financing transaction costs on convertible debentures		**(6,339)**	(6,339)	-
Amortization of financing costs and equity		**4,103**	2,622	-
Equity component of convertible debentures		**(36,225)**	(36,225)	-
	(c)	**134,039**	132,558	-
Long-term debt		**$400,760**	$379,148	$-

(a) Revolving credit facility (due January 7, 2014):

The Company has a $30 million revolving credit facility ("facility") with a syndicate of banks. The facility bears interest at a floating rate based on Canadian dollar prime rate, US dollar base rate, bankers' acceptances or LIBOR plus a credit spread above the reference rate. Undrawn amounts are subject to standby fees at approximately 1.4% of the undrawn amount. The facility matures on January 7, 2014 and is extendable at the lenders' discretion. The facility is collateralized by a first ranking security interest on all present and future assets of the Company.

As at September 30, 2011, $2.7 million of letters of credit were issued and outstanding pursuant to the facility. As such, the Company has $27.3 million available under the facility. For the quarter ending September 30, 2011 $0.1 million (September 30, 2010 **-** $0.1 million) was incurred in interest and finance fees.

The facility contains various non-financial covenants that, among other things, restrict the Company with respect to issuing additional debt, making investments and loans, paying dividends, altering the nature of the business and undertaking corporate transactions. The facility has certain financial covenants that include:

- a minimum EBITDA (defined as earnings before finance charges, taxes, depletion, depreciation, accretion, risk management contract gains or losses, stock based compensation expenses and foreign exchange gains and losses) covenant during the construction period of the STP-McKay Phase 1 project of not less than US$35 million based on the 12 months trailing EBITDA;
- a PV-10 (pre-income tax present value of future cash flows from proved and probable reserves utilizing a 10% discount rate) to secured debt ratio starting at 1.75:1 and increasing to 3.00:1 during the term of the facility;
- a secured leverage ratio (the ratio of the term loan and facility debt to the last 12 months trailing EBITDA) after completion of STP-McKay Phase 1 project shall not be greater than 5.0:1 and reduces to 2.75:1 during the term of the facility; and
- debt drawn under this facility to the last 12 months trailing EBITDA ratio shall not exceed 2.0:1.

The Company is in compliance with all covenants under the facility as of September 30, 2011.

(b) Second lien term loan (due January 7, 2016):

The Company raised US$275 million under a second lien term loan ("term loan") for the funding of the STP-McKay project. The term loan bears interest on a floating basis at either the LIBOR rate plus a margin of 8.5% with a LIBOR floor of 2% or the U.S. base rate plus a margin of 7.5% with a U.S. base rate floor of 3%, depending upon whether a Euro loan or a US prime loan is drawn. The term loan requires scheduled quarterly payments of accrued interest and principal in an amount of 0.25% of the outstanding amount with the remaining balance of the term loan due on January 7, 2016. Transaction costs in relation to the issuance of the term loan were $15.9 million. The term loan is secured by a second ranking security interest on all present and future assets of the Company. The effective annualized interest rate for the quarter ended September 30, 2011 was 12.3% which includes interest and amortization of the applicable financing costs.

The term loan contains various non-financial covenants that, among other things, restrict the Company with respect to issuing additional debt, making investments and loans, paying dividends, altering the nature of the business and undertaking corporate transactions. The term loan is subject to the same covenants as the facility discussed in note 7(a) except that it does not include a debt to EBITDA ratio covenant. The Company is in compliance with all covenants under the term loan as of September 30, 2011.

At any time prior to January 7, 2016, the Company may prepay all or part of the term loan. The prepayment premium is 112% in year one, is 102% in year 2, is 101% in year 3 and par in years 4 and 5 of principal outstanding. Upon change of control of the Company, the term loan requires the Company to make an offer to repay at 101% of the principal outstanding. No value was ascribed to the prepayment option as the fair value of this option was not significant at the date of issue or at September 30, 2011.

As at September 30, 2011, US$50 million of the funds from the term loan is held in a separate collateral escrow account with the lender. These funds are available for use providing the Company is not in default of its covenants. After the completion of STP-McKay project, the Company is permitted to use any funds remaining in the deposit account to prepay amounts owing under the term loan at par.

The term loan is translated into Canadian dollars at the period end exchange rate of $1 US = $1.0389 CDN.

(c) Convertible debentures (due June 30, 2016):

The Company issued subordinated unsecured convertible debentures with a face value of $172.5 million on January 7, 2011 for the STP-McKay project. Interest is payable on a fixed basis semi-annually on June 30 and December 31 of each year at the rate of 6%. The convertible debentures mature on June 30, 2016, unless converted prior to that date. The convertible debentures are convertible at any time into common shares, at the option of the holder, at a conversion price of $2.15 per share.

The convertible debentures are redeemable on or after June 30, 2014 by the Company for shares, in whole or in part, at a price equal to the principal amount of the convertible debentures to be redeemed, plus accrued and unpaid interest, provided that the market price of the Company's common shares is at least 130% of the conversion price of the convertible debentures for 20 consecutive trading days.

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Transaction costs related to the debt component of the convertible debentures were $6.3 million. These costs are amortized over the expected life of the convertible debentures using the effective interest method.

As at the date of issuance, the value of the conversion feature of the convertible debentures was accounted for as a separate component of equity in the amount of $25.3 million (after adjusting for related transaction costs of $1.7 million and future income tax adjustments of $9.3 million). The debt component was measured at the issue date as the present value of cash payments of interest and principal under the terms of the convertible debentures using a discount rate of 12.5%. The effective annualized interest rate of the convertible debentures, after giving consideration to the conversion feature option and transaction costs, is 12.2%.

(d) Required debt principal payments:

The required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

	Term loan	Convertible debentures	**Total**
2012	$2,143	$-	**$2,143**
2013	2,857	-	**2,857**
2014	2,857	-	**2,857**
2015	2,857	-	**2,857**
2016	272,841	172,500	**445,341**
Total	$283,555	$172,500	**$456,055**

8. Decommissioning liability:

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the liability associated with the retirement of petroleum and natural gas properties and equipment including well sites, gathering systems and processing facilities.

	Three months ended September 30, 2011	Year ended June 30, 2011
Balance, beginning of period	**$22,127**	$10,185
Liabilities assumed on acquisition	**-**	1,045
Additions and dispositions	**(1,159)**	10,199
Effect of change in estimates	**3,576**	878
Abandonment costs	**-**	(283)
Accretion	**35**	103
Balance, end of period	**$24,579**	$22,127

All tabular amounts stated in thousands of Canadian dollars except per share amounts

The total undiscounted amount of estimated cash flows required to settle the liability is $56.3 million (June 30, 2011 - $56.1 million), which has been discounted using a risk free rate of 2.81% and an inflation rate of 2.5%. Settlements will be funded from general corporate resources at the time of the properties' retirement and removal during the next 2 to 41 years.

9. Share capital:

(a) Authorized:

Unlimited common shares without par value
Unlimited first preferred shares without par value

(b) Issued:

	Number of shares	Amount
Balance, July 1, 2010	322,695	$283,603
Exercise of options	2,421	2,743
Cancelled (1)	(42)	-
Acquisition of North Peace	14,093	20,153
Balance, June 30, 2011	339,167	306,499
Exercise of options	400	495
Balance, September 30, 2011	**339,567**	**$306,994**

(1) The share cancellations were the result of an acquisition whereby the amalgamation agreement provided for the cancellation of shares that were not exchanged into Company shares by a specified date.

(c) Stock options:

The Company has implemented a stock option plan for directors, officers and employees.

	Number of options	Weighted average exercise price
Balance, July 1, 2010	19,395	$1.05
Granted	7,574	1.51
Exercised	(2,421)	0.53
Forfeited	(549)	1.84
Balance, June 30, 2011	23,999	1.23
Granted	635	1.53
Exercised	(400)	0.51
Balance, September 30, 2011	**24,234**	**$1.25**

All tabular amounts stated in thousands of Canadian dollars except per share amounts

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

	Outstanding			Exercisable		
Range of exercise price	Options	Weighted average exercise price	Weighted average remaining life (years)	Options	Weighted average exercise price	Weighted average remaining life (years)
$0.10 - $0.15	1,320	$0.10	2.21	1,320	$0.10	2.21
$0.50 - $0.75	5,526	0.55	2.87	5,526	0.55	2.87
$0.77 - $1.15	3,626	0.97	2.69	3,202	0.96	2.53
$1.17 - $1.75	9,387	1.44	4.41	833	1.20	3.75
$1.76 - $1.92	2,975	1.89	1.84	2,450	1.90	1.27
$3.15 - $3.15	1,400	3.15	0.74	1,400	3.15	0.75
	24,234	**$1.25**	**3.15**	**14,731**	**$1.11**	**2.32**

The weighted average fair value of the options granted is estimated at $1.13 (2010 – $0.70) on the dates of grant using a Black-Scholes option pricing model with the following assumptions:

	2011	2010
Risk free interest rate	**1.8%**	2.3%
Expected life in years	**4.66**	4.04
Expected volatility	**102.0%**	124.6%
Forfeiture rate	**3.26%**	0.51%
Dividend yield	**0%**	0%

(d) Warrants:

Warrant transactions are summarized as follows:

	Number of warrants	Weighted average exercise price
Balance, June 30, 2010	2,127	$1.93
Warrants assumed on acquisition (Note 5(a))	1,953(1)	4.05
Expired	(3,891)	3.04
Balance, June 30, 2011 and September 30, 2011	**189(2)**	**$1.01**

(1) The warrants expired unexercised on December 23, 2010.
(2) At September 30, 2011, 189,000 warrants are exercisable at $1.01 and expire on March 23, 2012.

All tabular amounts stated in thousands of Canadian dollars except per share amounts

(e) Per share amounts:

The Company excluded 10.6 million options (2010 – 15.6 million) and nil warrants (2010 – 1.7 million) and all convertible debentures (2010 – nil) from the calculation of the weighted average number of shares as they were anti-dilutive.

10. Contributed surplus:

	September 30, 2011	June 30, 2011
Balance, beginning of period	**$24,393**	$23,064
Options exercised	**(291)**	(1,481)
Stock-based compensation	**1,356**	2,810
Balance, end of period	**$25,458**	24,393

11. Capital management:

The Company's objective for managing its capital structure is to ensure it has the financial capacity, liquidity and flexibility to fund investment in its in-situ oilsands resources and development of its existing producing properties.

The Company considers its capital structure to include shareholders' equity and long term debt which totals $758.5 million at September 30, 2011 (June 30, 2011 - $731.2 million). The Company's in-situ oilsands properties require significant capital investment prior to cash flow generation. In order to maintain the capital structure, the Company may from time to time issue shares and adjust its capital spending to manage current and projected debt levels and in light of changes in economic conditions. The Company monitors its bank debt level and working capital in order to assess capital and operating efficiency.

The Company's share capital and cash flow is not subject to external restrictions except for certain financial restrictive covenants under long-term debt (note 7). The Company has not paid or declared dividends since its reorganization of management and change in principal business on March 2, 2006.

12. Financial instruments:

The Company is exposed to the following risks in respect of certain financial instruments held:

(a) Credit risk

Credit risk arises from the potential that a counterparty will fail to perform its obligations and cause a financial loss to the Company. The Company is exposed to credit risk from the Company's accounts receivable from purchasers of the Company's natural gas, crude oil and natural gas liquids and from its joint venture partners. Accounts receivable from purchases of the Company's natural gas, crude oil and natural gas liquids are normally collected the 25th day of the month following the production. The Company's policy to mitigate credit risk is to establish marketing relationships with large and reputable companies. The Company has not experienced any material credit loss in the collection of accounts receivable. The Company, however, does receive the majority of its revenue from a single entity and as such is exposed to the credit risks of this company.

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Joint venture accounts receivable are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate risk from joint venture accounts receivable by obtaining partner approval of significant capital expenditures prior to the commencement of the project. The Company does not typically obtain collateral from joint venture partners, however, in the event of non-payment the Company has the ability to withhold future production from joint venture partners where the Company is the operator.

As at September 30, 2011, accounts receivable includes a balance of $0.1 million (June 30, 2011 - $0.1 million) over 90 days, which is considered to be past due. As at September 30, 2011 $0.3 million (June 30, 2011 - $0.3 million) of an allowance for doubtful accounts has been recorded on certain aged receivables.

The Company is potentially exposed to credit risk with respect to cash amounts held in individual banking institutions for balances that are in excess of nominal guaranteed amounts. Cash and cash equivalent balances at September 30, 2011 were held with two banking institutions in Canada; $206.6 million with one and $52.0 million with the other. The Company periodically monitors published and available credit information for all of its banking institutions.

(b) Market risk

The Company recognizes the fair value of its risk management contracts on the balance sheet each reporting period. The change in fair value is recognized as a gain or loss on the statement of operations. The fair value is at a Level 2 which is based on valuation models and techniques where the significant inputs are derived from quoted market prices or indices. At September 30, 2011 the fair value is estimated to be an unrealized gain of $6.1 million (June 30, 2011 - $0.6 million). The following table summarizes the change in fair value of the Company's risk management contracts:

	September 30, 2011	June 30, 2011
Balance, beginning of period	**$570**	**$** 273
Unrealized gain during the period	**5,520**	297
Balance, end of period	**$6,090**	$570

All tabular amounts stated in thousands of Canadian dollars except per share amounts

The Company has the following outstanding contracts as of September 30, 2011:

Type	Contract Term	Volume	Price
Oil collar (WTI)	Jan 1, 2011 to Dec 31, 2011	1,500 bbl/day	US$70.00- $100.00
Oil collar (WTI)	Feb 1, 2011 to Dec 31, 2011	300 bbl/day	US$85.00- $105.00
Oil collar (WTI)	Apr 1, 2011 to Dec 31, 2011	400 bbl/day	US$90.00- $115.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	900 bbl/day	US$85.00- $115.75
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	500 bbl/day	US$90.00- $110.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	700 bbl/day	US$90.00- $115.05
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.10
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.12
Natural gas swap purchase (AECO)	July 1, 2011 to Dec 31, 2011	1,000 gj/day	$3.86
Natural gas swap purchase (AECO)	July 1, 2011 to Dec 31, 2011	1,000 gj/day	$3.84
Natural gas swap purchase (AECO)	Oct 1, 2011 to Dec 31, 2011	1,500 gj/day	$3.80
FX contract (US$)	Jan 1, 2011 to Dec 31, 2011	750 bbl/day	US$70 WTI, at 1.0620 CAD/USD
FX contract (US$)	October 1 to Dec 31, 2011	750 bbl/day	US$85 WTI, at 1.00 CAD/USD
FX contract (US$)	October 1 to Dec 31, 2011	750 bbl/day	US$85 WTI, at 1.0295 CAD/USD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.00 CAD/USD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.0290 CAD/USD

The following table summarizes the consolidated statement of operations effects of the Company's risk management contracts:

	2011	2010
Unrealized gain	**$5,520**	$169
Realized gain (loss)	**446**	(71)
	$5,966	$98

All tabular amounts stated in thousands of Canadian dollars except per share amounts

(c) Liquidity risk

Liquidity risk is that risk that the Company will not have sufficient funds to repay its debts and fulfill its obligations. To manage this risk, the Company follows a conservative financing philosophy, prefunds major development projects, monitors budgets to control costs, and monitors its operating cash flow and working capital.

(d) Fair value

The carrying value of accounts receivable and accounts payable and accrued liabilities approximate the fair value of the respective assets and liabilities due to the short term nature of those instruments. The risk management contracts are recognized on the balance sheet at a Level 2 fair value which is discussed above in note 12(b). Long-term debt is carried at amortized cost and the fair value, based on current market prices, is estimated to be $441.9 million, consisting of the term loan of $285.0 million and the convertible debentures of $157.0 million, including the equity component, based on current market prices.

(e) Interest rate risk

The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest (Note 7).

(f) Currency risk:

The Company is exposed to fluctuations in foreign currency primarily as a result of its U.S. dollar denominated second lien term loan facility, crude oil sales based on U.S. dollar indices and commodity price contracts that are settled in U.S. dollars. The Company had working capital as of September 30, 2011 denominated in U.S. dollars of $144.0 million (June 30, 2011 - $214.4 million).

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The following table summarizes the components of the Company's net foreign exchange loss:

	2011	2010
Unrealized foreign exchange loss (gain) on translation of:		
U.S. denominated second term loan facility	**$20,408**	$-
Foreign currency denominated cash balances	**(14,150)**	-
Unrealized foreign exchange loss	**$6,258**	$-

All tabular amounts stated in thousands of Canadian dollars except per share amounts

13. Commitments:

At September 30, 2011 the Company is committed to annual lease payments, under the terms of a lease for its head office space and other office spaces:

	Amount
2012	**$389**
2013	**409**
2014	**409**
2015	**273**
Total	**$1,480**

At September 30, 2011, as part of normal operations relating to the construction of the STP-McKay Phase 1 SAGD project, the Company has entered into a total of $105.3 million in capital expenditure commitments to be made over the next year.

At September 30, 2011, as part of normal operations, the Company has entered into the following fixed price gas purchase contracts:

Type	Contract Term	Volume	Price
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.14
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.00
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$3.93

14. Petroleum revenue:

	2011	**2010**
Petroleum sales	**$20,769**	$20,701
Royalties	**(3,259)**	(3,007)
Saskatchewan resource surcharges	**(356)**	(349)
Petroleum revenue	**$17,154**	$17,345

All tabular amounts stated in thousands of Canadian dollars except per share amounts

15. Finance expense:

	2011	2010
Standby fees on revolving credit facility	**$133**	$55
Accretion of decommissioning liability	**35**	6
Total finance expense	**$168**	$61

16. Transition to IFRS:

These financial statements are the first prepared under International Financial Reporting Standards. The Company has prepared its opening balance sheet at July 1, 2010 under these standards and has provided reconciliations to its previous results reported under Canadian GAAP. As well, the first year July 1, 2010 to June 30, 2011 of comparative historical results has been restated under IFRS along with reconciliations between Canadian GAAP and IFRS. This transition note explains the material adjustments made to the financial statements under Canadian GAAP to arrive at financial statements under IFRS.

In accordance with IFRS 1 "First Time Adoption of International Financial Reporting Standards" the Company applied the following optional exemptions from full retrospective application of IFRS:

- **Deemed cost of property, plant and equipment -** Full-cost oil and gas companies are allowed to measure oil and gas assets at the date of transition to IFRS at the amount determined under an entity's previous GAAP. This amount was pro-rated to assets within cash generating units using the recoverable reserve volumes at transition date.

- **Decommissioning liabilities -** The difference between the carrying values of the Company's decommissioning liabilities as measured under IAS 37 "Provisions, Contingent Liabilities and Contingent Assets" and their carrying values under Canadian GAAP has been recognized directly in retained earnings.

- **Business combinations -** This election has been taken to not apply IFRS 3 "Business Combinations" retrospectively to past business combinations. The Company has not restated business combinations that took place prior to the July 1, 2010 transition date.

- **Share-based payment transactions -** The election has been applied whereby the share-based payments under IFRS 2 "Share-based Payment" that had vested or settled prior to July 1, 2010 were not required to be retrospectively restated.

- **Borrowing costs -** IAS 23 "Borrowing Costs" has been applied to qualifying assets prospectively as of July 1, 2010.

- **Leases -** The exemption from the full retrospective application of IFRIC 4 "Determining whether an Arrangement contains a Lease" has been taken and arrangements were assessed using the facts at transition date rather than at the inception of the lease.

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Reconciliation of consolidated statement of financial position and shareholders' equity at the date of transition to IFRS, July 1, 2010:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$63,505	$-	$63,505
Trade receivables		7,377	-	7,377
Prepaid expenses and deposits		232	-	232
Derivative assets		273	-	273
		71,387	-	71,387
Non-current liabilities:				
Exploration and evaluation assets	a		172,546	172,546
Property, plant and equipment	a	277,810	(172,546)	105,264
		$349,197	-	$349,197
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$11,458	$-	$11,458
		11,458	-	11,458
Non-current liabilities:				
Decommissioning liability	c	6,449	3,736	10,185
Deferred income tax liability	d	39,770	(1,009)	38,761
		57,677	2,727	60,404
Shareholders' equity:				
Share capital	d	281,579	2,024	283,603
Contributed surplus	e	23,221	(157)	23,064
Deficit	c,d,e	(13,280)	(4,594)	(17,874)
		291,520	(2,727)	288,793
		$349,197	$-	$349,197

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Reconciliation of consolidated statement of financial position and shareholders' equity at the end of the comparative interim period, September 30, 2010:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$66,573	$-	$66,573
Trade receivables		7,184	-	7,184
Prepaid expenses and deposits		870	-	870
Derivative assets		442	-	442
		75,069	-	75,069
Non-current assets:				
Exploration and evaluation assets	a	-	128,673	128,673
Property, plant and equipment	a,b,c	275,161	(126,964)	148,197
		$350,230	$1,709	$351,939
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$9,832	$-	$9,832
		9,832	-	9,832
Non-current liabilities:				
Decommissioning liability	c	6,535	4,016	10,551
Deferred income tax liability	d	40,462	(623)	39,839
		56,829	3,393	60,222
Shareholders' equity:				
Share capital	d	281,807	2,023	283,830
Contributed surplus	e	24,253	(287)	23,966
Deficit	c,d,e	(12,659)	(3,420)	(16,079)
		293,401	(1,684)	291,717
		$350,230	$1,709	$351,939

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Reconciliation of consolidated statement of comprehensive income for the three months ended September 30, 2010:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenues and Other Income				
Petroleum revenue, net of royalties	d	$17,345	$-	$17,345
Gain on risk management contracts		98	-	98
		17,443	-	17,443
Expenses:				
Operating	a	3,626	-	3,626
Exploration and evaluation	a	-	224	224
General and administrative		1,253	-	1,253
Finance	c	141	(80)	61
Depletion and depreciation	b,c	9,952	(1,573)	8,379
Share-based compensation	e	1,158	(130)	1,028
		16,130	(1,559)	14,571
Income before income taxes		1,313	1,559	2,872
Deferred income tax expense	d	692	385	1,077
Net income and comprehensive income		$621	$1,174	$1,795

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Reconciliation of consolidated statement of financial position and shareholders' equity at the end of the last reporting year under previous GAAP, June 30, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$322,927	$-	$322,927
Trade receivables		13,091	-	13,091
Prepaid expenses and deposits		1,157	-	1,157
Derivative assets		570	-	570
		337,745	-	337,745
Non-current assets:				
Exploration and evaluation assets	a		155,562	155,562
Property, plant and equipment	a,b,c	533,615	(148,035)	385,580
		$871,360	$7,527	$878,887
Liabilities and Shareholders' Equity				
Current liabilities:				
Trade and accrued payables		$75,574	$-	$75,574
Current portion of long-term debt		2,652	-	2,652
		78,226		78,226
Non-current liabilities:				
Long-term debt	h	374,186	4,962	379,148
Decommissioning liability	c	10,043	12,084	22,127
Deferred income tax liability	d	38,201	7,996	46,197
		500,656	25,042	525,698
Shareholders' equity:				
Share capital	d	304,476	2,023	306,499
Equity component of convertible debentures	d	40,344	(15,060)	25,284
Contributed surplus	e	24,884	(491)	24,393
Retained earnings (deficit)	c,d,e	1,000	(3,987)	(2,987)
		370,704	(17,515)	353,189
		$871,360	$7,527	$878,887

All tabular amounts stated in thousands of Canadian dollars except per share amounts

Reconciliation of consolidated statement of comprehensive income for the year ended June 30, 2011:

	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenues and Other Income				
Petroleum revenue, net of royalties	d	$76,865	$-	$76,865
Gain on risk management contracts		286	-	286
Interest and other		484	-	484
		77,635	-	77,635
Expenses:				
Operating		15,680	-	15,680
Exploration and evaluation	a	-	456	456
General and administrative		9,527	-	9,527
Finance expense	c	713	(294)	419
Share based compensation	e	3,144	(334)	2,810
Depletion and depreciation	b,c	34,469	(4,049)	30,420
Impairment	g	-	4,461	4,461
		63,533	240	63,773
Other:				
Gain on foreign exchange		1,102	-	1,102
Gain on acquisition		3,585	-	3,585
		4,687	-	4,687
Income before income taxes		18,789	(240)	18,549
Deferred income tax expense	d	4,509	(847)	3,662
Net income and comprehensive income		$14,280	$607	$14,887

Notes:

(a) Exploration & Evaluation assets

Under the previous GAAP exploration and evaluation assets were included in the full cost pool of property, plant and equipment. Under IFRS these assets must be classified separately. At transition the company reclassified $172.5 million from property, plant & equipment to exploration & evaluation assets. Similarly the company reclassified $128.7 million at September 30, 2010 and $155.6 million at June 30, 2011.

Exploration and evaluation expense relates to expired land and was $0.2 million at September 30, 2010 and $0.5 million at June 30, 2011.

(b) Depletion and Depreciation expense

Under the previous GAAP, depletion and depreciation was calculated on a unit-of-production basis for oil and gas properties using proved reserves on a cost center basis that was defined as a country. Under IFRS depletion is calculated using recoverable reserves on a component basis which has resulted in a decrease in depletion expense and an increase in the carrying value of property, plant, and equipment. This amount was $1.6 million at September 30, 2010 and $4.0 million at June 30, 2011.

(c) Decommissioning liability

Under the previous GAAP, asset retirement obligations were discounted using a credit-adjusted risk-free rate of 8.0%. Under IFRS a risk-free rate of 3.08% has been used at transition date July 1, 2010 which resulted in an increase to the decommissioning liability of $3.7 million with the offsetting charge recognized in retained deficit. At September 30, 2010, a rate of 2.75% was used with an increase to the decommissioning liability of $4.0 million and at June 30, 2011 a risk-free rate of 3.11% was used which increased the decommissioning liability by a total of $12.0 million.

In addition, under the previous GAAP, accretion of the discount was included in depletion and depreciation while under IFRS it is included in net finance expense. At September 30, 2010, $0.09 million was reclassified from DD&A to finance expense and offset by a reduction in accretion expense of $0.08 million. At June 30, 2011 the decrease in accretion expense for the year was $0.3 million.

(d) Deferred income tax

Flow-through shares – Under Canadian income tax legislation a company can issue flow-through shares whereby the company incurs qualifying expenditures relating to oil and gas exploratory and development activities and renounces the related income tax deductions to the investors. Generally the flow-through shares are offered at higher than prevailing quoted prices of the shares due to the benefit of the tax deduction to investors. Under IFRS this ‘premium’ of the issued share price over the market price is an adjustment to share capital with the offset to retained earnings. At transition date this amount was $2.0 million including the deferred tax effect.

Share issue costs – These were treated as a temporary difference under the previous GAAP but under IFRS these are treated as an adjustment to share capital when the tax rate changes. At transition date this adjustment was $0.1 million.

Convertible debentures – The convertible debentures liability and equity portions were adjusted for the value of a redemption option. The deferred tax impact on the equity component was a permanent tax difference under previous GAAP, however, under IFRS this is a temporary difference. This adjustment has reduced the equity portion of the convertible debenture and increased deferred tax by $9.3 million for the year ended June 30, 2011. This change also reduced the deferred income tax expense for the year ended June 30, 2011. The expense was reduced because the temporary difference of $9.3 million is reversed over time, as the debt portion of the convertible debenture is accreted. This adjustment was $0.7 million.

Deferred income tax calculated according to IFRS is substantially similar to previous GAAP and arises from the differences in the accounting and tax bases of assets and liabilities. Where balances have changed due to IFRS differences, the amount of deferred income tax liability will be impacted.

Under the previous GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

Under the previous GAAP, Saskatchewan resource payments were classified as a tax however under IFRS they are now classified as a royalty and netted to petroleum revenue.

(e) Share-based compensation

Under the previous GAAP, the company recognized an expense related to share-based payments on a straight-line basis and did not include an estimate of forfeitures. Under IFRS the company is required to recognize the expense over the individual vesting periods for the graded vesting awards and to estimate a forfeiture rate. At transition date this resulted in a $0.2 million decrease to contributed surplus and an increase to retained earnings. At September 30, 2010 this amount was $0.1 million and at June 30, 2011 this amount was $0.3 million.

(f) Adjustments to the consolidated statement of cash flows

The transition from the previous GAAP to IFRS had no significant impact on cash flows generated by the Company.

(g) Impairment

Under IFRS impairment is done on a CGU basis rather than on a cost center basis. The oil and gas assets were impaired at June 30, 2011 for $4.5 million related to assets sold subsequent to June 30, 2011.

(h) Convertible Debentures

Under IFRS the fair value of the liability portion includes a redemption option which increased the value of the liability and decreased the value of the equity portion by $5.0 million for the period ended June 30, 2011. The option was not bi-furcated as it was considered closely related to the host contract.

OVERVIEW

Southern Pacific Resource Corp. ("Southern Pacific" or the "Company") is engaged in the exploration for and development of in-situ oil sands in the Athabasca region of Alberta and the thermal production of heavy oil in Senlac, Saskatchewan. The Company's head office is located in Calgary, Alberta, Canada. Southern Pacific's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "STP."

In this MDA, references to the "Southern Pacific" or the "Company" refer to Southern Pacific Resource Corp. and its subsidiaries on a consolidated basis. The terms "2011" and "2010" are used throughout this document and refer to the fiscal years ended June 30, 2011 and 2010, respectively. References to "first quarter 2012" in this document refer to the three month financial period ended September 30, 2011. References to "first quarter 2011" in this document refer to the comparative three month financial period ended September 30, 2010.

The following Management's Discussion and Analysis ("MD&A") is a review of the operations, current financial position and outlook for Southern Pacific and is prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended June 30, 2011 and the unaudited consolidated financial statements for the three months ended September 30, 2011. This MD&A is dated November 14, 2011. The financial statements and financial data contained in this MD&A are the first financials that have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") in Canadian currency. This is the first quarter for the Company reporting in accordance with IFRS. As such, the comparative periods have also been restated to conform to the new IFRS standards. The adoption of IFRS does not impact the underlying economics of Southern Pacific's operations. Previously, the Company prepared its interim and annual financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP").

Additional information relating to Southern Pacific can be found on SEDAR at www.sedar.com and on Southern Pacific's website at www.shpacific.com.

OVERALL PERFORMANCE

Highlights for the quarter ended September 30, 2011 include the following:

- Averaged overall production of 3,784 barrels per day ("bbl/d") for the quarter, a decrease of 8% over average production of 4,123 bbl/d for the quarter ended September 30, 2010. This reduction was due to a scheduled plant turnaround at the STP-Senlac Thermal Project ("STP-Senlac") which shut in production for nine days during the quarter;
- Achieved funds from operations of $10.7 million for the quarter compared to $12.3 million in the prior period;
- Continued construction of STP-McKay Phase 1 Thermal Project ("STP-McKay Phase 1"). Total project cost estimate was reduced during the quarter to a range of $415 to $440 million. The original budget for the project was $450 million. The Company continues to forecast substantial project completion for the first quarter of calendar 2012, first steam for the second quarter calendar 2012 and first oil in the third quarter of calendar 2012; and
- Prepared and submitted on November 10, 2011, the application for STP-McKay Phase 2, which is expected to add 24,000 bbl/d of bitumen capacity.

OUTLOOK

Southern Pacific remains focused on the construction and operation of STP-McKay Phase 1. The 12,000 bbl/d steam-assisted gravity drainage ("SAGD") project was approved in the fall of 2010, and construction has been underway since. The Company continues to expect the project to be completed within its budgeted time frame and expects the total cost to come in below the original $450 million budget. The revised final project cost estimate is between $415 and $440 million, including the addition of $15 million of scope changes that are expected to enhance the reliability of the plant and reduce operating costs.

The project milestones have most recently been marked by the installation of several significant pieces on the central process facility site. These include the two largest vessels, the evaporator towers, the steam generation boilers, the cogeneration turbines and heat recovery steam generators and several critical modules of the piperack assembly. The Company's decision to build one of the most modularized SAGD process facilities in the industry to date, is paying off as the site construction labour force has been minimized and the components are readily assembled together once they arrive on site. Most of the heat tracing, insulation and instrumentation have been pre-assembled on these modules in the controlled environment of fabrication shops, which has greatly assisted in controlling costs. The components which cannot be shop fabricated, such as the storage tanks and the steel and cement foundations for the components have been substantially completed before the arrival of cold winter temperatures, which again has cut down on additional cost.

As of September 30, 2011, the Company has incurred and fixed approximately $320 million of the downward revised cost estimate of $440 million. Remaining uncommitted capital is approximately $120 million, including a $30 million contingency.

From a timing perspective, Southern Pacific expects first steam to the SAGD well pairs will occur on schedule in the second quarter of calendar 2012. The Company remains fully funded to complete, start up and add production volumes from Phase 1 of the STP-McKay project.

On November 10, 2011, Southern Pacific submitted an application for the STP-McKay Phase 2 Thermal Project ("STP-McKay Phase 2") to the Alberta Energy Resources Conservation Board and Alberta Environment. The application outlines in detail, Southern Pacific's proposal to develop an additional 24,000 bbl/d of bitumen processing capacity on the eastern side of its existing project boundaries, which would bring the total processing capacity to 36,000 bbl/d. The Company has been working on this application for the past nine months and the contents of this document and all appendices are now located on the Company's website. The filing of a complete application for the project marks a significant milestone in Southern Pacific's growth plans. As a result of this filing, Southern Pacific expects a revised reserves report to reflect an increase in the Proven plus Probable ("2P") reserves which can now be classified under the combined process capacity of 36,000 bbl/d within the project area. The Company anticipates regulatory approval to occur in 18 months based on its previous Phase 1 approval which occurred in 15 months.

STP-Senlac located near Unity, Saskatchewan achieved an average production rate of 3,769 bbl/d for the first quarter of fiscal 2012. In September, a two-week scheduled maintenance turnaround was completed in only nine days coming back online six days ahead of schedule. The bi-annual turnaround identified no major integrity issues.

As part of its development strategy, Southern Pacific is now drilling Phase J, a set of three SAGD well pairs, which is scheduled for first production in January 2012. The on stream date has been delayed about one month from earlier projections due to a delay in the drilling rig arriving on site.

Once completed, these three SAGD well pairs will be layered into the facility as capacity becomes available from the declines of existing wells.

The STP-Red Earth Thermal Project ("STP-Red Earth") also commenced operations in the fourth quarter. This 1,000 bbl/d pilot project was re-activated this past spring. The Company is testing three separate well bores, using cyclic steam stimulation ("CSS") as the technique for recovery. Each well bore has a unique configuration and the Company intends to continue testing the wells through the fall of 2011. Following this initial testing, Southern Pacific will analyze the data and determine the next steps in establishing an overall development plan for this project and future expansion plans.

RESULTS OF OPERATIONS

Production

	Three Months Ended September 30,		
	2011	2010	Change
Heavy oil (bbl/day)	**3,769**	4,065	(7%)
Oil and NGLs (bbl/day)	**9**	17	(47%)
Natural gas (mcf/day)	**38**	245	(84%)
Total (boe/day)	**3,784**	4,123	(8%)

Production for the quarter ended September 30, 2011 averaged 3,784 barrels of oil equivalent per day (boe/day), a decrease of 8% over the same period in 2010. The decrease is attributable to the turnaround at STP – Senlac which took production offline for nine days. Exit production was 4,255 boe/d as at September 30, 2011. The oil, natural gas liquids ("NGLs") and natural gas production decreased for the quarter ended September 30, 2011 as a result of the conventional assets being sold July 15, 2011. These conventional assets were considered non-core to Southern Pacific's oil sands development, which averaged 86 boe/d for the quarter ended June 30, 2011.

Product Prices

	Three Months Ended September 30,		
	2011	2010	Change
Heavy oil ($ per bbl)	**59.80**	54.83	9%
Oil and NGLs ($ per bbl)	**27.11**	74.14	(63%)
Natural gas ($ per mcf)	**3.81**	3.87	(2%)
Combined average ($ per boe)	**59.65**	54.58	9%

The heavy oil price received by Southern Pacific was $59.80 per bbl for the quarter ended September 30, 2011, 9% higher than the same quarter in the prior year. The increase in the heavy oil price for the first quarter of 2012 is largely attributable to the increase in the WTI crude oil price partially offset by increased heavy oil differentials. Southern Pacific has entered into commodity hedging contracts to mitigate fluctuations in commodity prices as outlined under Risk Management Activities and Commitments section below.

Oil and NGLs prices received were $27.11 per bbl for the quarter ended September 30, 2011, representing a 63% decrease from the quarter ended September 30, 2010 due to adjustments related to prior periods which were recorded in the current quarter.

Operating Netbacks

	Three Months Ended September 30, 2011	2010	Change
Combined average ($ per boe)	**59.65**	54.58	9%
Royalties ($ per boe)	**(10.38)**	(8.85)	17%
Operating costs ($ per boe)	**(12.02)**	(9.56)	26%
Operating netback ($ per boe)	**37.25**	36.17	3%

Operating netbacks for the quarter ended September 30, 2011 increased by 3% over the same period in the prior year. This increase is due to the higher average combined product price received offset by higher royalties and operating costs.

Oil and Gas Revenue

($ thousands)	Three Months Ended September 30, 2011	2010	Change
Heavy oil	**20,731**	20,503	1%
Oil and NGLs	**23**	111	(79%)
Natural gas	**15**	87	(83%)
Total oil and gas revenue	**20,769**	20,701	0%

Revenue from oil and natural gas sales for the quarter ended September 30, 2011 was $20.7 million, comparable to the same quarter in 2010. The heavy oil revenue increase was a result of higher realized heavy oil pricing offset by slightly lower production volumes. The oil and NGLs revenue as well as natural gas revenue decreased as a result of the sale of these assets on July 15, 2011.

Risk Management Contracts

($ thousands)	Three Months Ended September 30, 2011	2010	Change
Unrealized gain	**5,519**	169	3,166%
Realized gain (loss)	**447**	(71)	-
Risk management contracts	**5,966**	98	5,988%

For the three months ended September 30, 2011, Southern Pacific recorded an unrealized gain on risk management contracts of approximately $5.5 million, compared to an unrealized gain of $0.2 million for the same period in 2010. The unrealized gain of $5.5 million was largely attributable to a hedged WTI oil price that was higher than the market price during the quarter, increasing the value of the risk management contracts. For the three months ended September 30, 2011, the

Company recorded a realized gain on risk management contracts of approximately $0.4 million, compared to a realized loss of $0.1 million for the three months ended September 30, 2010. The realized gain on the risk management contracts represents actual cash received by Southern Pacific as its hedged price exceeded the market price, during the quarter. The intent of these risk management contracts is to protect the downside risk to the Company's cash flow to pursue Southern Pacific's growth plan at STP-McKay. The contracts are listed in detail in the Commitments section of this MD&A.

Royalties

	Three Months Ended September 30,		
($ thousands except for % and per boe)	**2011**	2010	Change
Royalties	**3,259**	3,007	8%
Provincial resource surcharges	**356**	349	2%
	3,615	3,356	8%
% of oil and gas revenue	**17.4%**	16.2%	7%
Per boe	**$10.38**	$8.85	17%

Royalties for the quarter ended September 30, 2011 were $3.6 million, compared to $3.4 million for the same quarter in 2010. Royalties represented 17.4% of total petroleum and natural gas revenue for the quarter ended September 30, 2011, compared to 16.2% in the same quarter of 2010. On a percentage and absolute basis, royalty rates for the quarter have slightly increased due to decreased capital spending and operating costs relative to the prior quarter as well as crown royalty credits received during the prior quarter. The royalty rates at Senlac are on a sliding scale dependent upon the level of capital and operating spending. An increase in capital and operating spending reduces the royalty rate and likewise a reduction in capital and operating spending will increase the royalty rate. Also included within royalties, are provincial resource surcharges that are charged by the province of Saskatchewan and determined as a fixed percentage of provincial resource revenues generated from its Senlac property.

Operating Costs

	Three Months Ended September 30,		
($ thousands except for per boe)	**2011**	2010	Change
Other operating costs	**3,013**	2,596	16%
Natural gas costs	**1,172**	1,030	14%
Operating costs	**4,185**	3,626	15%
Operating costs per boe	**$12.02**	$9.56	26%

A significant component of the operating costs is the purchase of natural gas, which is used to create steam for the thermal recovery of heavy oil. Southern Pacific manages it's natural gas price risk by selectively hedging a portion of its natural gas purchases throughout the year.

In total, operating costs were $4.2 million for the quarter ended September 30, 2011, compared to $3.6 million for the same quarter in 2010. On a per boe basis, operating costs increased to $12.02

for the three months ended September 30, 2011 from $9.56 for the same period in 2010 due to higher workover costs.

Exploration and Evaluation Expenses

Exploration and evaluation expenses for the quarter ended September 30, 2011 were $nil compared to $0.2 million for the quarter ended September 30, 2010. The expenses in the prior quarter relate to lease expiries on undeveloped lands.

General and Administrative Expenses

	Three Months Ended September 30,		
($ thousands except for per boe)	**2011**	2010	Change
General and administrative expenses	**2,205**	1,253	76%
Per boe	**$6.33**	$3.30	92%

General and administrative expenses for the three months ended September 30, 2011 of $2.2 million are higher compared to $1.3 million for the same period in 2010. The increase is due to additional personnel hired and administration costs required for STP-McKay Phase 1 that is under construction.

Finance Expenses

	Three Months Ended September 30,		
($ thousands except for per boe)	**2011**	2010	Change
Interest and financing	**133**	55	142%
Accretion	**35**	6	483%
	168	61	625%
Per boe	**$0.48**	$0.16	200%

Finance expenses for the three months ended September 30, 2011 were higher than the previous period by 142% due to the increase in standby fees related to the new credit facility. Interest costs of $11.9 million are capitalized as part of STP-McKay Phase 1 for the quarter ended September 30, 2011.

Southern Pacific has recorded a Decommissioning Liability that represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The liability will be increased over time based on new obligations (wells drilled), constructing facilities, acquiring operations, or adjusting future estimates related to timing, discount rates and dollar amounts. Similarly, the liability can be reduced as actual abandonment costs are undertaken decreasing future obligations. The accretion charge of $0.1 million for the quarter ended September 30, 2011 represents the change in the estimated time value of the decommissioning liability. The increase in the accretion over the prior year is due to the additional liabilities created as STP-McKay Phase 1 is constructed. Currently the discounted liability is estimated at $24.6 million and will be accreted up to the estimated undiscounted liability of $56.3 million over the remaining economic life of the Company's assets.

Depletion and Depreciation

($ thousands except for per boe)	Three Months Ended September 30, 2011	2010	Change
Depletion and depreciation	**6,428**	8,379	(23%)
Per boe	**$18.46**	$22.09	(16%)

Depletion and depreciation expense of $6.4 million for the quarter decreased over the prior period in 2010 by 23% on an absolute basis and 16% on a per boe basis. The decrease was the result of reserve additions at Senlac.

The depletion on petroleum and natural gas properties is booked on a quarterly basis. For the quarter ended September 30, 2011, $390.6 million in oil sands properties (STP – McKay Phase 1) were excluded from the depletion calculation and $140.1 million of future development costs were added, based on proved plus probable reserves. Exploration and evaluation assets ("E&E") are not depleted.

Foreign Exchange

For the three months ended September 30, 2011 the foreign exchange loss was $6.7 million. The foreign exchange loss is the result of Southern Pacific completing a U.S. term loan facility during the prior year and the resulting weakening of the Canadian dollar compared to the U.S. dollar. The U.S. debt and resulting cash balance is re-valued into Canadian dollars at each reporting period. The change in the Canadian and U.S. foreign currency exchange rate and its resulting impact on the cash and debt balances being re-valued into Canadian dollars is recorded in the foreign exchange gain or loss.

Stock-Based Compensation

($ thousands except for per boe)	Three Months Ended September 30, 2011	2010	Change
Stock-based compensation	**913**	1,028	(11%)
Per boe	**$2.62**	$2.71	(3%)

Stock-based compensation costs recognize the non-cash fair value of stock options issued to directors, officers and employees of Southern Pacific. The estimated fair value of the stock options awarded is calculated using the Black-Scholes option pricing model. The value of the award is then recognized as an expense over the period from grant date to the date of vesting of the award.

During the quarter ended September 30, 2011 stock-based compensation was $0.9 million, compared to $1.0 million for the same period in 2010.

Income Taxes

Southern Pacific recorded a $3.3 million future tax expense for the quarter ended September 30, 2011 compared to a $1.1 million expense for the comparative quarter ended September 30, 2010.

The Company estimates it has approximately $487.5 million in tax pools before the deferred partnership income allocation as at September 30, 2011. Deferred partnership income is estimated to be $6.6 million, which would reduce the tax pools to $480.9 million. Both balances include

$143.8 million in non-capital tax losses which expire over time from 2014 to 2030. Southern Pacific is not currently taxable and does not expect to pay income taxes in fiscal 2012.

Net Income (Loss)

Southern Pacific recorded a loss of $0.7 million, or $nil per share, for the quarter ended September 30, 2011, compared to net income of $1.8 million, or $0.01 per share, in the same quarter of the prior year.

FUNDS FROM OPERATIONS

	Three Months Ended September 30,		
($ thousands except per boe and per share)	**2011**	2010	Change
Funds from operations	**10,675**	12,340	(13%)
Funds from operations per boe	**$30.66**	$32.53	(6%)
Funds from operations per basic and diluted share	**$0.03**	$0.04	(25%)

Funds from operations were $10.7 million for the quarter ended September 30, 2011, which is lower than the $12.3 million for the quarter ended September 30, 2010. On a per share basis, this equaled $0.03 versus $0.04, respectively. The decrease is attributable to lower production offset by slightly higher prices.

CAPITAL EXPENDITURES

The capital expenditures made on exploration and evaluation assets ("E&E") and property, plant and equipment ("PP&E") by Southern Pacific for the quarter ended September 30, 2011 and 2010 are summarized in the following table:

	Three Months Ended September 30,	
($ thousands)	**2011**	2010
McKay – Phase 1 and 2	**$98,887**	$6,429
Senlac	**7,236**	730
Red Earth	**1,485**	-
Other Exploration	**54**	28
Corporate	**350**	47
Conventional	**(2,109)**	67
Total	**$105,903**	$7,302

For the three months ended September 30, 2011 the Company incurred $105.9 million in capital expenditures. For STP-McKay Phase 1 and 2 the total expenditures of $98.9 million include capitalized interest of $11.9 million. The increase in McKay capital expenditures is related to the building of the SAGD facility which commenced in September of 2010. Senlac capital costs are up over the prior year quarter due to the drilling and completion of the Phase J well pairs. The Red Earth project did not exist in the first quarter of 2011 as it was acquired as part of the North Peace acquisition on November 23, 2010. Corporate capital increased over the prior year as the company incurred costs related to lease hold improvements and increased capitalized geological and geophysical costs. Conventional assets were sold in July 2011, resulting in a total capital reduction of $1.8 million.

Capital additions are recorded in both E&E assets and PP&E on the financial statements. The E&E assets, in the above additions, include STP- McKay Phase 2, Red Earth and other oil sands exploration lands. These projects are included in E&E as they have not yet obtained technical feasibility and commercial viability. PP&E assets include STP – McKay Phase 1, STP – Senlac and other corporate capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

As at September 30, 2011 Southern Pacific had working capital of $185.5 million. The Company also has an undrawn $30.0 million demand revolving operating credit facility with a syndicate of banks. The term of the credit facility is three years and extendible at the lenders' discretion. The credit facility is guaranteed by all of the Company's subsidiaries, and secured by a security interest in all of the existing and future assets of the Company and its subsidiaries. The security interest has first priority over all other creditors.

($ thousands)	**September 30, 2011**
Bank lines available	**$30,000**
Working capital	**185,485**
Capital resources available	**$215,485**

Southern Pacific believes it has sufficient capital to complete its STP-McKay Phase 1 project, fund budgeted capital expenditures at STP-Senlac and STP-Red Earth, execute other project developments at McKay and initiate other exploration activities from its available capital resources of $215.5 million and budgeted funds from operations over the next 12 months.

COMMITMENTS

Risk Management Activities

Oil and gas producers are exposed to fluctuations in commodity prices that are beyond the control of management. To protect cash flow for future capital programs, Southern Pacific has entered into the following commodity contracts to reduce the price risk of oil prices and natural gas purchases as of November 14, 2011:

Type	**Contract Term**	**Volume**	**Price**
Oil collar (WTI)	Jan 1, 2011 to Dec 31, 2011	1,500 bbl/day	US$70.00-$100.00
Oil collar (WTI)	Feb 1, 2011 to Dec 31, 2011	300 bbl/day	US$85.00-$105.00
Oil collar (WTI)	Apr 1, 2011 to Dec 31, 2011	400 bbl/day	US$90.00-$115.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	900 bbl/day	US$85.00-$115.75
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	500 bbl/day	US$90.00-$110.00
Oil collar (WTI)	Jan 1, 2012 to June 30, 2012	700 bbl/day	US$90.00-$115.05
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.10
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	750 bbl/day	US$80.00-$101.12
Oil collar (WTI)	July 1, 2012 to Dec 31, 2012	700 bbl/day	US$90.00-$100.00
Differential SWAP (WTI)	Jan 1, 2012 to Dec 31, 2012	1,000 bbl/day	WTI-US$17.25

Differential SWAP (WTI)	Jan 1, 2012 to Dec 31, 2012	1,000 bbl/day	WTI-US$16.25
Natural gas swap purchase (AECO)	July 1, 2011 to Dec 31, 2011	1,000 gj/day	$3.86
Natural gas swap purchase (AECO)	July 1, 2011 to Dec 31, 2011	1,000 gj/day	$3.84
Natural gas swap purchase (AECO)	Oct 1, 2011 to Dec 31, 2011	1,500 gj/day	$3.80
FX contract (US$)	Jan 1, 2011 to Dec 31, 2011	750 bbl/day	US$70 WTI, at 1.0620 USD/CAD
FX contract (US$)	October 1 to Dec 31, 2011	750 bbl/day	US$85 WTI, at 1.00 USD/CAD
FX contract (US$)	October 1 to Dec 31, 2011	750 bbl/day	US$85 WTI, at 1.0295 USD/CAD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.00 USD/CAD
FX contract (US$)	Jan 1, 2012 to Dec 31, 2012	750 bbl/day	US$85 WTI, at 1.0290 USD/CAD

Fixed Price Contracts

As of November 14, 2011 the Company committed to the following fixed price gas purchase contracts. The contracts are entered into to reduce the risk of gas price uncertainty, as gas is a significant input cost for the Senlac operations.

Type	Contract Term	Volume	Price
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.14
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$4.00
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	1,000 gj/day	$3.93

Leases

At September 30, 2011 the Company is committed to annual lease payments under the terms of a lease for its head office space and other office spaces:

($ thousands)	Amount
2012	$389
2013	409
2014	409
2015	273
Total	$1,480

Capital

At September 30, 2011, as part of normal operations relating to the construction of the STP-McKay Phase 1 SAGD project, the Company has entered into a total of $105.3 million in capital commitments to be paid over the next year.

Principal Payments

At September 30, 2011, the Company's required debt principal payments on the term loan and convertible debentures by fiscal year are as follows:

	Term loan	Convertible debentures	**Total**
2012	$2,143	$-	**$2,143**
2013	2,857	-	**2,857**
2014	2,857	-	**2,857**
2015	2,857	-	**2,857**
2016	272,841	172,500	**445,341**
Total	$283,555	$172,500	**$456,055**

OFF BALANCE SHEET ARRANGEMENTS

Southern Pacific has not entered into any off balance sheet arrangements at September 30, 2011.

TRANSACTIONS WITH RELATED PARTIES

During the quarter ended September 30, 2011 the Company incurred legal costs of $0.1 million (2010 - $0.1 million) with a law firm in which the corporate secretary is a partner. The legal costs incurred were in the normal course of operations and were based on the exchange value of the service provided, which approximates those amounts of consideration with third parties. Of the legal services provided, $0.1 million were included in accounts payable at September 30, 2011 (June 30, 2011 - $nil).

OUTSTANDING SECURITIES

Common Shares, Options and Warrants

There were 0.4 million common shares issued during the quarter ended September 30, 2011 at a weighted average exercise price of $0.51 per share from the exercise of stock options.

As at September 30, 2011, 24.2 million stock options were outstanding with an average exercise price of $1.25 and 0.2 million warrants were outstanding with an average exercise price of $1.01.

At November 14, 2011, the Company has 339.6 million common shares outstanding, 24.3 million stock options outstanding and 0.2 million warrants outstanding.

SELECTED QUARTERLY INFORMATION

The following information summarizes the financial results of the Company for each quarter during the past two fiscal years:

($ thousands except for per boe)	09/30/11 (1)	06/30/11 (1)	03/31/11 (1)	12/31/10 (1)	09/30/10 (1)	06/30/10 (2)	03/31/10 (2)	12/31/09 (2)
Production (boe/d)	**3,784**	4,915	3,664	4,359	4,123	$4,191	4,217	3,298
Oil and Gas revenues	**$20,769**	$30,721	$18,791	$23,514	$20,701	$20,673	$23,403	$17,561
Combined average price ($/boe)	**$59.65**	$68.68	$56.98	$58.63	$54.58	$54.21	$61.66	$57.88
Royalties ($/boe)	**$10.38**	$12.73	$9.93	$11.31	$8.85	$8.18	$11.10	$7.37
Operating costs ($/boe)	**$12.02**	$8.91	$11.59	$10.59	$9.56	$9.67	$11.50	$7.95
Operating netback ($/boe)	**$37.25**	$47.04	$35.46	$36.73	$36.17	$36.36	$39.06	$42.56
G&A expense ($/boe)	**$6.33**	$7.12	$7.96	$6.14	$3.30	$3.98	$3.11	$2.53
Funds from operations	**$10,675**	$17,942	$9,322	$12,268	$12,340	$11,837	$13,001	$11,386
Per share - basic	**$0.03**	$0.05	$0.03	$0.04	$0.04	$0.04	$0.06	$0.06
- diluted	**$0.03**	$0.05	$0.03	$0.04	$0.04	$0.04	$0.06	$0.06
Net income (loss)	**($697)**	$7,474	$112	$5,506	$1,795	($1,312)	$3,104	$7,089
Per share - basic	**($0.00)**	$0.02	$0.00	$0.02	$0.01	($0.00)	$0.01	$0.04
- diluted	**($0.00)**	$0.02	$0.00	$0.02	$0.01	($0.00)	$0.01	$0.04
Capital expenditures	**$105,903**	$109,039	$96,758	$74,317	$7,302	$42,380	$49,304	$91,052

(1) Quarterly information is presented in accordance with IFRS which the company adopted on June 30, 2010.
(2) Quarterly information is presented in accordance with Canadian GAAP.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the periods in which the annual and 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 period specified in securities legislation. All control systems by their nature have inherent limitations and, therefore, the Company's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that the objectives of the control systems are met.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO")have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company has, as its requirement under National Instrument 52-109, to evaluate design effectiveness and then test the effectiveness of its control environment during fiscal 2012, and has retained expert advisors to assist in the process. Based on this process, as of September 30, 2011 the CEO and CFO had concluded that its internal control over financial reporting was effective.

The Company's internal controls over financial reporting may not prevent or detect all errors, misstatements and fraud. The design of internal controls must also take into account resource constraints. A control system, including the Company's internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

NEW ACCOUNTING POLICIES

International Financial Reporting Standards ("IFRS")

In 2008, the CICA Accounting Standards Board confirmed that IFRS will replace Canadian GAAP for fiscal years beginning on or after January 1, 2011 for publicly accountable enterprises. Accordingly, the Company has commenced reporting on an IFRS basis in the current interim financial statements. Comparative information for periods from July 1, 2010 onwards has been restated in accordance with IFRS.

Transition to IFRS

With the conversion to IFRS, the Company completed an assessment of the impact of IFRS on internal controls over financial reporting ("ICOFR"). Based on this assessment no significant changes to the controls and procedures were required.

An assessment of the Company's infrastructure was also completed, primarily information technology and data systems. The assessment indicated that significant changes were necessary. As a result, the Company completed the transition to update its systems with a full conversion in the second quarter of fiscal 2011.

First-time Adoption of IFRS

IFRS 1 "First Time Adoption of IFRS" provides certain optional exemptions for entities adopting IFRS for the first time. The most significant elections taken are outlined here. IFRS 1 allows an entity that used full cost accounting under Canadian GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under Canadian GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under Canadian GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. The Company exercised this exemption and allocated the assets using proved and probable reserve volumes.

IFRS 2 "Share-based Payments" whereby stock options that vested prior to January 1, 2010 are not required to be retrospectively restated. Therefore, IFRS 2 requirements apply only to those options that were unvested at the transition date. Southern Pacific elected to apply this exemption.

In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets the Company has elected to re-measure the decommissioning liabilities in accordance with the IAS 37 standard. As allowed under IFRS 1, any difference between the IAS 37 amount and the carrying amount of the liabilities under Canadian GAAP at the date of transition was booked directly to retained earnings.

IFRS 1 does not allow hindsight to be used to create or revise previous estimates. Accordingly, the Company did not revise estimates previously made under Canadian GAAP, except where necessary, to reflect a change resulting from differences in accounting policy. A summary of all IFRS optional exceptions applied is outlined in Note 16 of the consolidated financial statements.

Significant IFRS impacts on financial reporting

The IFRS accounting policies are set forth in Note 3 of the unaudited consolidated financial statements for the period ended September 30, 2011. A detailed explanation of how the transition from Canadian GAAP to IFRS has impacted the Company's financial position, financial performance and cash flow, including the required reconciliations under IFRS 1, is also presented in the unaudited consolidated financial statements under Note 16.

The most significant impacts of IFRS upon conversion were within the areas of exploration and evaluation assets, depletion and depreciation expense, decommissioning liabilities, deferred income tax, share-based compensation, impairment and convertible debentures.

Exploration & Evaluation assets ("E&E")

IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas assets and has identified two significant differences in the accounting for assets under IFRS, one the treatment of pre-exploration costs and two the segregation of exploration and evaluation costs from property plant and equipment ("PP&E").

Pre-exploration costs are costs incurred before the Company obtains the legal right to explore an area. Under Canadian GAAP these costs were capitalized, while under IFRS, these costs must be expensed.

During the exploration and evaluation phase, the Company capitalized costs incurred for these projects under Canadian GAAP as part of PP&E. The Company, under IFRS, will capitalize these costs as exploration and evaluation assets until technical feasibility and commercial viability of the project has been determined. If not, the costs must be expensed to the statement of comprehensive income. If technical feasibility and commercial viability is obtained then the assets will be transferred to PP&E assets.

As a result of these differences $172.5 million in assets were transferred from PP&E to exploration and evaluation assets at July 1, 2010.

Depletion and depreciation expense

Canadian GAAP mandated that oil and gas properties were to be depleted on a unit of production method using remaining proved reserves on a cost center basis that was defined as a country. IFRS requires the depreciation method to best reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. IFRS requires that depletion be calculated on a significant component basis. Under IFRS the Company elected to deplete its oil and gas properties using the unit of production method but on a proved plus probable reserve basis. Assets, including STP-McKay Phase 1, that are yet to be brought into use or are not in the location and condition necessary for the assets to be capable of operating in the manner intended by management, are excluded from the depletion calculation.

The above changes resulted in a decrease to depletion expense and an increase in the carrying value of property, plant and equipment. This amount was $1.6 million at September 30, 2010 and $4.0 million at June 30, 2011.

Decommissioning liability

IAS 37 "Provisions, Contingent Liabilities and Contingent Assets", allows that the decommissioning liability be discounted using a risk free rate of 3.08% as at the transition date of June 30, 2010. Canadian GAAP required a credit-adjusted risk free rate which was substantially higher at 8.0%. As a result of using the lower risk free discount rate there was an increase of $3.7 million to the decommissioning liability with a corresponding increase to the Company's deficit at June 30, 2010.

IAS 37 also requires that the timing and amount of future expenditures are reviewed regularly, together with the interest rate used in discounting the cash flows and the carrying amount of the provision is adjusted accordingly. Under Canadian GAAP, a provision previously recognized was not revised for subsequent changes in the interest rates.

Deferred income tax
Under Canadian GAAP proceeds from the issuance of flow-through shares are recorded at their total value which typically includes a premium over the trading value of common shares. The tax basis of assets related to expenditures incurred to satisfy flow-through share obligations is reduced when the renunciation of the related tax pools occurs which then increased the deferred income tax liability and reduced share capital. Under IFRS, the premium over the fair market value of "regular" common shares is not recorded to share capital but set up as a deferred obligation upon issuance of flow-through shares. As the tax deductions associated with the flow-through expenditures are renounced a deferred income tax liability is estimated based on the amount of deferred income taxes now payable by the Company. As the deferred income tax liability is recorded it is offset to the deferred obligation with any differences recognized in profit or loss. There is no impact to share capital on renunciation of flow-through shares.

The above accounting policy change, upon transition to IFRS, increased the share capital of the Company by approximately $2.0 million at July 1, 2010. This policy did not impact the financial statements as at and for the periods ended June 30, 2011.

Share issue costs were treated as a temporary difference under Canadian GAAP but under IFRS these are treated as an adjustment to share capital when the tax rate changes. At transition date this adjustment was $0.1 million.

The convertible debentures liability and equity portions were adjusted for the value of a redemption option. The deferred tax impact on the equity component was a permanent tax difference under previous GAAP however, under IFRS this is a temporary difference. This adjustment has reduced the equity portion of the convertible debenture and increased deferred tax liability by $9.3 million for the year ended June 30, 2011. This change also reduced the deferred income tax expense for the year ended June 30, 2011. The expense was reduced because the temporary difference of $9.3 million is reversed over time, as the debt portion of the convertible debenture is accreted. This adjustment was $0.7 million.

Deferred income tax calculated according to IFRS is substantially similar to Canadian GAAP and arises from the differences in the accounting and tax bases of assets and liabilities. Where balances have changed due to IFRS differences, the amount of deferred income tax liability will be impacted.

Under Canadian GAAP, deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

Under Canadian GAAP, Saskatchewan resource payments were classified as a tax however under IFRS they are now classified as a royalty and netted to petroleum revenue.

Share based compensation
Under Canadian GAAP, the company recognized an expense related to share-based payments on a straight-line basis and did not include an estimate of forfeitures. Under IFRS the company is required to recognize the expense over the individual vesting periods for the graded vesting awards and to estimate a forfeiture rate. At transition date this resulted in a $0.2 million decrease to contributed surplus and an increase to retained earnings. At September 30, 2010 this amount was $0.1 million and at June 30, 2011 this amount was $0.3 million.

Impairment
Under IFRS impairment is done by a Cash Generating Unit, defined as the smallest group of assets that produce independent cash flows rather than on a country level. The conventional oil and gas CGU was impaired at June 30, 2011 for $4.5 million. The impairment was the result of the conventional assets, under IFRS, being subject to the impairment test on a standalone basis rather than part of a full cost pool under Canadian GAAP.

Convertible Debentures
Under IFRS the fair value of the liability portion includes a redemption option which increased the value of the liability and decreased the value of the equity portion by $5.0 million for the period ended June 30, 2011. The option was not separated as it was considered closely related to the host contract.

CRITICAL ACCOUNTING ESTIMATES

Oil and Gas Reserves

The process of estimating reserves and contingent resources is complex. It requires significant judgments and decisions based on geological, geophysical, engineering and economic data. Reserve and contingent resource estimates are based on current production forecasts, prices and economic conditions. These estimates may change substantially as additional data from ongoing development and production activities become available and as economic conditions impact oil and gas prices and costs. Southern Pacific's properties are evaluated annually by independent petroleum engineering consultants.

Exploration and Evaluation of Assets

Exploration and evaluation costs associated with the Company's oil sands activities are capitalized as either tangible or intangible exploration and evaluation assets, according to the nature of the assets acquired. These costs are accumulated in E&E pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when reserves are determined to exist. The determination of reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairment of Property and Equipment

Intangible exploration and evaluation assets are assessed for impairment when they are reclassified into PP&E, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The carrying value of the Company's PP&E assets are reviewed for indication of impairment at each reporting date. The PP&E assets are aggregated into cash-generating units ("CGU's") for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. If impairment is indicated, the CGU is written down to the greater of the value in use or fair value less costs to sell. Each calculation is dependent on a number of estimates including reserves, production rates, prices, future costs and other relevant assumptions. As a result, these estimates are subject to significant management judgment.

Withheld Costs
Certain costs included in major project developments related to the Company's oil sands assets classified in PP&E may be excluded from costs subject to depletion. These costs are excluded until the assets are determined to be operating in the manner intended by management which requires judgment.

Decommissioning Obligations
When Southern Pacific has drilled core holes, it has properly abandoned them within the drilling program and therefore, no decommissioning obligation has been booked on its core hole program. The Company is required to provide for future removal and restoration costs on its oil and gas assets. Southern Pacific estimated these costs in accordance with existing laws, contracts or other policies. The fair value of the liability for the decommissioning obligations is recorded in the period in which it is to be incurred and discounted to its present value using a risk free rate. The offset to the liability is recorded in the carrying amount of property and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded and any difference is booked to profit or loss.

Depletion Expense
Depletion and depreciation of petroleum and natural gas properties, including the Company's oil sands facilities, are calculated using the unit-of-production method based upon the production volumes and/or the facilities productive capacity, before royalties, in relation to the estimated total proved and probable petroleum and natural gas reserves as estimated by independent engineers. In determining costs subject to depletion, Southern Pacific also includes estimated future costs to be incurred in developing proved and probable reserves. The determination of future development costs, reserves, and productive capacity are all subject to significant judgments and estimates.

Stock-Based Compensation
The Company uses the fair value method for valuing stock option grants. The fair value of each option is estimated on the date of the grant using the Black-Scholes option pricing model. This model requires Southern Pacific's management to make estimates and assumptions for the expected volatility, risk-free rate and forfeiture rate. A zero dividend is used as the Company does not issue dividends. The volatility is a calculation based on the past trading history of the Company's shares, the risk-free rate is obtained from the Bank of Canada and the forfeiture rate is based on past activity. An increase in dividends or forfeiture rate would decrease the option expense and an increase in the volatility or risk-free rate would increase the option expense.

Income Tax
The determination of the Company's income tax and other liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual liability may differ from that estimated and recorded by management.

Risk Management Contracts

The Company may utilize risk management contracts to manage its currency and interest rate exposures. The financial instruments are not issued for trading or speculative purposes. The fair values of risk management contracts are estimated at the balance sheet date based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecasted interest rates, foreign exchange rates and commodity prices expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the risk management contracts.

BOE PRESENTATION

The use of barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 barrel is based on an energy equivalent conversion method primarily applicable at the burner tip and is not intended to represent a value equivalency at the wellhead.

NOTE REGARDING NON-IFRS MEASURES

This MD&A includes references to certain financial measures, as described below, which do not have standardized meanings prescribed by IFRS. Because these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The Company uses these measures to evaluate its performance. Investors are cautioned that these non-IFRS measures should not be construed as an alternative to the measures calculated in accordance with IFRS as, given their non-standardized meanings; they are unlikely to be comparable to similar measures presented by other issuers. The term "operating netback" is defined as petroleum and natural gas sales less royalties and less operating and transportation costs. The term "funds from (used in) operations" is defined as the cash flow from operating activities before the change in non-cash working capital and abandonment expenditures and should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net income (loss) as determined in accordance with IFRS as an indicator of performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. A summary of this reconciliation is as follows:

	Three Months Ended September 30,	
($ thousands)	**2011**	2010
Cash provided by operations	**$11,143**	$10,120
Change in non-cash working capital	**(468)**	2,218
Cash decommissioning expenditures	**-**	2
Funds from operations	**$10,675**	$12,340

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A may constitute forward-looking statements. These statements relate to future events or Southern Pacific's future performance. All statements, other than statements of historical fact, may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "plan," "continue," "estimate," "expect," "may," "will," "project," "predict," "propose," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Forward-looking statements included in this MD&A should not be unduly relied upon by investors as actual results may vary. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- capital expenditure programs;
- development of resources;
- treatment under governmental regulatory and taxation regimes;
- expectations regarding the Company's ability to raise capital;
- expenditures to be made by the Company to meet certain work commitments; and,
- work plans to be conducted by the Company.

With respect to the forward-looking statements listed above and contained in this MD&A, the Company has made assumptions regarding, among other things:

- the legislative and regulatory environment;
- the impact of increasing competition;
- unpredictable changes to the market prices for oil and natural gas;
- costs related to the development of the Company’s oil and gas properties (that they will remain consistent with historical experience);
- the anticipated results of exploration activities; and,
- the Company's ability to obtain additional financing on satisfactory terms.

Southern Pacific’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

- volatility in the market prices for oil and natural gas;
- uncertainties associated with estimating resources;
- geological, technical, drilling and processing problems;
- liabilities and risks, including environmental liabilities and risks, inherent in oil and natural gas operations;
- fluctuations in currency and interest rates;
- incorrect assessments of the value of acquisitions;
- unanticipated results of exploration activities;
- competition for, among other things, capital, reserves, undeveloped lands and skilled personnel; and,
- unpredictable weather conditions.

The Company’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth above. These factors include the risks discussed in the Company’s Annual Information Form for the year ended June 30, 2011, which include, without limitation, the inherent risks involved in a developmental stage oil sands extraction enterprise.

Southern Pacific faces uncertainties, including those associated with resource definition, the timeline to production of STP-McKay Phase 1, the possibility of cost overruns or unanticipated costs and expenses, regulatory approvals, changes to royalty regimes, fluctuating commodity prices and currency exchange rates and the ability to access sufficient capital from external sources to finance future development. As a consequence, actual results may differ, and may differ materially, from those anticipated in the forward-looking statements. The reader is cautioned not to place undue reliance on these forward-looking statements as there can be no assurance that such plans, intentions or expectations upon which they are based will occur. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this MD&A are made as of the date of this MD&A and state no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise, expect as required by applicable securities laws.

RISK FACTORS

The Company's business consists of the exploration and development of oil and gas properties in Western Canada. There are a number of inherent risks associated with the exploration for and development and production of oil and gas reserves. Many of these risks are beyond the control of the Company. These risk factors are described in the Company’s Annual Information Form filed on SEDAR on September 21, 2011 at www.sedar.com and available on Southern Pacific’s website at www.shpacific.com. Please refer to this document for more information.