SOUTHERN PACIFIC
RESOURCE CORP.

Management's Discussion and Analysis for the

Three and Six Months Ended December 31, 2011

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." 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.

In this Management's Discussion and Analysis ("MD&A"), 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 "second quarter 2012" in this document refer to the three month financial period ended December 31, 2011. References to "first quarter 2012" in this document refer to the three month financial period ended September 30, 2011. References to "second quarter 2011" in this document refer to the comparative three month financial period ended December 31, 2010.

The following 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 six months ended December 31, 2011. This MD&A is dated February 9, 2012. The financial statements and financial data contained in this MD&A are part of the Company's first year of 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. As such, the comparative periods have 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").

OVERALL PERFORMANCE

Highlights for the quarter ended December 31, 2011 include the following:

- Continued strong execution on the construction of STP-McKay Phase 1 Thermal Project ("STP-McKay Phase 1"). Total project cost estimate is currently $440 million. The original budget for the project was $450 million. The Company continues to forecast first steam towards the end of the second quarter of calendar 2012, with oil production commencing three to four months after first steam;
- Achieved funds from operations of $11.2 million for the quarter compared to $12.3 million in the second quarter of 2010. Strong oil prices, low heavy oil differentials and weak natural gas pricing helped maintain cash flow, despite the second quarter being a lower production cycle for the STP-Senlac project;
- Increased its Proven plus Probable ("2P") reserves by 30% to 234 million barrels of bitumen as a result of the additional plant capacity from Phase 2 which permitted additional contingent resources to be reassigned to a 2P category. Correspondingly, the before tax net present value discounted at 10% increased by $0.6 billion to $1.7 billion within the 2P category, reflecting the acceleration of cash flow from previously booked reserves that were constrained by the Phase 1 capacity of 12,000 bbl/d;

- Averaged overall production from STP-Senlac of 3,249 barrels per day (“bbl/d”) for the quarter, bringing the total average production for the 2011 calendar year to 3,903 bbl/d. The second quarter production was about 15% below guidance due to a drilling rig delay on the Phase J steam assisted gravity drainage (“SAGD”) well pairs. However, the first of three Phase J SAGD well pairs was placed on production on December 29, 2011 and a second well pair was brought on production on January 14, 2012. Total average production for January was approximately 4,200 bbl/d and the field exited January with a seven day average of 4,708 bbl/d. The facility is now fully utilized with a third Phase J SAGD well pair on standby, ready to be activated as plant capacity becomes available; 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, increasing the total STP-McKay capacity to 36,000 bbl/d.

OUTLOOK

Southern Pacific remains focused on the construction and operation of STP-McKay Phase 1. The 12,000 bbl/d 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 $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.

Construction has advanced significantly over the past quarter on STP-McKay Phase 1. All of the major pieces of equipment have been installed, including the cogenerators, boilers, produced fluids treatment facilities, and the water treatment package. All of the piperack modules have also been installed. All nine site erected tanks have been mechanically completed. Final minor equipment modules will continue to arrive weekly in February with the final few modules arriving in March 2012.

Of particular note, the STP operations office and the 84 person operations camp were completed. In January, Southern Pacific’s operations team relocated from its temporary offices in Calgary into the plant site camp and offices. The STP-McKay project will be operated utilizing a 46 person team, rotating through four shifts. The Company currently has 40 of its staff hired, including all senior personnel. Over the next several months, the operating staff will be working on site, finalizing all operational procedures, developing best practices based on their experience with other SAGD projects, and ensuring the transfer from construction personnel and start up occurs as smoothly as possible.

Another area of focus that the Company is proud to report on is health and safety. As of December 31, 2011, approximately 820,000 hours have been logged on the work site since construction started in December 2010. In that period, only one minor loss time accident has occurred. This is well below industry averages in terms of loss time frequency. The Company wishes to extend our appreciation to all staff, consultants and contractors on site who have made safety a priority through 2011, and who have committed to continue maintaining safety as a priority through the completion, start up and operation of this facility.

From a timing perspective, Southern Pacific expects first steam to the SAGD well pairs will occur on schedule towards the end of the second quarter of calendar 2012 with first oil production to occur three to four months from the first steam date.

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 worked on this application for nine months and the contents of this document and all appendices are now located on Southern Pacific's website. The filing of a complete application for the project marks a significant milestone in Southern Pacific's growth. As a result of this filing, Southern Pacific increased its 2P reserves by 30% to 234 million barrels of bitumen. The filing of the Phase 2 application resulted in an increase in the Company's 2P reserves, which have now been classified under the combined process capacity of 36,000 bbl/d within the project area. Correspondingly, the before tax net present value discounted at 10% increased by $0.6 billion to $1.7 billion within the 2P category, reflecting the acceleration of cash flow from previously booked reserves that were constrained by the Phase 1 capacity of 12,000 bbl/d. The Company anticipates regulatory approval to occur within 18 to 24 months based on its previous Phase 1 approval which occurred in 15 months.

The Company completed drilling and tie-in of Phase J at Senlac in December 2011, which consists of three SAGD well pairs. Circulation steam on the first well pair commenced in mid December and first oil was produced in from the well pair on December 29. The on-stream date was delayed about 45 days due to a delay in the drilling rig arriving on site. The second well pair was brought on production on January 14, 2012. With these two additional well pairs on stream, the project averaged over 4,200 bbl/d for January and exited the month with a seven day average of 4,708 bbl/d. The facility is now fully utilized with a third Phase J well pair on standby, ready to be activated as plant capacity becomes available. The facility underwent a bi-annual turnaround in mid 2011 and all equipment is in very good condition, providing expectation of high load factors for 2012. Plans to drill and equip the next three SAGD well pairs (Phase K) are now underway, with an expectation to have Phase K ready for operation in the fourth quarter of calendar 2012.

Southern Pacific continues to explore the potential of its STP-Red Earth Thermal Project ("STP-Red Earth") in the Peace River oil sands. Testing on the 1,000 bbl/d pilot project occurred over the last half of calendar 2011 on three existing wellbores drilled prior to Southern Pacific taking ownership. Southern Pacific used these existing wellbores to test three different configurations of Cyclic Steam Stimulation (CSS). The results of this initial pilot testing program are currently being analyzed and modeled. The Company expects to finalize its future development plans for Red Earth in the second quarter of calendar 2012.

RESULTS OF OPERATIONS

Production

	Three Months Ended December 31,			Six Months Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Heavy oil (bbl/day)	**3,224**	4,337	(26%)	**3,501**	4,210	(17%)
Natural gas (mcf/day)	**146**	134	9%	**92**	190	(52%)
Total (boe/day)	**3,249**	4,359	(25%)	**3,517**	4,242	(17%)

Heavy oil production for the quarter ended December 31, 2011 averaged 3,224 barrels of oil equivalent per day (boe/day), a decrease of 26% over the same period in 2010. The decrease is attributable to the delay of bringing the Phase J well pairs on production. The first of these well pairs was placed on production on December 29, 2011 and a second well pair was brought on production on January 14, 2012. Total average production for January was approximately 4,200 bbl/d and the field exited January with a seven day average of 4,708 bbl/d. Natural gas production was comparable quarter over quarter.

For the six months ended December 31, 2011 the heavy oil production averaged 3,501 boe/d, a 17% decrease from the same period in 2010. The decrease is attributable to natural declines that are offset with the Phase J well pairs now on production, as discussed above. The natural gas declines are the result of the sale of non-core assets in the first quarter of 2012.

Product Prices

	Three Months Ended December 31,			Six Months Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Heavy oil ($ per bbl)	**73.84**	58.75	26%	**66.31**	56.85	17%
Natural gas ($ per mcf)	**3.09**	4.36	(29%)	**3.21**	4.04	(21%)
Combined average ($ per boe)	**73.54**	58.63	25%	**66.08**	56.66	17%

The heavy oil price received by Southern Pacific was $73.84 per bbl for the three months ended December 31, 2011, 26% higher than the same quarter in the prior year. The increase in the heavy oil price for the second quarter of 2012 is largely attributable to the increase in the WTI crude oil price and a slight decrease in the heavy oil differential. Southern Pacific has entered into commodity hedging contracts to mitigate fluctuations in commodity prices as outlined under Risk Management Activities and Commitments section below. The decrease in natural gas pricing is expected given current natural gas markets.

For the six months ended December 31, 2011 the heavy oil price increased 17% over the prior year to $66.31 per bbl. The increase was due to higher WTI pricing offset with slightly higher heavy oil differentials. Natural gas prices decreased for the six months ended December 31, 2011 consistent with natural gas market conditions.

Operating Netbacks

	Three Months Ended December 31,			Six Months Ended December 31,		
($ per boe)	**2011**	2010	Change	**2011**	2010	Change
Combined average	**73.54**	58.63	25%	**66.08**	56.66	17%
Royalties	**(10.86)**	(11.31)	(4%)	**(10.60)**	(10.11)	5%
Operating costs	**(11.26)**	(10.59)	6%	**(11.67)**	(10.09)	16%
Operating netback	**51.42**	36.73	40%	**43.81**	36.46	20%

Operating netbacks for the quarter and six months ended December 31, 2011 increased by 40% and 20% respectively, over the same periods in the prior year. This increase is primarily due to the higher average combined product prices received, offset by higher operating costs.

Oil and Gas Revenue

($ thousands)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
Heavy oil	**21,952**	23,457	(6%)	**42,706**	44,071	(3%)
Natural gas	**42**	57	(26%)	**57**	144	(60%)
Total oil and gas revenue	**21,994**	23,514	(7%)	**42,763**	44,215	(3%)

Total oil and gas revenue for the quarter and six months ended December 31, 2011 was $22.0 million and $42.8 million respectively. The decrease from the comparative prior periods of 7% and 3% is due to lower production volumes offset by higher realized heavy oil pricing. The natural gas revenue decreased as a result of the sale of the non-conventional assets on July 15, 2011 and reduced natural gas pricing.

Risk Management Contracts

($ thousands)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
Unrealized (loss)	**(7,813)**	(1,171)	567%	**(2,294)**	(1,002)	129%
Realized (loss) gain	**(53)**	95	(156%)	**394**	24	1,542%
Risk management contracts	**(7,866)**	(1,076)	631%	**(1,900)**	(978)	94%

For the quarter and six months ended December 31, 2011, Southern Pacific recorded an unrealized loss on risk management contracts of $7.8 million and $2.3 million respectively, compared to an unrealized loss of $1.2 million and $1.0 million for the same periods in 2010. The unrealized losses are largely attributable to a gradual increase in the WTI oil price over both the three and six month periods ended December 31, 2011 that decreased the value of the risk management contracts. The realized loss and gain for the quarter and six months ended December 31, 2011 are largely attributable to the fixed natural gas price contracts and foreign exchange hedges. The realized gains or losses on the risk management contracts represent actual cash received or paid by Southern Pacific as its hedged price either exceeded or was less than the market price. 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

($ thousands except for % and per boe)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
Royalties	**2,870**	4,139	(31%)	**6,129**	7,146	(14%)
Provincial resource surcharges	**377**	398	(5%)	**733**	747	(2%)
	3,247	4,537	(28%)	**6,862**	7,893	(13%)
% of oil and gas revenue	**14.8%**	19.3%	(23%)	**16.0%**	17.9%	(11%)
Per boe	**$10.86**	$11.31	(4%)	**$10.60**	$10.11	5%

Royalties for the quarter ended December 31, 2011 were $3.2 million, compared to $4.5 million for the same quarter in 2010. The royalties represented 14.8% of total petroleum and natural gas revenue compared to 19.3% in the same quarter of 2010. On a percentage, absolute and per barrel basis, royalties have decreased due to higher capital spending and operating costs relative to the prior year's quarter. The royalty rates at Senlac are on a sliding scale dependent upon the level of capital spending and operating costs. 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 are determined as a fixed percentage of provincial resource revenues generated from the Company's Senlac property.

Royalties for the six months ended December 31, 2011 were $6.9 million compared to $7.9 million for the same period in 2010 which represented 16% and 18% respectively of the total petroleum and natural gas revenue. Again, the decrease in the royalty rates is attributable to higher capital spending and operating costs.

Operating Costs

	Three Months Ended December 31,			Six Months Ended December 31,		
($ thousands except for per boe)	**2011**	2010	Change	**2011**	2010	Change
Other operating costs	**2,255**	2,899	(22%)	**5,268**	5,495	(4%)
Natural gas costs	**1,112**	1,350	(18%)	**2,284**	2,380	(4%)
Operating costs	**3,367**	4,249	(21%)	**7,552**	7,875	(4%)
Per boe	**$11.26**	$10.59	6%	**$11.67**	$10.09	16%

Other operating costs for the quarter and six months ended December 31, 2011 decreased by 22% and 4% respectively, compared to the same periods in 2010. The decrease in the quarter is attributable to fewer workover costs at Senlac. For the six months ended December 31, 2011 and 2010 the operating costs are comparable.

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 its natural gas price risk by selectively hedging, or purchasing fixed price contracts, a portion of its natural gas purchases throughout the year. For the quarter and six months ended December 31, 2011 the natural gas costs decreased by 18% and 4% respectively compared to the same periods in 2010. The decrease is the result of lower natural gas prices.

In total, operating costs were $3.4 million for the quarter ended December 31, 2011, compared to $4.2 million for the same quarter in 2010. For the six months ended December 31, 2011 total operating costs were 4% less than the prior year. On a per barrel basis for the quarter ended December 31, 2011 the operating costs increased to $11.26 from $10.59 in the prior quarter of 2010 and for the six months ended December 31, 2011 the operating costs increased to $11.67 from $10.09 in 2010. The increase in both periods was the result of lower production.

Exploration and Evaluation Expenses

Exploration and evaluation expenses for the second quarter 2011 were $nil compared to $0.1 million for the second quarter 2010. For the six months ended December 31, 2011 the exploration and evaluation expenses were $nil compared to $0.3 million for the same period in 2010. In both periods the exploration and evaluation expenses relate to lease expiries on undeveloped lands.

General and Administrative Expenses

($ thousands except for per boe)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
General and administrative expenses	**3,752**	2,461	52%	**5,957**	3,714	60%
Per boe	**$12.55**	$6.14	105%	**$9.21**	$4.76	93%

General and administrative expenses for the quarter and six months ended December 31, 2011 are 52% and 60% higher respectively compared to the same periods in 2010. The increase is due to additional personnel hired and administration costs required for STP-McKay Phase 1 that is under construction and yearly discretionary bonuses.

Finance Expenses

($ thousands except for per boe)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
Interest and financing	**137**	94	46%	**270**	149	81%
Accretion	**20**	19	5%	**55**	25	120%
	157	113	51%	**325**	174	201%
Per boe	**$0.53**	$0.28	89%	**$0.50**	$0.22	125%

Finance expenses for the quarter and six months ended December 31, 2011 were higher than the previous period by 46% and 81% respectively, due to the increase in standby fees related to the new credit facility. Interest costs of $12.3 million and $24.2 million are capitalized as part of STP-McKay Phase 1 for the quarter ended and six months December 31, 2011 respectively.

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 including: 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 December 31, 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 $33.7 million and will be accreted up to the estimated undiscounted liability of $75.6 million over the remaining economic life of the Company's assets.

Depletion and Depreciation

($ thousands except for per boe)	Three Months Ended December 31, 2011	2010	Change	Six Months Ended December 31, 2011	2010	Change
Depletion and depreciation	**5,746**	7,553	(24%)	**12,174**	15,932	(24%)
Per boe	**$19.22**	$18.83	2%	**$18.81**	$20.41	(8%)

Depletion and depreciation expense for the quarter and six months ended December 31, 2011 decreased over the prior periods in 2010 by 24%. The decrease was the result of reserve additions in late fiscal 2011 at Senlac and lower production levels.

The depletion on petroleum and natural gas properties is booked on a quarterly basis. For the quarter ended December 31, 2011, $487.4 million in oil sands properties (STP-McKay Phase 1) were excluded from the depletion calculation and $128.0 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 and six months ended December 31, 2011 the Company had a foreign exchange gain of $2.6 million and a loss of $4.0 million, respectively. The foreign exchange gain or loss is the result of Southern Pacific completing a U.S. term loan facility during the prior year and the resulting changes in the Canadian dollar compared to the U.S. dollar. The U.S. debt and resulting cash balance has been 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 stated in Canadian dollars is recorded as a foreign exchange gain or loss. For the three months ended December 31, 2011 the foreign exchange gain was the result of a strengthening Canadian dollar from $1.039 CAD/USD at September 30, 2011 to $1.017 CAN/USD at December 31, 2011. For the six months ended the foreign exchange loss was largely attributable to a weakening Canadian dollar which moved from $0.964 CAN/USD at June 30, 2011 to the $1.017 CAN/USD at December 31, 2011.

Stock-Based Compensation

	Three Months Ended December 31,			Six Months Ended December 31,		
($ thousands except for per boe)	**2011**	2010	Change	**2011**	2010	Change
Stock-based compensation	**949**	554	71%	**1,862**	1,582	18%
Per boe	**$3.18**	$1.38	130%	**$2.88**	$2.03	42%

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 and six months ended December 31, 2011 stock-based compensation was $0.9 million, and $1.9 million compared to $0.6 million and $1.6 million for the same periods in 2010. The increase over the prior year is the result of new stock options being issued as personnel are hired to drive the STP-McKay Phase 1 project forward.

Income Taxes

Southern Pacific recorded a $0.7 million deferred tax recovery and a $2.6 million deferred tax expense for the quarter and six months ended December 31, 2011 compared to a $0.9 million and $2.0 million deferred tax expense for the comparative quarter and six months ended December 31, 2010.

The Company estimates it has approximately $591.3 million in tax pools before the deferred partnership income allocation as at December 31, 2011. Deferred partnership income is estimated to be $21.3 million, which would reduce the tax pools to $570.0 million. Both balances include $144.0 million in non-capital tax losses which expire over time from 2014 to 2031. Southern Pacific is not currently taxable and does not expect to pay income taxes in fiscal 2012.

Net Income (loss)

Southern Pacific recorded net income of $0.2 million, or $0.00 per share, for the quarter ended December 31, 2011, compared to net income of $5.5 million, or $0.02 per share, for same quarter in 2010. For the six months ended December 31, 2011 the Company recorded a loss of $0.5 million, or $0.00 per share, compared to net income of $7.3 million in the prior period.

FUNDS FROM OPERATIONS

($ thousands except per boe and per share)	Three Months Ended December 31,			Six Months Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Funds from operations	**11,248**	12,268	(8%)	**21,923**	24,608	(11%)
Funds from operations per boe	**$37.63**	$30.59	23%	**$33.88**	$31.53	7%
Funds from operations - basic	**$0.03**	$0.04	(25%)	**$0.06**	$0.08	(25%)
Funds from operations - diluted	**$0.03**	$0.04	(25%)	**$0.06**	$0.07	(14%)

Funds from operations were $11.2 million for the quarter and $21.9 million for the six months ended December 31, 2011, which is lower than the $12.3 million for the quarter and $24.6 million for the six months ended December 31, 2010. The decrease is attributable to lower production offset by slightly higher prices, lower royalties and operating costs.

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 six months ended December 31, 2011 and 2010 are summarized in the following table:

($ thousands)	Three Months Ended December 31, **2011**	2010	Six Months Ended December 31, **2011**	2010
McKay – Phase 1 and 2	**$87,404**	$46,830	**$186,291**	$53,259
Senlac	**10,264**	7,545	**17,500**	8,275
Red Earth	**1,015**	109	**2,500**	109
Other Exploration	**4**	109	**58**	137
Corporate	**285**	414	**635**	461
Conventional	**-**	142	**(2,109)**	210
Acquisition	-	19,168	-	19,168
Total	**$98,972**	$74,317	**$204,875**	$81,619

For the quarter and six months ended December 31, 2011 the Company incurred $99.0 million and $204.9 million in capital expenditures. For STP-McKay Phase 1 and 2 the total expenditures for the quarter and six months ended December 31, 2011 of $87.4 million and $186.3 million include capitalized interest of $12.3 million and $24.2 million respectively. 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 leasehold improvements and increased capitalized geological and geophysical costs. Conventional assets were sold in July 2011, resulting in a total capital reduction of $2.1 million for the six months ended December 31, 2011. The acquisition capital of $19.2 million is the result of the North Peace acquisition that occurred in the second quarter of 2011.

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.

Subsequent to December 31, 2011 economic viability and technical feasibility was established in regards to a portion of the STP-McKay Phase 2 assets. As a result, related costs of $66.9 million were transferred from E&E to PP&E.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2011 Southern Pacific had working capital of $88.6 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)	**December 31, 2011**
Bank lines available	**$30,000**
Working capital	**88,608**
Capital resources available	**$118,608**

Southern Pacific believes it has sufficient capital to complete its STP-McKay Phase 1 project, fund budgeted capital expenditures at STP-Senlac, execute other project developments at McKay and other exploration activities from its available capital resources of $118.6 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 February 9, 2012:

Type	Contract Term	Volume	Price
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	500 bbl/day	WTI-US$16.95
FX contract (US$)	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

Fixed Price Contracts

As of February 9, 2012 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
Natural gas fixed purchase (AECO)	Jan 1, 2012 to Dec 31, 2012	500 gj/day	$3.86
Natural gas fixed purchase (AECO)	July 1, 2012 to Dec 31, 2012	2,000 gj/day	$2.96

Leases
At December 31, 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	$327
2013	409
2014	409
2015	273
Total	$1,418

Capital
At December 31, 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 $45.3 million in capital commitments to be paid over the next year.

Principal Payments
At December 31, 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	$1,398	$ -	$**1,398**
2013	2,797	-	**2,797**
2014	2,797	-	**2,797**
2015	2,797	-	**2,797**
2016	267,090	172,500	**439,590**
Total	$276,879	$172,500	**$449,379**

OFF BALANCE SHEET ARRANGEMENTS
Southern Pacific has not entered into any off balance sheet arrangements at December 31, 2011.

TRANSACTIONS WITH RELATED PARTIES
During the quarter and six months ended December 31, 2011 the Company incurred legal costs of $0.2 million (2010 - $0.2 million) and $0.3 million (2010 - $0.2 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, $nil were included in accounts payable at December 31, 2011 (June 30, 2011 - $nil).

OUTSTANDING SECURITIES
Common Shares, Options and Warrants
There were 0.4 million and 0.8 million common shares issued during the quarter and six months ended December 31, 2011 at a weighted average exercise price of $0.50 per share from the exercise of stock options.

As at December 31, 2011, 24.2 million stock options were outstanding with an average exercise price of $1.26 and 0.2 million warrants were outstanding with an average exercise price of $1.01.

At February 9, 2012, the Company has 340.0 million common shares outstanding, 24.4 million stock options outstanding and 0.1 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)	12/31/11 (1)	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)
Production (boe/d)	3,249	3,784	4,915	3,664	4,359	4,123	4,191	4,217
Oil and gas revenues	$21,994	$20,769	$30,721	$18,791	$23,514	$20,701	$20,673	$23,403
Combined average price ($/boe)	$73.54	$59.65	$68.68	$56.98	$58.63	$54.58	$54.21	$61.66
Royalties ($/boe)	$10.86	$10.38	$12.73	$9.93	$11.31	$8.85	$8.18	$11.10
Operating costs ($/boe)	$11.26	$12.02	$8.91	$11.59	$10.59	$9.56	$9.67	$11.50
Operating netback ($/boe)	$51.42	$37.25	$47.04	$35.46	$36.73	$36.17	$36.36	$39.06
G&A expense ($/boe)	$12.55	$6.33	$7.12	$7.96	$6.14	$3.30	$3.98	$3.11
Funds from operations	$11,248	$10,675	$17,942	$9,322	$12,268	$12,340	$11,837	$13,001
Per share - basic	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04	$0.04	$0.06
- diluted	$0.03	$0.03	$0.05	$0.03	$0.04	$0.04	$0.04	$0.06
Net income (loss)	$224	($697)	$7,474	$112	$5,506	$1,795	($1,312)	$3,104
Per share - basic	($0.00)	($0.00)	$0.02	$0.00	$0.02	$0.01	($0.00)	$0.01
- diluted	($0.00)	($0.00)	$0.02	$0.00	$0.02	$0.01	($0.00)	$0.01
Capital expenditures	$98,972	$105,903	$109,039	$96,758	$74,317	$7,302	$42,380	$49,304

(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 December 31, 2011 the CEO and CFO had concluded that its internal control over financial reporting is 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 17 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 December 31, 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 17.

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 $3.0 million at December 31, 2010.

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 July 1, 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 July 1, 2010. At December 31, 2010 a rate of 3.32% was used with an increase to the decommissioning liability of $4.2 million.

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.

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 December 31, 2010 the decrease to contributed surplus was $0.4 million.

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.

Cash Generating Units
Oil and natural gas assets are grouped into CGU's that have been identified as being the smallest identifiable group of assets that generate cash flows, that are independent of cash flows of other assets or groups of assets. The determination of these CGU's was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

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 December 31,		Six Months Ended December 31,	
($ thousands)	**2011**	2010	**2011**	2010
Cash provided by operations	**$11,838**	$3,285	**$22,981**	$13,403
Change in non-cash working capital	**(590)**	8,933	**(1,058)**	11,153
Decommissioning expenditures	**-**	50	**-**	52
Funds from operations	**$11,248**	$12,268	**$21,923**	$24,608

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.