SOUTHERN PACIFIC
RESOURCE CORP.

ANNUAL INFORMATION FORM

FOR THE FINANCIAL YEAR ENDED
JUNE 30, 2012

SEPTEMBER 24, 2012

Statements in this Annual Information Form may be viewed as forward-looking statements. Such statements involve risks and uncertainties that could cause actual results to differ materially from those projected. There are no assurances the Corporation can fulfill such forward-looking statements and the Corporation undertakes no obligation to update such statements. Such forward-looking statements are only predictions; actual events or results may differ materially as a result of risks facing the Corporation, some of which are beyond the Corporation's control. The forward-looking statements or information contained in this Annual Information Form are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

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SCHEDULES

GLOSSARY

Certain terms and abbreviations used in this Annual Information Form are defined below:

"**2009 Credit Facility**" means the credit facility that was replaced by the 2011 Credit Facility. The 2009 Credit Facility was a reserve-based revolving credit facility with an authorized borrowing base of $55,000,000 with a Canadian chartered bank. The 2009 Credit Facility bore interest at the Canadian prime rate plus an applicable margin of between 1.75% and 3.75% per annum based on the Corporation's debt to trailing cash flow ratio. The security for the 2009 Credit Facility was comprised of a security interest on the assets of the Corporation and certain of its subsidiaries;

"**2011 Credit Facility**" means an approximately $30,000,000 first lien secured revolving credit facility with a syndicate of financial institutions which provides for a three-year revolving credit facility. Borrowings under the 2011 Credit Facility bear interest at a rate of Canadian dollar prime rate plus a margin, U.S. dollar base rate plus a margin, a LIBOR rate plus a margin, or a banker's acceptance discount rate plus a stamping fee. The 2011 Credit Facility is secured by a first ranking security interest in all of the assets of the Corporation and its subsidiaries, whether owned on the closing date or thereafter acquired, which will rank in priority to the second-priority security interest provided under the Second Lien Term Loan Facility. The Second Lien Term Loan Facility includes an accordion, subject to arranging the required incremental commitments, which will allow the 2011 Credit Facility to be increased from up to $30,000,000 to up to $80,000,000 after Phase 1 is deemed commercial;

"**2011 Debentures**" means the convertible unsecured debentures, offered pursuant to the 2011 Debenture Offering, each with an interest rate of 6% per annum. The 2011 Debentures are convertible into Common Shares at any time prior to the close of business on the earlier of: (i) the business day immediately preceding June 30, 2016; or (ii) if called for redemption, on the business day immediately preceding the date specified by the Corporation for redemption of the 2011 Debentures, based on an initial conversion ratio of 465.1163 Common Shares per $1,000 principal amount of debentures (equivalent to an initial conversion price of $2.15 per Common Share); or (iii) if subject to repurchase pursuant to a change of control, on the business day immediately preceding the payment date, subject to the satisfaction of certain conditions. The conversion rate is subject to adjustment in certain circumstances. The 2011 Debentures are listed on the TSX under the symbol "STP.DB";

"**2011 Debenture Offering**" means the underwritten short-form prospectus offering of $172,500,000 principal amount of 2011 Debentures, including the full over-allotment of $22,500,000 principal amount of 2011 Debentures, which closed on January 7, 2011;

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**AENV**" means Alberta Environment;

"**Best Estimate (P50)**" means the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate;

"**bitumen**" means a naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10,000 mPa-s (cp) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds;

"**Bounty**" means Bounty Developments Ltd.;

"**Bounty Acquisition**" means the acquisition of Bounty's entire 20 percent working interest in the McKay Block, as well as 20 percent of Bounty's working interest in 32 sections of land adjacent to and near Southern Pacific's Ells block, completed pursuant to a purchase agreement on June 1, 2010;

"**Canadian GAAP**" or "**GAAP**" means: (i) with respect to financial years beginning after January 1, 2011, the generally accepted accounting principles in Canada of publically accountable enterprises; and (ii) with respect to financial years beginning before January 1, 2011, the generally accepted accounting principles, in each case as set by the Canadian Institute of Chartered Accountants and as permitted by National Instrument 52-107 - *Financial Disclosure*, for the preparation of financial statements;

"**Common Shares**" means the common shares in the capital of the Corporation;

"**Contingent Resources**" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage;

"**Corporation**" or "**Southern Pacific**" means Southern Pacific Resource Corp., a corporation pursuant to the ABCA;

"**crude oil**" or "**oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas;

"**CSS**" means cyclical steam stimulation;

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs or support equipment and facilities and other costs of development activities, are costs incurred to:

a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

d) provide improved recovery systems;

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive;

"**ERCB**" means Alberta Energy Resources Conservation Board;

"**ERT**" means Electrical Resistivity Tomography;

"**evaluation oil sands well**" means a well drilled in an oil sands area to evaluate the oil sands and is not intended to produce hydrocarbons;

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "**prospecting costs**") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "**geological and geophysical costs**");

b) costs of carrying and retiring unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

c) dry hole contributions and bottom hole contributions;

d) costs of drilling and equipping exploratory wells; and

e) costs of drilling exploratory type stratigraphic test wells;

"**forecast prices and costs**" means future prices and costs that are:

a) generally accepted as being a reasonable outlook of the future; and

b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the reporting issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a);

"**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated;

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs;

"**GHG**" means greenhouse gas;

"**GLJ**" means GLJ Petroleum Consultants Ltd., an independent petroleum consulting firm with a head office in Calgary, Alberta;

"**gross**" means:

a) in relation to the Corporation's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

b) in relation to wells, the total number of wells in which the Corporation has an interest; and

c) in relation to properties, the total area of properties in which the Corporation has an interest;

"**heavy oil**" means, in respect of reserves or production (i) in a jurisdiction that has a royalty regime specific to heavy oil, "heavy oil" is oil that qualifies for royalties specific to heavy oil; or (ii) in a jurisdiction that has no royalty regime specific to heavy oil, "heavy oil" is oil with a density between 10° to 22.3° API;

"**High Estimate (P10)**" means an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate;

"**in-situ**" means in its original place; in position; in-situ recovery refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection and firefloods;

"**Low Estimate (P90)**" means a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate;

"**McKay Block**" means the approximately 59 sections, or 37,760 acres, of oil sands leases located approximately 45 km northwest of Fort McMurray, Alberta wherein the Corporation has a 100% working interest;

"**net**" means:

a) in relation to the Corporation's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;

b) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

"**Net Profit Royalty**" means the royalty payable on net profits which is calculated by subtracting all operating costs and fuel costs from the gross revenue;

"**NI 51-101**" means National Instrument 51-101 – *Standard of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**North STP-McKay Project Area**" means the 10.5 sections located in the northern portion of the McKay Block wherein STP-McKay is located;

"**North Peace**" means North Peace Energy Corp.;

"**North Peace Acquisition**" means the acquisition of North Peace pursuant to a plan of arrangement under the ABCA, completed November 23, 2010;

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities;

"**Phase 1**" means the SAGD facility operating at STP-McKay with a nominal capacity of 12,000 bbl/d of bitumen throughput (pending completion of the Phase 1 Expansion);

"**Phase 1 Expansion**" means the expansion of Phase 1, announced on May 10, 2012, to increase the nominal capacity of Phase 1 to 18,000 bbl/d of bitumen throughput. Southern Pacific intends to incorporate the approval for the Phase 1 Expansion into the Phase 2 approval process, which commenced on November 10, 2011;

"**Phase 2**" means the SAGD facility to be located at STP-McKay with a nominal capacity of 18,000 bbl/d of bitumen throughput. The Corporation anticipates that Phase 2 will be located on the east side of the McKay River, about 4.5 km from Phase 1 and that final Phase 2 project approval will be in place by the fourth quarter of calendar 2013;

"**possible reserves**" means those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves;

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas;

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

a) costs of lease bonuses and options to purchase or lease a property;

b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties;

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**proved property**" means a property or part of a property to which reserves have been specifically attributed;

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates being "proved reserves", "probable reserves" and "possible reserves";

"**Rochester**" means Rochester Energy Corp.;

"**Rochester Acquisition**" means the acquisition of Rochester pursuant to the plan of arrangement under the ABCA, completed March 4, 2009;

"**SAGD**" means steam assisted gravity drainage, a thermal production method for heavy oil that pairs a high-angle injection well with a nearby production well drilled along a parallel trajectory. Steam is injected into the reservoir through the upper well. As the steam rises and expands, it heats up the heavy oil, reducing its viscosity. Gravity forces the oil to drain into the lower well where it is produced;

"**Saxony**" means Saxony Petroleum Inc.;

"**Saxony Acquisition**" means the acquisition of Saxony pursuant to an amalgamation of Saxony and Southern Pacific Energy completed on April 30, 2009;

“**Second Lien Term Loan Facility**” means an approximately five-year US$275,000,000 senior secured second lien term loan. The Second Lien Term Loan Facility bears interest at the LIBOR rate (with a floor rate of 2%) plus a margin of 8.50% and is secured on a second-priority basis by substantially all the assets of the Corporation and its subsidiaries, whether owned on the closing date or thereafter acquired;

“**Senlac**” means Senlac Oil Ltd.;

“**Senlac Acquisition**” means the acquisition of all of the issued and outstanding shares of Senlac from a major oil and gas company, completed on November 3, 2009;

“**SOR**” means steam-oil ratio;

“**Southern Pacific Energy**” means Southern Pacific Energy Ltd., incorporated pursuant to the ABCA and a wholly-owned subsidiary of the Corporation;

“**Southern Pacific Oil Sands Leases**” means those leases owned by Southern Pacific as set forth herein;

“**STP-McKay**” means the SAGD thermal project located in the North STP-McKay Project Area consisting of Phase 1, Phase 1 Expansion and Phase 2;

“**STP-Senlac**” means the SAGD thermal heavy oil asset near Unity, Saskatchewan, acquired pursuant to the Senlac Acquisition, wherein the Corporation has a 100% working interest;

“**TSX**” means Toronto Stock Exchange;

“**TSXV**” means TSX Venture Exchange Inc.;

“**undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status;

“**unproved property**” means a property or part of a property to which no reserves have been specifically attributed;

“**well abandonment costs**” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite; and

“**working interest**” means the net interest held in an oil and natural gas property which normally bears its proportionate share of the costs of exploration, development and operations as well as any royalties or other production burdens.

ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Mcf/d	thousand cubic feet per day
Mstb	one thousand stock tank barrels	MMcf/d	million cubic feet per day
bbl/d	barrels per day	MMbtu	million British Thermal Units
bopd	barrels of oil per day	Bcf	billion cubic feet
NGL	natural gas liquids	GJ	gigajoule
stb	stock tank barrels		

Other

API	American Petroleum Institute
˚API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 ˚API or higher is generally referred to as light crude oil
boe	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
boe/d	barrels of oil equivalent per day
m3	cubic metres
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
McfGE	1,000 cubic feet of gas equivalent on the basis of 6 McfGEs to 1 bbl of crude oil. McfGEs may be misleading, particularly if used in isolation. A McfGE conversion ratio of 6 McfGEs to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
McfGE/D	1,000 cubic feet equivalent per day
MMcfGE	1,000 McfGE
mPa-s (cP)	MilliPascal second, a unit of viscosity that is equivalent to the centiPoise (cP)
Prob	probable reserves
Poss	possible reserves
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Metric Conversion Table

The following table sets forth certain factors for converting metric measurements into imperial equivalents.

To convert from	To imperial units	Multiply by
boe	Mcf	6
Mcf	Cubic metres (“m3”)	28.174
Cubic metres	Cubic ft	35.494
bbl	Cubic metres (“m3”)	0.159
Cubic metres (“m3”)	Bbl	6.290
Feet (“ft”)	Metres	0.305
Metres	Feet (“ft”)	3.281
Miles	Kilometres (“Km”)	1.609
Kilometres (“Km”)	Miles	0.621
Acres	Hectares (“Ha”)	0.405

INFORMATION

The information in this Annual Information Form is stated as at June 30, 2012, unless otherwise indicated. For an explanation of the capitalized terms and expression and certain defined terms, please refer to the “Glossary” and “Abbreviations and Conversion” sections at the beginning of this Annual Information Form. Except as otherwise indicated, all dollar amounts in this Annual Information Form are expressed in Canadian dollars and references to $ are to Canadian dollars. References to US$ are to United States dollars.

FORWARD LOOKING STATEMENTS

Certain statements in this Annual Information Form are “forward looking information” within the meaning of applicable securities laws. Forward looking information is frequently characterized by words such as “plan”, “expect”, “project”, “intend”, “believe”, “anticipate”, “estimate”, “scheduled”, “potential”, or other similar words, or statements that certain events or conditions “may”, “should” or “could” occur. Forward looking information is based on the Corporation’s expectations regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward looking information reflects the Corporation’s current beliefs and assumptions and is based on information currently available to it. Forward looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking information including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve and resource estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the Corporation’s ability to access sufficient capital from internal and external sources, the risks discussed under “Risk Factors” and elsewhere in this Annual Information Form and in the Corporation’s public disclosure documents, and other factors, many of which are beyond the Corporation’s control. Although the forward looking information contained in this Annual Information Form is based upon assumptions which the Corporation believes to be reasonable, the Corporation cannot make assurances that actual results will be consistent with such forward looking information. Such forward looking information is made as of the date of this Annual Information Form, and the Corporation assumes no obligation to update or revise them to reflect new events or circumstances, except as required by law. Due to the risks, uncertainties and assumptions inherent in forward looking information, prospective investors in the Corporation’s securities should not place undue reliance on this forward looking information.

Specific forward looking information contained in this Annual Information Form includes, among others, statements regarding:

- the operation of the Corporation's facilities, including STP-Senlac and STP-McKay;
- the Corporation's estimated future bitumen production and the timing associated therewith;

- estimates of the Corporation's reserves and resources and estimates of the present value of the future net revenue as evaluated by GLJ;
- capital projects including future development and exploration activities in 2012 and beyond;
- the Corporation's expansion plans for its properties, including the timing thereof and the expected increases in production and revenues attributable to such expansion plans;
- the expected timing of regulatory approvals in respect of the Corporation's expansion plans at Phase 2 and the Phase 1 Expansion;
- the sources of funding and timing of funding of future development costs;
- the Corporation's anticipated future maintenance and sustaining capital costs;
- the Corporation's expectations regarding future activity levels in the Canadian oil sands and the possible impact thereof on the price of equipment and services and availability of labour;
- the Corporation's plans for the transportation of the bitumen it produces and availability of additional rail cars, trucks, barges and pipeline options to transport dilbit;
- estimated earnings coverage ratios;
- plans to develop the STP-McKay reservoir in multiple phases;
- timing for commencement and completion of construction of Phase 2 and the Phase 1 Expansion;
- expected project life;
- estimated production levels;
- anticipated timing of bitumen production at Phase 1;
- anticipated timing of steam circulation and bitumen production;
- anticipated steam-oil ratios;
- planned design enhancements to reduce operating costs and increase plant reliability;
- anticipated increases in production of heavy crude oil at STP-Senlac;
- planned expansion of STP-Senlac;
- planned expansion of its Red Earth property;
- projections of market prices and costs;
- supply and demand for oil and natural gas; and
- expectations regarding the Corporation’s ability to raise capital;

With respect to forward looking information contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- production rates and production decline rates;
- the Corporation’s ability to recover reserves and resources;
- the Corporation's ability to optimize operating costs;
- the capacity of the Corporation's trucking, rail, shipping and pipeline arrangements to meet future transportation requirements;
- the capability of the Corporation's cogeneration plant to meet a portion of future power needs for its oil sands operations at STP-McKay;
- future bitumen, natural gas and crude oil prices, heavy oil differentials, interest rates and foreign exchange rates;
- future operating costs;
- future royalty and taxation rates;
- well abandonment costs and salvage values;
- the Corporation's ability to obtain qualified staffing and equipment in a timely and cost efficient manner to meet its demand;
- the timing for receipt of required regulatory approvals to proceed with future projects;
- capital costs associated with the construction of Phase 2 and the Phase 1 Expansion;
- the legislative and regulatory environment;
- the impact of increasing competition; and
- the Corporation's ability to obtain financing on acceptable terms.

Many of the foregoing assumptions are subject to change and are beyond the Corporation’s control.

Some of the risks that could affect the Corporation's future results and could cause results to differ materially from those expressed in the forward looking information include:

- the decline of bitumen, crude oil and natural gas prices or the increase of diluent and natural gas prices;
- changes in the differential pricing between bitumen, heavy and light crude oil prices;
- general economic conditions;
- currency fluctuations;
- difficulties encountered in delivering diluent to the Corporation's oil sands project at STP-Senlac and STP-McKay and dilbit to commercial markets;
- changes in, or the introduction of new, government regulations relating to the business of the Corporation;
- difficulties or interruptions encountered and additional costs incurred during the production of bitumen, crude oil and natural gas;
- inefficiencies, curtailments or shutdown of the STP-Senlac and STP-McKay production facilities, including the impact on SORs of its SAGD operations;
- the Corporation's ability to hire and retain skilled staff and contractors;
- difficulties and delays encountered during the construction of Phase 2 and the Phase 1 Expansion and the potential for cost overruns in connection therewith;
- uncertainties associated with estimating reserves and resources;
- geological, technical, drilling and processing problems;
- liabilities and risks, including environmental liabilities and risks, inherent in oil and natural gas operations;
- the need to obtain and maintain regulatory approvals and permits for construction and future expansions;
- changes in the royalty regime in respect of the production of crude oil, bitumen and natural gas;
- the impact of amendments to the income tax laws or government incentive programs;
- performance and availability or curtailment of facilities owned by third parties;
- costs associated with producing bitumen;
- the impact of competition;
- the need to obtain required approvals and permits from regulatory authorities;
- liabilities stemming from damage to the environment, or to third persons;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- weather conditions; and
- the other factors referred to under "*Risk Factors*".

In addition, nominal capacity is not necessarily indicative of the stabilized production levels that may be achieved at the Corporation's SAGD facilities. Moreover, reported average or instantaneous production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this Annual Information Form due to, among other factors, difficulties or interruptions encountered during the production of bitumen. Actual capital costs may differ from estimates of capital costs prepared by Management in connection with construction at Phase 1, the Phase 1 Expansion and Phase 2 and such differences may be material. Costs for and access to required labour, services and equipment, operational efficiencies or difficulties in construction and drilling, changes in scope of design and weather conditions may individually or collectively materially impact on the actual capital costs incurred in the construction at Phase 1, the Phase 1 Expansion and Phase 2.

The information contained in this Annual Information Form, including the information provided under the heading "Risk Factors", identifies additional factors that could affect the Corporation's operating results and performance. Statements relating to "reserves" and "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. The assumptions relating to the reserves and resources of the Corporation are discussed under "Statement of Reserves Data and Other Oil and Gas Information".

Forward looking information is expressly qualified in its entirety by this cautionary statement. The forward looking information is only made as of the date of this Annual Information Form.

NON-GAAP MEASURE

This Annual Information Form includes references to certain financial measures, as described below, which do not have standardized meanings prescribed by IFRS. Because this measure is commonly used in the oil and gas industry, the Corporation believes that their inclusion is useful to investors. The Corporation uses this measure to evaluate its performance. Investors are cautioned that this non-GAAP measure should not be construed as an alternative to the measure calculated in accordance with IFRS as, given its non-standardized meaning, it is unlikely to be comparable to similar measures presented by other issuers. This non-GAAP measure should not be considered an alternative to, or more meaningful than net income as determined in accordance with IFRS as an indicator of the Corporation's performance. The term "operating netback" is defined as petroleum and natural gas sales less royalties and less operating expenses.

ADDITIONAL GAAP MEASURE

This Annual Information Form includes references to a certain additional GAAP measure, as described below, which is additional to the minimal prescribed disclosure by IFRS. Because this measure is commonly used in the oil and gas industry, the Corporation believes that their inclusion is useful to investors. The Corporation uses this measure to evaluate its performance and therefore defines it as an additional GAAP measure. The term "Cash from operating activities before changes in non-cash working capital" is disclosed in the cash flow as the cash flow from operating activities before the change in non-cash working capital and decommissioning expenditures and should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of performance. The Corporation's determination of cash from operating activities before changes in non-cash working capital may not be comparable to that reported by other companies.

NAME AND INCORPORATION

The Corporation was incorporated as "New Wellington Mines Limited" pursuant to the *Companies Act* (British Columbia) on June 20, 1953. On September 30, 1970, Articles of Amendment were filed and the name was changed to "New Wellington Resources Limited". On March 25, 1976, Articles of Amendment were filed and the name was changed to "International Wellington Resources Ltd." On November 24, 1983, Articles of Amendment were filed and the name was changed to "Consolidated Wellington Resources Ltd." On August 28, 1987, Articles of Amendment were filed and the name was changed to "First Hospitality (Canada) Corporation". On November 5, 1991, Articles of Amendment were filed and the name was changed to "Southern Pacific Development Corp." The Corporation was transitioned under the *Business Corporations Act* (British Columbia) on April 20, 2005. The Articles of the Corporation were amended by Certificate of Amendment on March 2, 2006 to change the name of the Corporation to "Southern Pacific Resource Corp.", and further amended by Certificate of Amendment on March 3, 2006 to consolidate the Common Shares on a three for one basis. On November 17, 2006, Articles of Continuance were filed and the Corporation was continued under the ABCA.

On March 4, 2009, the Corporation completed the Rochester Acquisition and amalgamated with Rochester pursuant to a plan of arrangement under the ABCA. Pursuant to the Rochester Acquisition, Rochester shareholders of record received 0.1977 Common Shares for each common share of Rochester held.

On April 30, 2009, the Corporation completed the Saxony Acquisition. As part of the Saxony Acquisition, the Corporation's subsidiary, Southern Pacific Energy, amalgamated with Saxony and Saxony shareholders of record received 0.8302 Common Shares for each common share of Saxony held.

On November 3, 2009, the Corporation completed the Senlac Acquisition, thereby acquiring STP-Senlac.

On June 1, 2010, the Corporation purchased two partnerships from Bounty, which were subsequently renamed the Southern Pacific Dover Partnership and the Southern Pacific McKay River Partnership.

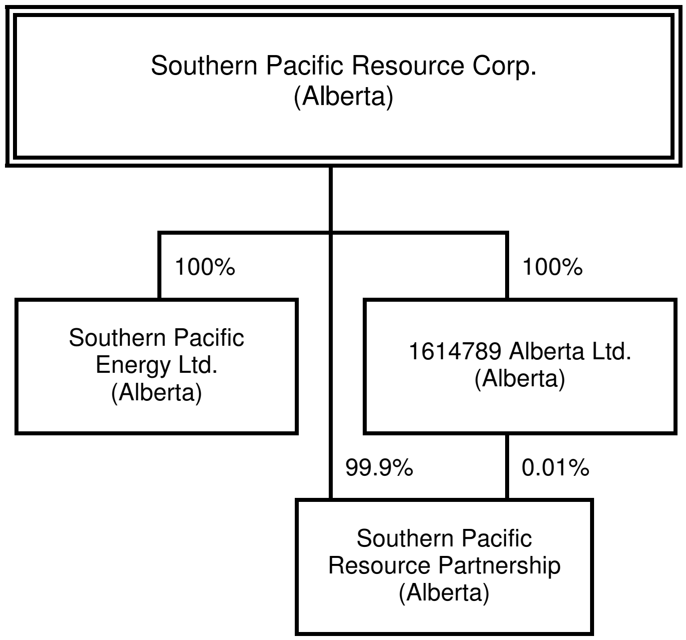
On November 23, 2010, the Corporation completed the North Peace Acquisition and acquired North Peace pursuant to a plan of arrangement under the ABCA. Pursuant to the North Peace Acquisition, North Peace shareholders of record received 0.1850 Common Shares for each common share of North Peace held.

The Corporation is a reporting issuer in each of the Provinces of Canada, other than Québec. The Common Shares and the 2011 Debentures are listed on the TSX under the symbols "STP" and "STP.DB", respectively.

The registered office of Southern Pacific, Southern Pacific Energy, 1614789 Alberta Ltd. and Southern Pacific Resource Partnership is Suite 1000, 250 – 2nd Street, S.W., Calgary, Alberta, T2P 0C1 and the head office of each such entity is located at Suite 1700 Bow Valley Square II, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

CORPORATE STRUCTURE

The Corporation's subsidiaries consist of Southern Pacific Energy and 1614789 Alberta Ltd. The Corporation also carries on business through Southern Pacific Resource Partnership, which is a partnership between the Corporation and 1614789 Alberta Ltd.



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

Southern Pacific is a Calgary-based, Canadian resource corporation engaged in the acquisition and development of heavy oil and bitumen producing properties, with a focus on thermal extraction in-situ oil sands projects in the Western Canadian sedimentary basin. Southern Pacific has two principal assets, STP-McKay and STP-Senlac. The Corporation also holds additional oil sands leases in the McMurray and Peace River sub-basins in northeastern Alberta.

The following is a general description of the development of the Corporation over the past three years.

Period from July 1, 2009 to June 30, 2010

On October 9, 2009, the Corporation entered into an agreement regarding the Senlac Acquisition. The Senlac Acquisition was an agreement with an arm's length public oil and gas corporation to acquire a subsidiary corporation, STP-Senlac, for a net purchase price of approximately $89,700,000, including transaction costs.

On October 23, 2009, the Corporation completed a bought-deal private placement of 104,000,000 subscription receipts at a price of $0.50 per subscription receipt, for gross proceeds of $52,000,000. In conjunction with the Senlac Acquisition, the Corporation also secured the 2009 Credit Facility. The 2009 credit facility was increased from $45,000,000 to $55,000,000 on March 9, 2010.

On November 3, 2009, the Senlac Acquisition was completed and the Corporation converted the subscription receipts issued on October 23, 2009 into 104,000,000 Common Shares and completed the 2009 Credit Facility.

The 2009 Credit Facility was secured by the Corporation's reserves. With the completion of the Senlac Acquisition, the Corporation obtained material changes to its reserves and heavy oil production.

On March 19, 2010, the Corporation entered into a definitive agreement with its former working interest partner, Bounty, regarding the Bounty Acquisition. The Bounty Acquisition involved the acquisition of Bounty's entire 20 percent working interest in the McKay Block. As part of the agreement, the Corporation also purchased 20 percent of Bounty's working interest in 32 sections of land adjacent to and near Southern Pacific's Ells block. The Corporation issued approximately 6,470,000 Common Shares at a price of $1.02 per share pursuant to the Bounty Acquisition.

On May 18, 2010, the Corporation completed an underwritten short-form prospectus offering of 84,000,000 Common Shares at a price of $1.20 per Common Share for gross proceeds of $100,800,000. In addition, the Corporation granted the underwriters an over-allotment option, exercisable, in whole or in part, for a period of 30 days after the offering, to purchase additional 6,300,000 Common Shares for aggregate gross proceeds of $15,120,000 at a price of $1.20 per Common Share.

On June 1, 2010, the Corporation closed the Bounty Acquisition and acquired Bounty's entire 20 percent working interest in the STP-McKay Block, as well as 20 percent of Bounty's working interest in 32 sections of land adjacent to and near the Ells block.

On June 3, 2010, the Corporation's shares began trading on the TSX and were delisted from the TSXV.

On June 17, 2010, the Corporation closed a portion of the over-allotment option regarding the May 18, 2010 underwritten short-form prospectus offering pursuant to which the underwriters purchased an additional 6,300,000 Common Shares at a price of $1.20 per Common Share and raised additional gross proceeds of $7,560,000.

Period from July 1, 2010 to June 30, 2011

On October 18, 2010, the Corporation announced that it had received Order in Council approval from the Government of Alberta regarding STP-McKay. The Order in Council authorized the ERCB to grant scheme approval No. 11461 to Southern Pacific, which allowed the Company to proceed with the development of STP-McKay. The STP-McKay project scheme approval was received on October 25, 2010.

On November 23, 2010, the Corporation completed the North Peace Acquisition. Pursuant to the North Peace Acquisition, the Corporation acquired all of the issued and outstanding securities of North Peace, a public junior oil and gas company, through a court approved plan of arrangement under the ABCA involving North Peace, its shareholders and Southern Pacific. Pursuant to the North Peace arrangement, North Peace shareholders received 0.1850 Common Shares for each common share of North Peace held, for a total of 14,093,263 Common Shares. North Peace had an in-situ oil sands project at Red Earth in the Peace River area of Alberta and its common shares were traded on the TSXV under the symbol "NPE".

On January 7, 2011, Southern Pacific completed the 2011 Debenture Offering, the Second Lien Term Loan Facility, and replaced the 2009 Credit Facility with the 2011 Credit Facility. The gross proceeds from the 2011 Debenture Offering and the Second Lien Term Loan Facility, which total approximately $447,500,000, together with both the $108,400,000 of equity raised in May 2010 and the projected earnings before interest, taxes, depreciation and amortization from STP-Senlac, allowed the Corporation to fully fund Phase 1 of STP-McKay, as well as fund its other capital programs. These include the continued development of STP-Senlac, the application for Phase 2 of the STP-McKay and exploration and development of its other leases.

On March 23, 2011, Southern Pacific commenced drilling on the first SAGD well pair at Phase 1.

On April 5, 2011, Southern Pacific announced that the Alberta Government's draft Lower Athabasca Regional Plan will have a minimal impact on the Corporation's development plans and that STP-McKay and the pilot project at Red Earth would not be affected by this plan. The proposed conservation areas will potentially affect only one of Southern Pacific's six land blocks in Alberta, namely Anzac. Southern Pacific estimates approximately 5,800 acres, or 12%, of Anzac will be rendered potentially inaccessible for in-situ development using today's existing technology. All of the lands at Anzac that have been assigned contingent bitumen resources are not included within any portion of the proposed conservation area. In August 2011, the Government of Alberta released another draft of the Lower Athabasca Regional Plan for public consultation. It is not known if or when the Lower Athabasca Regional Plan will be finalized and made into law.

On April 14, 2011, Southern Pacific announced that, based on the drilling results at Phase 1, it was proceeding with Phase 2 at STP-McKay. Phase 2 is a SAGD facility that the Corporation anticipated would have a nominal capacity of 24,000 bbl/d of bitumen throughput. The Corporation anticipates that Phase 2 will be located on the east side of the McKay River, about 4.5 km from Phase 1 and that final Phase 2 project approval will be in place by the fourth quarter of calendar 2013.

Period from July 1, 2011 to June 30, 2012

On August 2, 2011, the Corporation announced a significant increase in the volume and value of its reserves and resources in all categories. In a report prepared by GLJ, total proved reserves increased more than 89% from the previous estimate dated October 15, 2010 to 120.8 MMboe and by over 1,670% compared to the reserves report dated June 30, 2010. The increase in year over year reserves was due to the regulatory approval of Phase 1. The further increase since October 15, 2010 was attributed to revised mapping and better production performance at STP-Senlac. Also the data from the past winter's corehole drilling program at STP-McKay resulted in additional reserves being assigned. In conjunction with the Corporation's increase in proved reserves, the total proven net present value (discounted at 10% and before taxes) increased by more than 186% since October 15, 2010 to a total of $726,000,000.

On August 31, 2011 the Corporation announced the successful completion of its SAGD drilling program at Phase 1. Southern Pacific drilled a total of 12 SAGD well pairs that were expected to fill the plant nominal capacity. 24 well bores were required to complete the initial 12 SAGD well pairs. The wells were drilled from two pads; the first pad has effective horizontal well lengths averaging 800 metres and the second pad has effective horizontal well lengths averaging 1,100 metres.

In addition to the SAGD production pairs, Southern Pacific also drilled a horizontal observation well into the Wabiskaw formation with 800 metres of open-hole liner. The Corporation drilled this well above a SAGD pair on Pad 101 to evaluate pressure and temperature in the Wabiskaw formation as an indicator of steam/production performance in the underlying McMurray formation. This observation well also allowed Southern Pacific to assess the viability of recovering the significant bitumen deposit from within the Wabiskaw formation using CSS and heat conduction from the underlying SAGD process.

On November 14, 2011, Southern Pacific announced that it submitted an application on November 10, 2011 to the ERCB and AENV for approval to construct a second SAGD facility at STP-McKay, namely, Phase 2, in two 12,000 bbl/d integrated stages. The Corporation anticipated that Phase 2 would be located on the east side of the McKay River, about 4.5 km from Phase 1 and that final Phase 2 project approval will be in place by the fourth quarter of calendar 2013.

On January 4, 2012, Southern Pacific announced an increase in its proved plus probable reserves by 30% to 234 million barrels of bitumen and an increase in the proved plus probable net present value (discounted at 10%) of these reserves by $0.6 billion to $1.7 billion. The increases were a result of the filing of the Phase 2 expansion application on November 10, 2011. The filing of this application permitted GLJ to prepare proved plus probable production forecasts using the combined Phase 1 and Phase 2 nominal capacity of 36,000 bbl/d.

On May 10, 2012, Southern Pacific announced expansion plans for Phase 1. Detailed reviews of resources and facility capacities made if apparent that both the resource and the Phase 1 equipment capacities were better suited to developing the entire McKay resource based on two 18,000 bbl/d projects located on either side of the McKay River. With this re-definition, Phase 2 has been modified to a SAGD facility with a nominal capacity of 18,000 bbl/d of bitumen. The Phase 1 Expansion will increase the nominal capacity of the Phase 1 facilities to 18,000 bbl/d which is an increase of 6,000 bbl/d. The Phase 1 Expansion is anticipated to significantly reduce future capital costs in the entire project and accelerate the Corporation's production growth forecast. The cost of this expansion is approximately $25,000 per barrel of nominal capacity, or $150 million, including additional well pairs. The Phase 1 Expansion plans were in the engineering design phase for three months and based on analysis over that period, the Corporation elected to proceed with the Phase 1 Expansion prior to the construction of Phase 2. Southern Pacific does not expect this revision to significantly delay the application approval process as the changes are minimal from an environmental and regulatory perspective; virtually every modification can be viewed as an improvement to the overall scheme. Southern Pacific has already consulted with the Alberta regulators on the modification, and the appropriate steps are being taken to accommodate the Phase 1 Expansion plans within the original Phase 2 application. The Corporation is presently incorporating the Phase 1 Expansion into the project re-definition for the Phase 2 approval process, which is expected to be completed by the third quarter of calendar 2012.

On June 22, 2012 Southern Pacific submitted an application to the ERCB for approval of a scheme to recover bitumen from the Wabiskaw using cyclic steam stimulation technology. The Wabiskaw is a bitumen bearing zone situated approximately six metres above the McMurray Formation.

On June 27, 2012, Southern Pacific announced completion of a long-term arrangement to transport its bitumen to the U.S. Gulf Coast via the rail network of CN. Under this arrangement, Southern Pacific expects to significantly increase its plant gate bitumen netback using rail transportation that reduces diluent costs and offers access to Brent-based pricing as opposed to selling its bitumen into a pipeline that offers access to Western Canadian Select based pricing. Southern Pacific's bitumen volumes will be trucked approximately 60 km (38 miles) from STP-McKay to Lynton, Alta., a CN rail terminal located immediately south of Fort McMurray. From Lynton, volumes will be transferred into rail cars and shipped approximately 4,500 km (2,800 miles) over CN's network and a short-line rail partner, to a terminal in Natchez, Mississippi, located on the Mississippi River 135 km (85 miles) north of Baton Rouge, Louisiana. The bitumen will then be transferred to barges that will deliver the product as feedstock to refineries on the Gulf Coast. CN expects to commence shipment of Southern Pacific's bitumen from Fort McMurray to Natchez starting in the first quarter of calendar 2013, with volumes ramping up to more than 8,760 carloads per calendar year as production increases to peak rates.

Period Subsequent to June 30, 2012

On July 3, 2012, Southern Pacific announced that steam began circulating through the SAGD wellbores at Phase 1 on July 1, 2012. First steam is not only an important milestone in the STP-McKay project development, it is an historic event for Southern Pacific as it represents the completion of the construction, commissioning and start-up of the Corporation's first major project undertaking. Steam will now be circulated through the SAGD wellbores for a period of three to four months, after which bitumen production is scheduled to begin. Southern Pacific projects the final capital cost for Phase 1 to be $468 million, four percent over the original budget of $450 million. This includes an additional $15 million of scope changes designed to improve reliability and decrease operating costs. Increased industry activity in the second quarter affected the module fabrication costs and delivery schedules, which resulted in increased construction costs in order to meet the project schedule.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**"). One of the key features of the LARP is the establishment of Conservation Areas. As a result of LARP, the Corporation will be losing approximately 18 sections (gross) or 24%, (16 sections net or 21% net), of its oil sands leases in the Anzac area. None of these oil sands leases that the Corporation will be losing have resource or reserves assigned to them, with a majority of the leases being located along the Christina and Clearwater river valleys, which the Corporation had no plans to develop. Compensation with respect to cancellation of all or portions of Crown mineral rights agreements will be determined according to the Mineral Rights Compensation Regulation. The Corporation will be in discussion with the Crown regarding compensation for these lost oil sands leases.

On September 18, 2012, the Corporation completed the sale of the Kirby Block to an arm's length party for proceeds of $4,400,000. As at September 24, 2012, the Corporation holds five blocks: Leismer, Anzac, Hangingstone, Ells and Red Earth and has an average 85% working interest in 362 sections or 231,680 gross acres (196,736 net acres) of oil sands mineral rights excluding the aforementioned McKay Block. The Corporation did not have any reserves or resource assigned to these lands at Kirby.

Significant Acquisitions

During the fiscal year ended June 30, 2012, the Corporation did not complete any significant acquisitions.

DESCRIPTION OF THE BUSINESS OF THE CORPORATION

General

Southern Pacific is engaged in the exploration, development and production of in-situ thermal heavy oil and bitumen in the Athabasca oil sands of Alberta and in Senlac, Saskatchewan.

Southern Pacific has two principal assets in addition to its other oil sands assets. The first principal asset is its 100% working interest in approximately 59 sections, or 37,760 acres, of oil sands leases referred to herein as the "McKay Block". The McKay Block is located approximately 45 km northwest of Fort McMurray, Alberta and approximately 25 km southwest of the Suncor MacKay River SAGD project. Of the 59 sections that comprise the McKay Block, 10.5 sections located in the northern portion of the McKay Block, referred to herein as the "North STP-McKay Project Area," have been delineated with 90 evaluation wells and found to contain an estimated 168 MMbbl of proved plus probable reserves.

The North STP-McKay Project Area was selected by the Corporation for development and is the site of STP-McKay, which includes Phase 1, Phase 1 Expansion and Phase 2. Including Phase 1, Phase 1 Expansion and Phase 2, the total nominal capacity at STP-McKay is 36,000 bbl/d of bitumen throughput.

Phase 1 is a SAGD facility with a nominal capacity of 12,000 bbl/d of bitumen throughput. Southern Pacific began circulating steam through the SAGD wellbores at Phase 1 on July 1, 2012 and production is expected to commence in late 2012. Southern Pacific projects the final capital cost for Phase 1 to be $468 million, four percent over the original budget of $450 million. Increased industry activity in the second quarter of calendar 2012 affected the module fabrication costs and delivery schedules, which resulted in increased construction costs in order to meet the project schedule.

In November 2011, Southern Pacific submitted an application to the regulatory authorities to expand the nominal capacity of STP-McKay from its current capacity of 12,000 bbl/d to a nominal size of 36,000 bbl/d of bitumen throughput. The application process is currently underway and the approval is expected sometime in the fourth quarter of calendar 2013. See "*–Principal Properties – McKay Area, Alberta*".

The second principal asset of Southern Pacific is its 100% working interest SAGD thermal heavy oil asset near Unity, Saskatchewan, referred to herein as "STP-Senlac". STP-Senlac has produced an average of 4,000 barrels of heavy oil per day since it was acquired in November 2009. It has been in operation since 1996 and has produced approximately 18 MMbbl of 12° - 13° API crude oil through June 30, 2012. In the 32 months that Southern Pacific has owned STP-Senlac, it has generated approximately $160.8 million in net operating income. STP-Senlac is currently operated by a staff of 23. See "*–Principal Properties – Senlac Area, Saskatchewan*".

In addition to the two principal assets, the Corporation holds additional oil sands leases in the McMurray and Peace River oil sands in northeastern Alberta. These leases are divided into six blocks: Leismer, Kirby, Anzac, Hangingstone, Ells and Red Earth (Red Earth was acquired pursuant to the North Peace Acquisition). The Corporation has an average 85% working interest in 377 sections or 241,280 gross acres (204,416 net acres) of oil sands mineral rights outside of the McKay Block. On July 25, 2012 the Department of Energy granted Southern Pacific a three-year extension on all of its oil sands leases. With the three-year extension in place, Southern Pacific's remaining tenure ranges from 11 to 13 years. The Corporation intends to continue exploration of these blocks as part of its annual capital program, with the goal of identifying and planning future thermal project areas and to allow for continued corporate growth beyond its lands in STP-McKay and STP-Senlac.

Principal Properties

McKay Area, Alberta

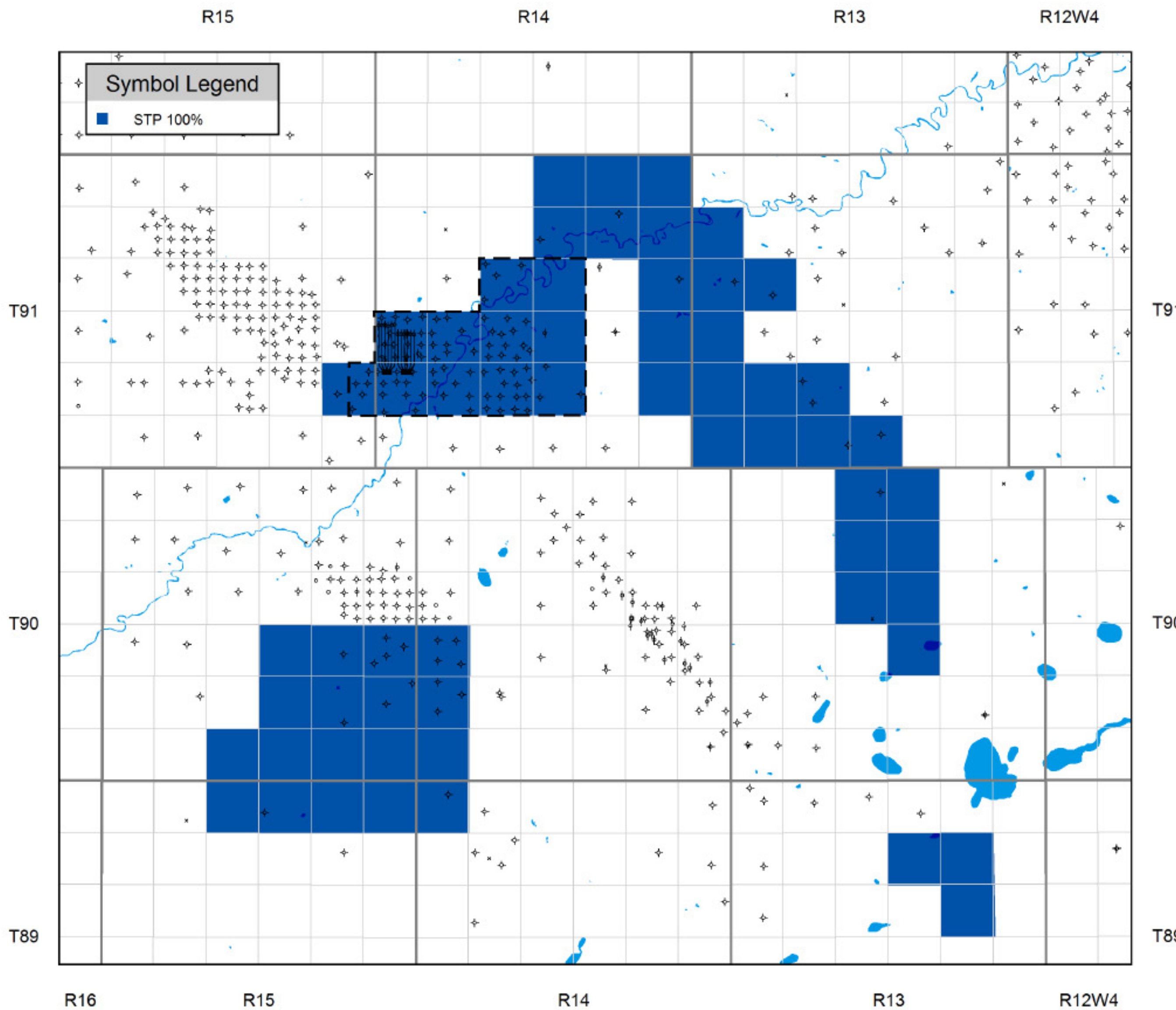
The Corporation's STP-McKay oil sands leases are located in the Athabasca oil sands in north-eastern Alberta and cover 37,760 net acres to the Corporation (100 percent working interest). The leases consist of crown leases and cover a 59 section parcel, on a gross basis. The Corporation has drilled 88 evaluation wells on the property, of which 76 were cored. Also, 43 km of two dimensional seismic, 5.1 square km of three dimensional seismic and 28 km of ERT has been shot and evaluated.

Within the STP-McKay oil sands development area, the Corporation has constructed and initiated operations at STP-McKay, a 10.5 section (27.2 square kilometres) area which has been independently assessed to contain 237 MMbbls of proved plus probable reserves in addition to 118 MMbbl of Best Estimate contingent resources as of June 30, 2012.

The Corporation has completed construction of a 29-km all weather access road, central process facility and pad site and has also drilled a total of 12 SAGD well pairs that are expected to fill the plant nominal capacity. The 24 well bores required to complete the initial 12 SAGD well pairs were drilled from two pads; the first pad has effective horizontal well lengths averaging 800 metres and the second has effective horizontal well lengths averaging 1,100 metres. In total, Southern Pacific has successfully completed 23.1 kilometres of horizontal drilling through the bitumen bearing McMurray formation.

All 12 of the SAGD well pairs encountered high quality reservoir throughout, and most notably, the absence of lean zones and shale barriers in any of the well bores. All horizontal sections were drilled to design length, with none of the well bores departing the edge of the exploitable reservoir.

In addition to the SAGD production pairs, Southern Pacific also drilled a horizontal observation well into the Wabiskaw formation with 800 metres of open-hole liner. The Corporation drilled this well above a SAGD pair on Pad 101 to evaluate pressure and temperature in the Wabiskaw formation as an indicator of steam/production performance in the underlying McMurray. This observation well will also allow Southern Pacific to assess the viability of recovering the significant bitumen deposit from within the Wabiskaw formation using CSS and heat conduction from the underlying SAGD process. An application was submitted to the ERCB in June 2012 for approval of a scheme to recover this resource using CSS technology. The application is currently under review by the ERCB. In addition to the wells, the main project facilities consist of emulsion treating and separation vessels, water treating equipment to allow produced water recycling to boiler feedwater quality, steam generators, steam and power cogeneration, tankage and truckloading facilities, associated infra-structure such as gas supply pipelines, roads and power distribution systems, all related wellpad surface equipment plus the associated gathering and distribution lines. All surface assets were commissioned and started in mid-2012. Southern Pacific began circulating steam through the SAGD wellbores at Phase 1 on July 1, 2012. First steam is not only an important milestone in the STP-McKay project development, it represents the completion of the construction, commissioning and start-up of the Corporation's first major project undertaking. Steam will now be circulated through the SAGD wellbores for a period of three to four months, after which bitumen production is scheduled to begin. Southern Pacific projects the final capital cost for Phase 1 to be $468 million, four percent over the original budget of $450 million. This includes an additional $15 million of scope changes designed to improve reliability and decrease operating costs. Increased industry activity in the second quarter affected the module fabrication costs and delivery schedules, which resulted in increased construction costs in order to meet the project schedule.



The main bitumen resource at STP-McKay is located within the McMurray Formation of the Mannville Group, at an approximate depth of 170 metres below surface. The main reservoir consists of two production facies; a channel sand and a bioturbated sand. Average exploitable reservoir thickness in the STP-McKay project area is 19.5 metres. There is minimal bottom water and no top water within the McMurray in the McKay project area. A competent caprock is provided by the Clearwater shale, which is pervasive and consistent throughout the area. There is a secondary bitumen resource in the Wabiskaw B sand located 150 metres below the surface with a minimum of 10 metres separating the base of the Wabiskaw sand from the top of the McMurray reservoir. This reservoir is a sandy marine shoreface that averages 7 metres in thickness across the project area.

The STP-McKay project area is situated 20 km west of Suncor's MacKay River SAGD project, the closest producing SAGD project. Through the evaluation of the Corporation's acreage and reservoir attributes, management of Southern Pacific believes that many of the reservoir characteristics of the STP-McKay project are similar to the producing Suncor MacKay River SAGD project.

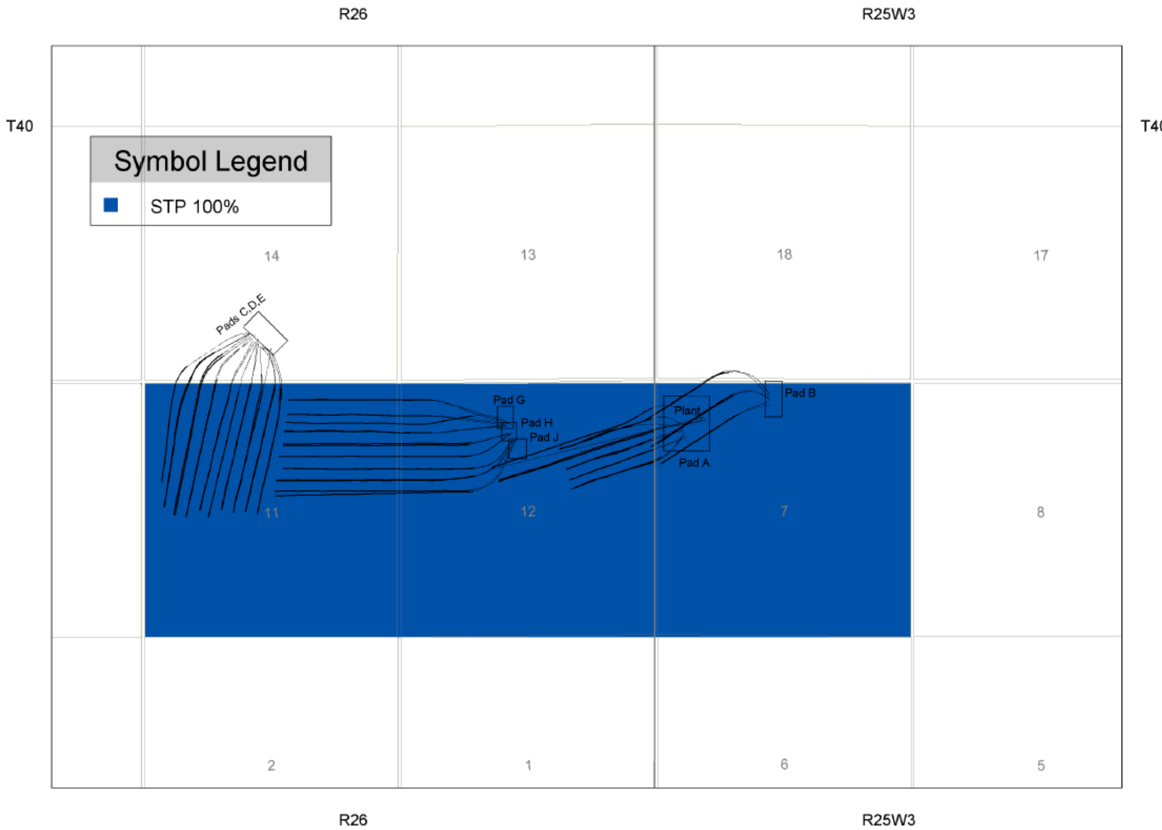
Phase 1 has a nominal capacity of 12,000 bbl/d of bitumen with an expected project life of greater than 30 years. Upon completion of the Phase 1 Expansion, Phase 1 will have a nominal capacity of 18,000 bbl/d of bitumen with an expected project life of greater than 20 years. Over the life of the STP-McKay project, there will be approximately 185 well pairs drilled from approximately 20 well pads within the Project Area, recovering in excess of 110 MMbbls of bitumen. The production life for each individual well pair is estimated to be approximately 7 – 8 years. As the individual well pair production declines, additional well pairs will be drilled throughout the North STP-McKay Project Area to maintain production.

Southern Pacific had initially submitted an application to the ERCB and AENV for approval to construct a second SAGD facility at STP-McKay, namely, Phase 2, in two 12,000 bbl/d integrated stages. However, with further analysis and facility assessment, it became apparent that both the resource and the Phase 1 equipment capacities were better suited to developing the entire McKay resource based on two approximately 18,000 bbl/d projects located on either side of the McKay River. On May 10, 2012, Southern Pacific announced the Phase 1 Expansion, a unique opportunity to increase the nominal capacity of Phase 1 to 18,000 bbl/d of bitumen throughput. The Corporation is presently incorporating the Phase 1 Expansion into the project re-definition for the Phase 2 approval process, which is expected to be completed by the third quarter of calendar 2012. With this re-definition, Phase 2 has been modified to a SAGD facility with a nominal capacity of 18,000 bbl/d of bitumen throughput. The Corporation anticipates that Phase 2 will be located on the east side of the McKay River, about 4.5 km from Phase 1 and that final Phase 2 project approval will be in place by the fourth quarter of calendar 2013.

Senlac Area, Saskatchewan

On November 3, 2009 the Corporation completed the acquisition of STP-Senlac. STP-Senlac is located at approximately township 40, range 25, west of the 3rd Meridian, approximately 37 km west of Unity, Saskatchewan and consists of three sections of 100 percent owned lands and approximately two net sections of other lands. The Corporation's assets in this area include a 100 percent working interest in 8 producing SAGD heavy oil well pairs plus two additional cyclic heavy oil/steam injection "infill wells". Heavy oil production from this property is from the Cummings-Dina formation. In this area, facilities include a SAGD thermal injection and recovery facility, tanks, pumps and production equipment associated with the producing wells.

The Corporation completed drilling and tie-in of Phase J at STP-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 from the well pair on December 29, 2011. The second and third well pairs were brought on production in January and March 2012, respectively. With these three additional well pairs on stream, STP-Senlac production averaged over 4,154 bbl/d generating near record cash from operating activities before changes in non-cash working capital of $16.5 million for the quarter ended March 31, 2012. Plans to drill and equip the next phase (Phase K) at STP-Senlac are now underway. A stratigraphic test well was drilled in September to assist in reservoir delineation for the next SAGD well pad. The well results yielded thicker than anticipated net oil pay in the producing horizon, which should result in an overall increase in the recoverable reserves expected from Phase K. Regulatory approval for the drilling of Phase K has been delayed by approximately three months due to recently introduced Saskatchewan regulations which now require an environmental review of enhanced oil recovery scheme amendments. The new regulatory process has now been incorporated into the Corporation's development planning cycle and regulatory delays on future phases of development are not anticipated. It is now anticipated that Phase K, which consists of three new SAGD well pairs, plus facilities, will be drilled, completed and equipped through the third and fourth quarter of calendar 2012, with first steam anticipated in January and oil production in February.

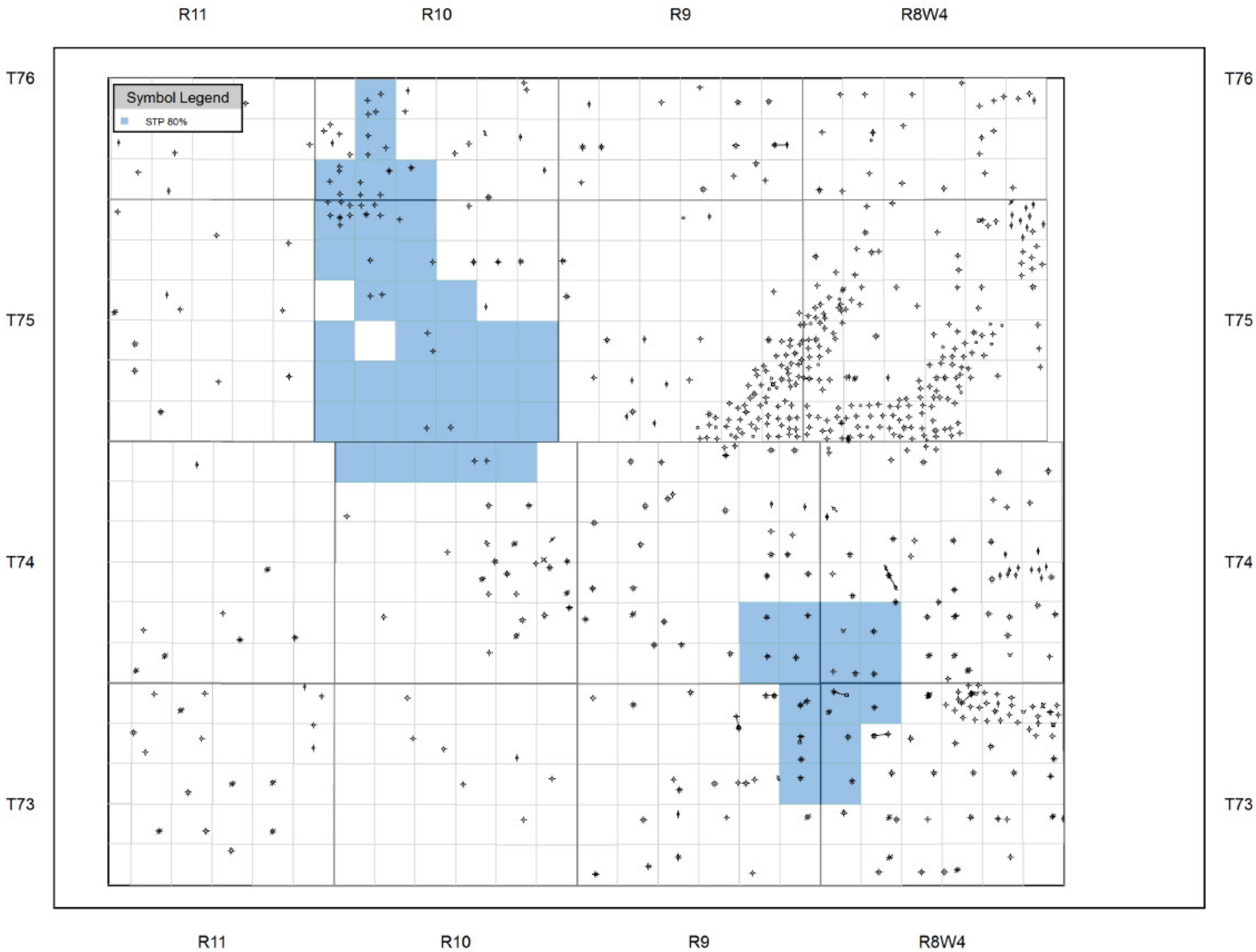


Other Oil Sands Blocks

The Corporation also holds additional oil sands leases outside of the McKay Block in the Athabasca oil sands of Alberta. The properties are split into 6 blocks; Leismer, Kirby, Anzac, Hangingstone, Ells and Red Earth. These other areas cover approximately 204,416 net acres to the Corporation (241,280 gross acres) at June 30, 2012. Of the 377 gross sections of land described above, Southern Pacific holds a 100% working interest in 185 sections, an 80% working interest in 160 sections and in the remaining 32 sections, the Corporation has a 20% working interest. There is significant tenure remaining on the lands ranging from 11 to 13 years. A total of 115 delineation wells have been drilled on these lands to date. Details of the Corporation's Contingent resources are provided herein - See "*Statement Of Reserves Data And Other Oil And Gas Information - Contingent Resources*". It is the Corporation's intent to continue exploration of these blocks as part of its annual capital program, with the intent of identifying and planning future thermal project areas, and allow for continued corporate growth beyond its lands in STP-McKay.

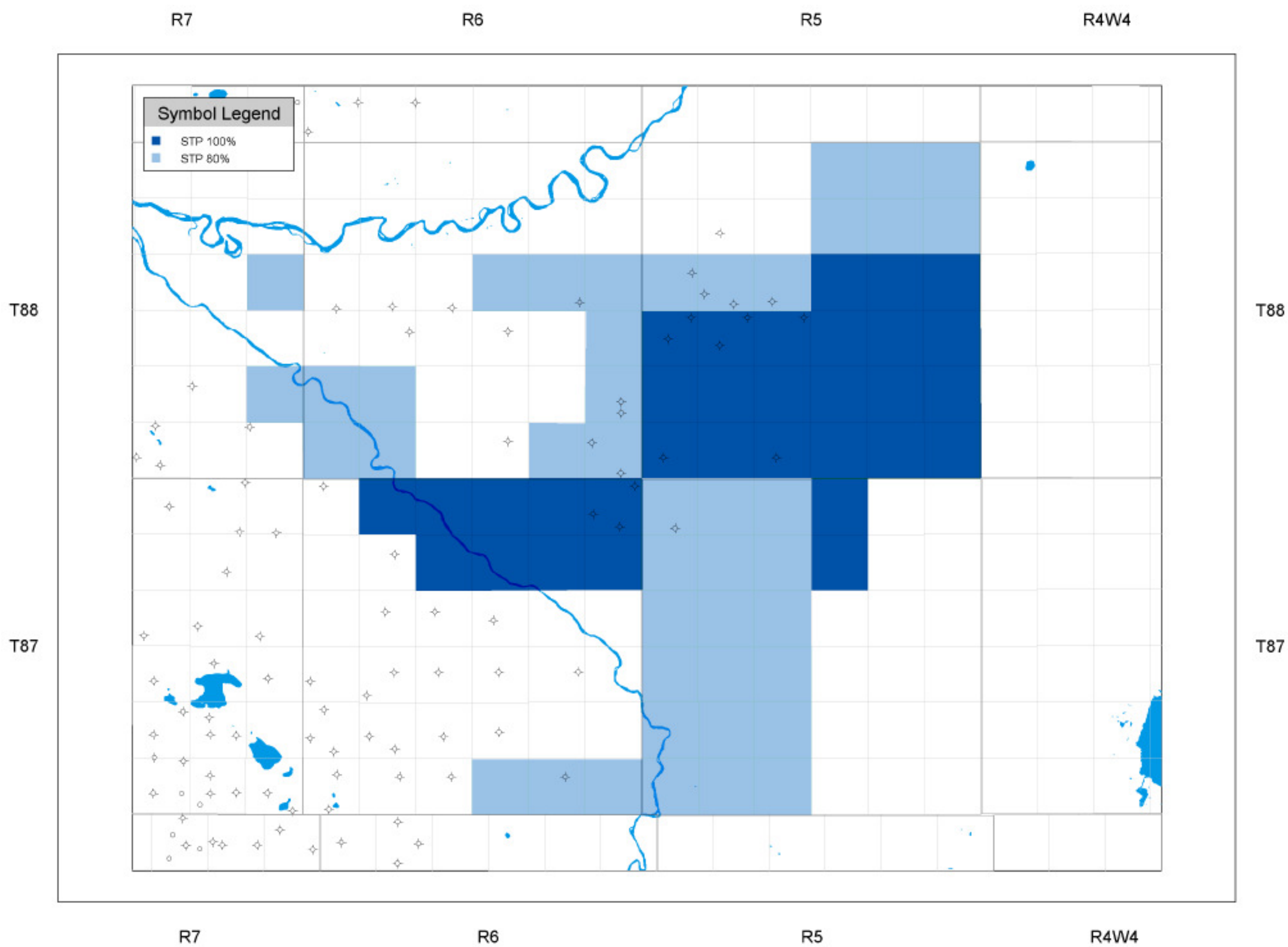
On September 18, 2012, the Corporation completed the sale of the Kirby Block to an arm's length party for proceeds of $4,400,000. As at September 24, 2012, the Corporation holds five blocks: Leismer, Anzac, Hangingstone, Ells and Red Earth and has an average 85% working interest in 362 sections or 231,680 gross acres (196,736 net acres) of oil sands mineral rights excluding the aforementioned McKay Block. The Corporation did not have any reserves or resource assigned to these lands at Kirby.

Leismer and Kirby



Note: The Kirby Block was sold on September 18, 2012.

Anzac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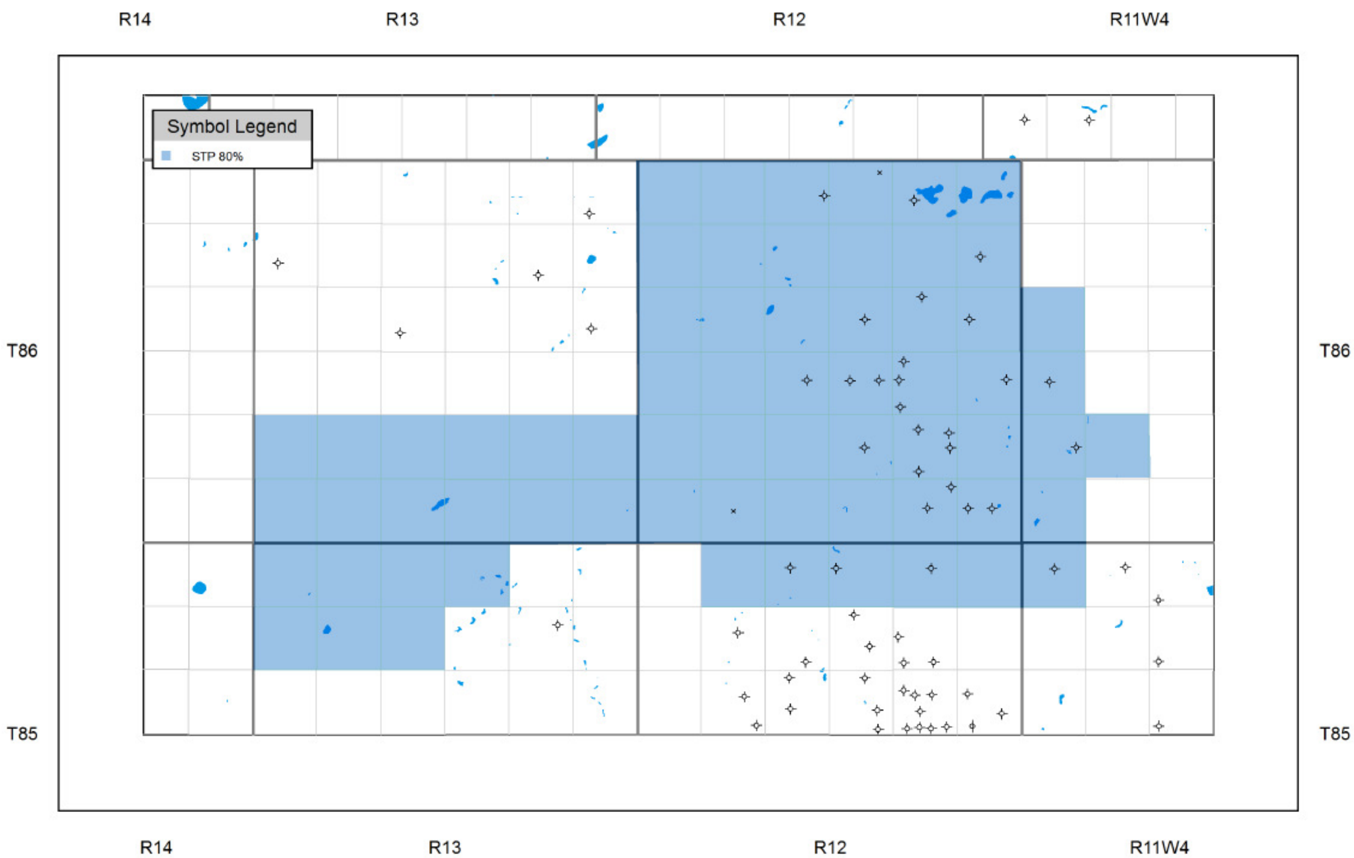
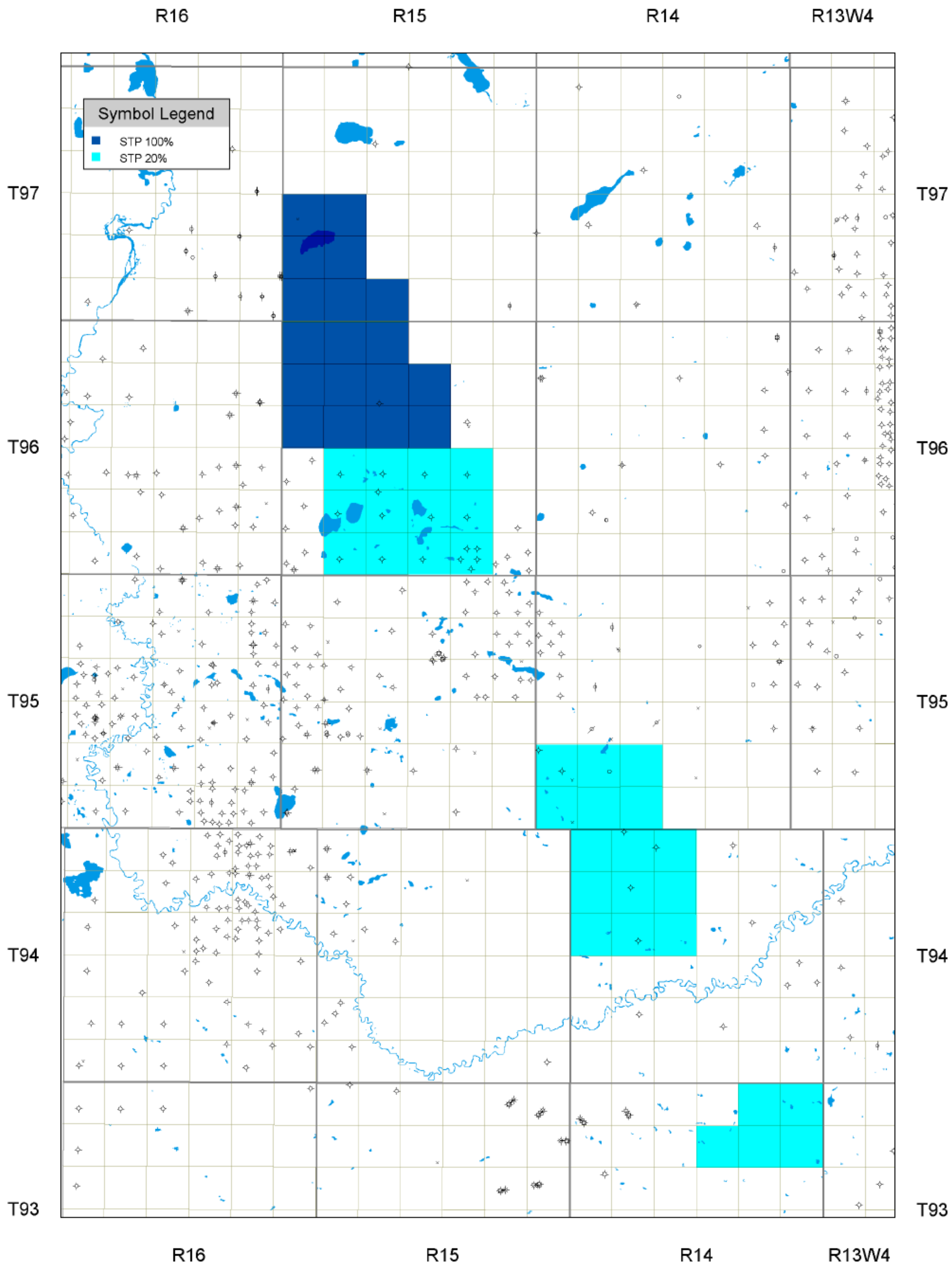
Hangingstone



Ells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R15
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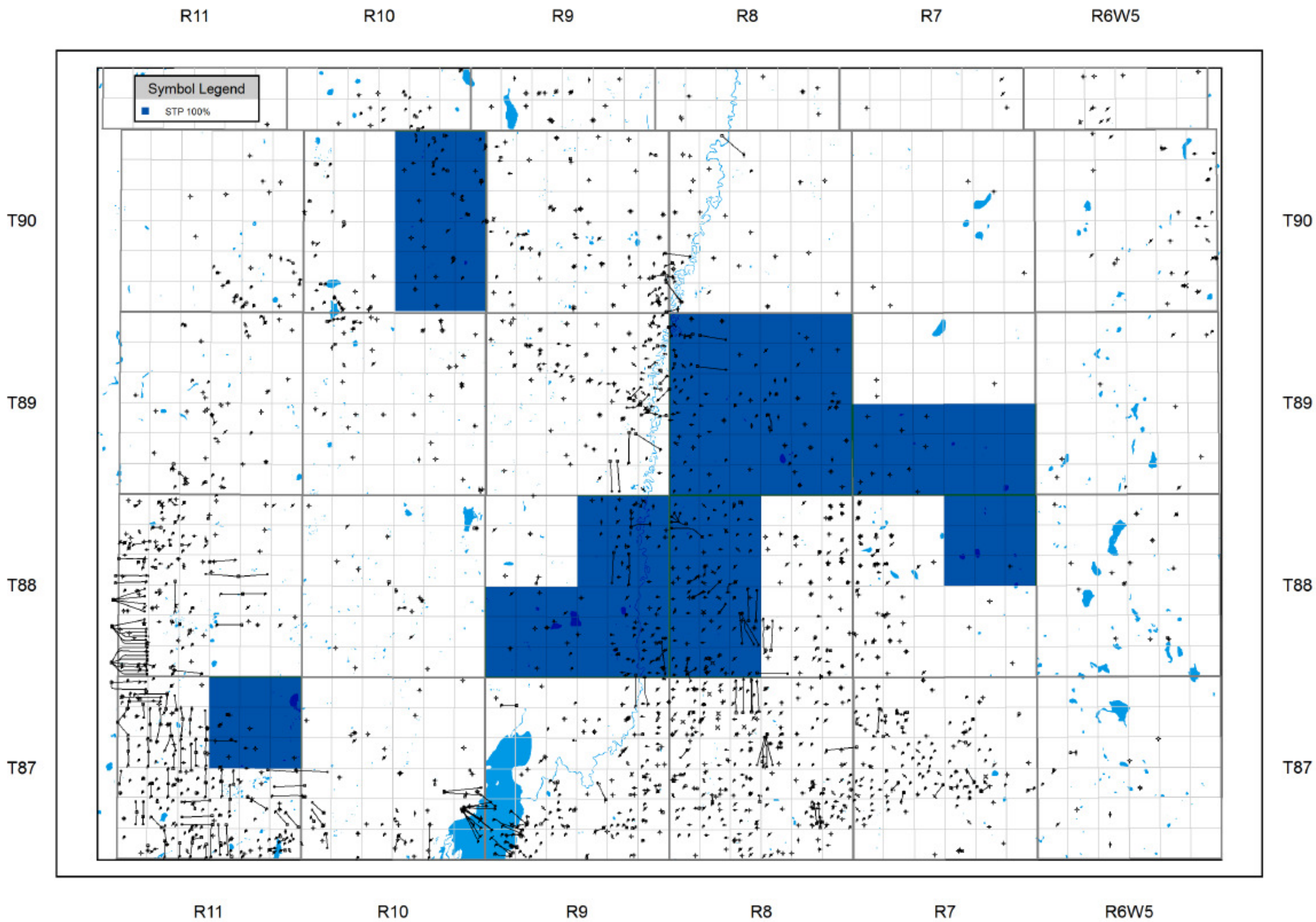
R13W4

Red Earth


R11
R10
R9
R8
R7
R6W5
Symbol Legend
STP 100%
T90
T89
T88
T87
T90
T89
T88
T87
R11
R10
R9
R8
R7
R6W5

Conventional and Heavy Oil, Properties and Wells

The Corporation also holds conventional oil and gas assets which were acquired pursuant to the Saxony Acquisition. These assets are located primarily within Alberta and total land holdings are approximately 3,520 net acres (3,840 gross acres).

The following table sets out the number of wells associated with the Corporation's heavy oil and conventional assets in which the Corporation held a working interest and which were producing, or considered to be capable of production, as at June 30, 2012.

	Oil		**Natural Gas**	
	Gross	**Net**	**Gross**	**Net**
Alberta				
Producing	-	-	-	-
Non-producing	2	2	-	-
Producing (Heavy Oil)	-	-	-	-
Non-producing (Heavy Oil)	16	16	-	-
Saskatchewan				
Producing (conventional)	-	-	1	0.5
Non-producing (conventional)	-	-	2	1.5
Producing (heavy oil)	13	11.5	-	-
Non-producing (heavy oil)	24	23.5	-	-
British Columbia				
Producing	-	-	-	-
Non-producing	-	-	-	-
Total	**55**	**53**	**3**	**2**

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

This Statement of Reserves Data and Other Oil and Gas Information is dated June 30, 2012 unless indicated otherwise. **The information is presented on a consolidated basis for Southern Pacific**.

Reserves and Future Net Revenue

The following is a summary of the reserves and the net present values of future net revenue of the Corporation as evaluated by GLJ, an independent qualified reserves evaluator appointed by the Corporation pursuant to NI 51-101. All of the Corporation's properties with reserves were independently evaluated by GLJ.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ report dated September 21, 2012 and effective June 30, 2012 (the "**GLJ Report**") will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates attributed to the Corporation's properties described herein are estimates only. The actual reserves attributed to the Corporation's properties may be greater or less than those calculated. **Readers should note that totals in the following tables may not add due to rounding.**

SUMMARY OF OIL AND GAS WORKING INTEREST RESERVES
forecast prices and costs as of June 30, 2012

	RESERVES											
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS		HEAVY OIL		BITUMEN		TOTAL OIL EQUIVALENT (CONVENTIONAL)	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
Oil Sands Business Unit												
Total Proved									112,268	91, 310	112,268	91,310
Probable Undeveloped									124,562	101,920	124,562	101,920
Total Proved Plus Probable									236,830	193,230	236,830	193,230
Possible Undeveloped									86,519	65,199	86,519	65,199
Proved Plus Probable Plus Possible									323,349	258,429	323,349	258,429
Heavy Oil Business Unit												
Total Proved							8,154	6,841			8,154	6,841
Probable							3,958	3,422			3.958	3,422
Total Proved Plus Probable							12,112	10,263			12,112	10,263
Possible							8,041	6,786			8.041	6,786
Proved Plus Probable Plus Possible							20,153	17,049			20,153	17,049
Combined Oil Sands and Heavy Oil Business Units												
Proved												
Developed Producing							2,710	2,229	15,372	14,352	18,082	16,581
Developed Non-Producing												
Undeveloped							5,444	4.612	96,896	76, 958	102,340	81,570
Total Proved							8,154	6,841	112,268	91, 310	120,422	98,151
Probable							3,958	3,422	124,562	101,920	128,520	105,342
Total Proved Plus Probable							12,112	10,263	236,830	193,230	248,942	203,493
Possible							8,041	6,786	86,519	65,199	94,560	71,985
Proved Plus Probable Plus Possible							20,153	17,049	323,349	258,429	343,502	275,478

Notes: All gross interests reflect the Corporation's working interest. *Table may not add due to rounding.

FORECAST PRICES AND COSTS
NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF JUNE 30, 2012

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	FUTURE NET VALUE[1] 10%/year ($/boe)
Oil Sands Business Unit											
Proved											
Developed Producing	404	332	277	235	201			Note (2)			
Developed Non-Producing											
Undeveloped	2,390	1,063	549	318	201						
Total Proved	2,794	1,395	826	553	402						
Probable Undeveloped	2,546	1,205	513	155	-33						
Total Proved Plus Probable	5,340	2,600	1,339	708	369						
Possible Undeveloped	3,067	973	3 85	199	130						
Proved Plus Probable Plus Possible	8,407	3,573	1,724	907	499						
Heavy Oil Business Unit											
Proved											
Developed Producing	89	83	78	74	70			Note (2)			
Developed Non-Producing											
Undeveloped	169	136	111	91	76						
Total Proved	258	219	189	165	146						
Probable	115	85	65	51	41						
Total Proved Plus Probable	373	304	254	216	187						
Possible	282	176	117	82	61						
Proved Plus Probable Plus Possible	655	480	371	298	248						
Combined Oil Sands and Heavy Oil Business Units											
Proved											
Developed Producing	493	415	355	309	271	493	415	355	309	271	
Developed Non-Producing											
Undeveloped	2,559	1,199	660	410	276	1,947	907	498	309	208	
Total Proved	3,052	1,614	1,015	718	548	2,440	1,323	853	617	479	
Probable	2,661	1,290	577	206	9	1,947	889	345	66	-79	
Total Proved Plus Probable	5,714	2904	1,593	924	557	4,387	2,211	1,198	683	400	
Possible	3,348	1,149	502	281	190	2,520	864	383	220	153	
Proved Plus Probable Plus Possible	9,062	4053	2,095	1,205	747	6,907	3,075	1,581	903	553	

Notes: (1) Before deducting future income taxes. (2) Income taxes were calculated at the corporate level only. *Table may not add due to rounding.

TOTAL FUTURE NET REVENUE

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Oil Sands Business Unit								
Proved							Note (2)	Note (2)
Developed Producing	875	59	355	53	4	404		
Developed Non-Producing	0	0	0	0	0	0		
Undeveloped	7,369	1,547	2,085	1,288	59	2,390		
Total Proved	8,244	1,606	2,440	1,341	63	2,794		
Total Proved Plus Probable	17,928	3,427	4,932	4,065	164	5,340		
Proved Plus Probable Plus Possible	26,330	5,470	7,285	4,961	207	8,407		
Heavy Oil Business Unit								
Proved							Note (2)	Note (2)
Developed Producing	166	34	36	4	3	89		
Developed Non-Producing	0	0	0	0	0	0		
Undeveloped	382	72	74	65	2	169		
Total Proved	548	106	110	69	5	258		
Probable	292	49	74	52	2	115		
Total Proved Plus Probable	840	155	184	121	7	373		
Possible	640	120	121	113	4	282		
Proved Plus Probable Plus Possible	1480	275	305	234	11	655		
Combined Oil Sands and Heavy Oil Business Units								
Proved								
Developed Producing	1,042	93	391	57	7	493	0	493
Developed Non-Producing	0	0	0	0	0	0	0	0
Undeveloped	7,750	1,619	2,158	1,352	61	2,559	612	1,947
Total Proved	8,792	1,712	2,549	1,409	68	3,052	612	2,440
Probable	9,976	1,869	2,567	2,776	103	2,661	714	1,947
Total Proved Plus Probable	18,768	3,581	5,116	4,186	171	5,713	1,326	4,387
Possible	9,042	2,164	2,474	1009	47	3,349	829	2,520
Proved Plus Probable Plus Possible	27,810	5,745	7,590	5,195	218	9,062	2,155	6,907

Notes:

(1) All reserves presented herein represent the Corporation's and the Corporation's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Corporation have been consolidated into the Corporation's accounts. *Table may not add due to rounding.

(2) Income taxes were calculated at the corporate level only.

TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
FORECAST PRICES AND COSTS
AS OF JUNE 30, 2012

RESERVES CATEGORY	FUTURE NET REVENUE BEFORE INCOME TAXES (DISCOUNTED at 10%)[3] M$	$/boe	$/McfGE
Light and Medium Oil[1]			
Heavy Oil[1]	78,120	35.04	5.84
Natural Gas[2]			
Bitumen	277,371	19.33	3.22
Total: Proved Producing	355,491	21.44	3.57
Light and Medium Oil[1]			
Heavy Oil[1]	189,176	27.65	4.61
Natural Gas[2]			
Bitumen	826,301	9. 05	1.51
Total: Total Proved	1,015,477	10.35	1.72
Light and Medium Oil[1]			
Heavy Oil[1]	253,856	24.74	4.12
Natural Gas[2]			
Bitumen	1,338,861	6.93	1.15
Total: Total Proved Plus Probable	1,592,717	7.83	1.30
Light and Medium Oil[1]			
Heavy Oil[1]	370,677	21.74	3.62
Natural Gas[2]			
Bitumen	1,724,463	6.67	1.11
Total: Total Proved Plus Probable and Possible	2,095,140	7.60	1.27

Notes:

(1) Including solution gas and other by-products and net after royalties.
(2) Including by-products but excluding solution gas.
(3) Other Corporation revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Net Reserves of the Corporation.
(4) Processing income included where applicable.
* Table may not add due to rounding.

SUMMARY OF PRICING ASSUMPTIONS
AS OF JULY 1, 2011

FORECAST PRICES AND COSTS
GLJ Petroleum Consultants
Natural Gas and Sulfur
Price Forecast
Effective July 1, 2012

Year	Henry Hub Nymex Near Month Contract Constant 2012 $ $US/mmbtu	Henry Hub Nymex Near Month Contract Then Current $US/mmbtu	Midwest Price @ Chicago Then Current $US/mmbtu	AECO/NIT Spot Then Current $Cdn/mmbtu	Alberta Plant Gate Spot Constant 2012 $ $/mmbtu	Alberta Plant Gate Spot Then Current $/mmbtu	Alberta Plant Gate ARP $/mmbtu	Alberta Plant Gate Alliance $/mmbtu	Saskatchewan Plant Gate SaskEnergy $/mmbtu	Saskatchewan Plant Gate Spot $/mmbtu	Sumas Spot $US/mmbtu	British Columbia Westcoast Station 2 $/mmbtu	British Columbia Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
2000	5.58	4.32	3.96	5.80	6.37	4.93	4.50	N/A	4.79	4.99	4.15	5.06	4.88	38.14	13.59
2001	5.08	4.03	4.45	5.65	7.65	6.07	5.41	5.31	5.72	6.15	4.57	6.32	6.29	18.29	-14.67
2002	4.13	3.36	3.25	4.27	4.77	3.88	3.88	3.65	4.04	3.96	2.68	4.18	3.93	29.38	3.04
2003	6.57	5.47	5.46	6.73	7.80	6.49	6.13	6.15	6.41	6.57	4.66	6.45	6.32	59.81	39.83
2004	7.22	6.18	6.13	6.90	7.83	6.70	6.31	6.39	6.48	6.78	5.26	6.56	6.45	62.99	38.61
2005	10.33	9.00	8.24	9.06	9.66	8.42	8.30	8.27	8.36	8.48	7.13	8.22	8.12	63.50	33.77
2006	7.84	6.99	6.93	6.71	7.81	6.96	6.57	6.36	6.67	7.06	6.27	6.58	6.45	55.07	19.27
2007	7.83	7.12	6.83	6.59	7.07	6.43	6.20	5.86	6.18	6.55	6.52	6.40	6.25	81.66	42.03
2008	9.58	8.90	8.91	8.25	8.52	7.92	7.88	7.83	8.07	8.04	8.33	8.21	8.09	497.39	488.64
2009	4.38	4.16	4.05	4.16	4.19	3.98	3.85	3.23	3.87	4.04	3.91	4.17	4.04	57.06	24.57
2010	4.60	4.40	4.53	4.03	4.11	3.93	3.77	3.31	3.96	4.00	4.31	4.01	3.91	88.94	48.26
2011	4.15	4.03	4.21	3.62	3.61	3.51	3.46	2.84	3.57	3.67	3.93	3.39	3.31	217.16	171.93
2012 Q1	2.51	2.51	2.89	2.19	2.39	2.39	2.29	1.63	2.28	2.45	2.90	2.47	2.35	198.11	155.35
2012 Q2 (e)	2.40	2.40	2.32	1.94	1.68	1.68	1.62	1.10	1.66	1.69	2.03	1.83	1.66	205.73	164.83
2012 Q3	3.00	3.00	3.10	2.76	2.56	2.56	2.51	1.87	2.61	2.70	2.70	2.56	2.39	200.00	161.08
2012 Q4	3.25	3.25	3.35	2.98	2.79	2.79	2.74	2.11	2.83	2.92	2.95	2.78	2.62	200.00	161.08
2012 Full Year	2.79	2.79	2.92	2.47	2.35	2.35	2.29	1.68	2.35	2.44	2.65	2.41	2.25	200.96	160.58
2012 Q3-Q4	3.13	3.13	3.23	2.87	2.68	2.68	2.62	1.99	2.72	2.81	2.83	2.67	2.50	200.00	161.08
2013	3.68	3.75	3.85	3.44	3.18	3.25	3.18	2.60	3.28	3.38	3.45	3.24	3.07	175.00	135.57
2014	4.08	4.25	4.35	3.90	3.56	3.70	3.63	3.09	3.73	3.84	3.95	3.70	3.53	150.00	110.06
2015	4.48	4.75	4.85	4.36	3.92	4.16	4.07	3.58	4.17	4.30	4.45	4.16	3.98	125.00	84.55
2016	4.85	5.25	5.35	4.82	4.26	4.61	4.52	4.07	4.62	4.76	4.95	4.62	4.44	125.00	84.55
2017	5.21	5.75	5.85	5.28	4.59	5.07	4.97	4.56	5.07	5.22	5.45	5.08	4.90	127.50	87.10
2018	5.50	6.19	6.29	5.68	4.86	5.47	5.36	4.99	5.46	5.62	5.89	5.48	5.30	130.05	89.70
2019	5.50	6.32	6.42	5.80	4.86	5.59	5.48	5.12	5.58	5.74	6.02	5.60	5.41	132.65	92.36
2020	5.50	6.44	6.54	5.91	4.86	5.70	5.58	5.23	5.68	5.85	6.14	5.71	5.52	135.30	95.06
2021	5.50	6.57	6.67	6.03	4.87	5.82	5.70	5.36	5.80	5.97	6.27	5.83	5.64	138.01	97.83
2022+	5.50	+2.0%/yr	+2.0%/yr	+2.0%/yr	4.87	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering charges are deducted.
AECO - C spot refers to one month price averaged for the year.

FORECAST PRICES AND COSTS
GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective July 1, 2012

Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	Nymex Wti Near Month Futures Contract Crude Oil at Cushing Oklahoma Constant 2012 $ $US/bbl	Nymex Wti Near Month Futures Contract Crude Oil at Cushing Oklahoma Then Current $US/bbl	ICE Brent Near Month Futures Contract Crude Oil FOB North Sea Then Current $US/bbl	Light Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Lloyd Blend Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	WCS Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Light Crude Oil (35 API, 1.2%S) at Cromer Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/bbl
2000	2.7	0.673	39.10	30.23	28.41	44.57	35.28	32.61	N/A	27.49	43.28	39.92	N/A	32.15	35.59	46.31
2001	2.5	0.646	32.74	26.00	24.87	39.44	27.69	23.47	N/A	16.77	35.22	31.58	N/A	31.92	31.25	42.48
2002	2.3	0.637	32.03	26.08	25.02	40.33	31.83	30.60	N/A	26.57	37.43	35.48	N/A	21.39	27.08	40.73
2003	2.8	0.716	37.30	31.07	28.47	43.66	32.11	31.18	N/A	26.26	40.09	37.55	N/A	32.14	34.36	44.23
2004	1.8	0.770	48.38	41.38	38.02	52.96	37.43	36.31	N/A	29.11	49.14	45.64	N/A	34.70	39.97	53.94
2005	2.2	0.826	64.93	56.58	55.14	69.02	44.73	43.03	43.74	34.07	62.18	56.77	N/A	43.04	51.80	69.57
2006	2.0	0.882	74.31	66.22	66.16	73.21	51.82	50.36	50.66	41.84	66.38	62.26	N/A	43.85	60.17	75.41
2007	2.2	0.935	79.69	72.39	72.71	77.06	53.64	52.03	52.38	43.42	71.13	65.71	N/A	49.56	61.78	77.38
2008	2.4	0.943	107.27	99.64	98.30	102.89	84.31	82.60	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.880	64.98	61.78	62.50	66.32	60.18	58.40	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.971	83.30	79.52	80.25	77.87	68.45	66.95	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.012	97.91	95.12	110.86	95.53	78.58	76.84	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012 Q1	2.3	0.999	102.93	102.93	118.35	92.72	83.07	81.48	81.66	71.86	90.68	87.93	N/A	40.20	70.54	110.18
2012 Q2 (e)	1.5	0.990	93.36	93.36	108.65	83.00	71.43	69.69	69.92	59.46	79.86	76.17	N/A	25.78	67.02	99.56
2012 Q3	2.0	0.980	85.00	85.00	95.00	79.08	67.22	65.64	65.94	57.05	77.50	74.34	8.92	23.72	61.68	90.94
2012 Q4	2.0	0.980	85.00	85.00	95.00	79.08	67.22	65.64	65.94	57.76	77.50	74.34	9.71	35.59	61.68	88.57
2012 Full Year	2.0	0.987	91.57	91.57	104.25	83.47	72.24	70.61	70.86	61.53	81.38	78.19	N/A	31.32	65.23	97.31
2012 Q3-Q4	2.0	0.980	85.00	85.00	95.00	79.08	67.22	65.64	65.94	57.40	77.50	74.34	9.32	29.66	61.68	89.76
2013	2.0	0.980	88.24	90.00	97.50	86.73	72.42	70.69	70.99	62.27	83.27	79.80	11.30	52.04	67.65	95.41
2014	2.0	0.980	91.31	95.00	100.00	95.92	80.09	78.17	78.47	70.70	90.16	87.29	12.88	57.55	74.82	99.76
2015	2.0	0.980	94.23	100.00	100.00	101.02	84.35	82.33	82.63	74.51	94.96	91.93	14.47	60.61	78.80	105.06
2016	2.0	0.980	92.38	100.00	100.00	101.02	84.35	82.33	82.63	74.51	94.96	91.93	16.05	60.61	78.80	105.06
2017	2.0	0.980	90.57	100.00	100.00	101.02	84.35	82.33	82.63	74.51	94.96	91.93	17.64	60.61	78.80	105.06
2018	2.0	0.980	90.00	101.35	101.35	102.40	85.50	83.45	83.75	75.54	96.25	93.18	19.03	61.44	79.87	106.49
2019	2.0	0.980	90.00	103.38	103.38	104.47	87.23	85.14	85.44	77.09	98.20	95.07	19.45	62.68	81.49	108.65
2020	2.0	0.980	90.00	105.45	105.45	106.58	89.00	86.86	87.16	78.67	100.19	96.99	19.83	63.95	83.13	110.84
2021	2.0	0.980	90.00	107.56	107.56	108.73	90.79	88.62	88.92	80.28	102.21	98.95	20.24	65.24	84.81	113.08
2022+	2.0	0.980	90.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

Properties with no Attributed Reserves

As at June 30, 2012, the Corporation had 272,320 gross (235,456 net) acres of oil sands properties in Alberta in which the Corporation has an interest, but no reserves have been assigned. Contingent resources have been assigned to the properties, but further development drilling is required to convert the resources to reserves. The Corporation has no oil sands properties in which its rights to explore, develop and exploit will, absent further action, will expire within one year.

There are 320 net acres that will expire within one year without any action by the Corporation and which do not have any reserves assigned to them.

Contingent Resources Estimates

GLJ also completed evaluations of the Corporation's year-end unconventional bitumen contingent resources located on the Corporation's oil sands leases in the Athabasca Oil Sands Region of northern Alberta.

The Following table summarized the Corporation's working interest contingent resources effective June 30, 2012 for the leases in the Athabasca Oil Sands Region.

	Working Interest Recoverable (MMBoe)	Net Present Value (Before Tax - WI) (Cdn $ million)		
		8%	10%	12%
Contingent Resources				
Low Estimate (P90) Contingent Resource	201	847	514	267
Best Estimate (P50) Contingent Resource	525	1,696	959	485
High Estimate (P10) Contingent Resource	1,054	4,236	2,607	1,518

Note: Reserves and contingent resources involve different risks associated with achieving commerciality. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Future net revenues associated with reserves and resources do not necessarily represent fair market value.

The recovery and production estimates of the Corporation's contingent resources provided herein are only estimates and there is no guarantee that the estimated contingent resources will be recovered or produced. Actual contingent resources may be greater than or less than the estimates provided herein. The contingencies which currently prevent the classification of the contingent resources disclosed in the tables below as reserves consist of: the need for further facility design, preparation of firm development plans and regulatory applications (including associated reservoir studies and delineation drilling) and corporate approvals to proceed with development. The development plans, reservoir studies and delineation drilling are often completed in the course of preparing the Corporation's application for regulatory approvals. Once all regulatory and corporate approvals are received and any other contingencies are removed, the resources may then be reclassified as reserves. There is no certainty that it will be commercially viable for the Corporation to produce any portion of the contingent resources on any of its properties.

Forward Contracts

The Corporation enters into certain financial derivative contracts in order to reduce its exposure to market risks from fluctuations in commodity prices, foreign currency and interest rates. These instruments are not used for speculative purposes. The Corporation 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 "held for trading" and recorded on the balance sheet at fair value at each reporting date. Realized and unrealized gains and losses on these contracts are recognized in net income. Attributable transaction costs are recorded in the Corporation's statement of operations.

The following table sets out the commodity contracts that Southern Pacific has entered into, as of September 24, 2012, to reduce the risk of realized oil prices and gas purchases.

Contract Term	Type	Volume	Price
July 1, 2012 to Dec 31, 2012	Oil collar (WTI)	750 bbl/d	US$80.00-$101.10
July 1, 2012 to Dec 31, 2012	Oil collar (WTI)	750 bbl/d	US$80.00-$101.12
July 1, 2012 to Dec 31, 2012	Oil collar (WTI)	700 bbl/d	US$90.00-$100.00
Jan 1, 2013 to Dec 31, 2013	Oil collar (WTI)	1,000 bbl/d	US$90.00-$105.00
Jan 1, 2013 to Dec 31, 2013	Oil collar (WTI)	1,000 bbl/d	US$95.00-$105.25
Jan 1, 2012 to Dec 31, 2012	FX contract (US$)	750 bbl/d	US$85 WTI, at 1.00 CAD/USD
Jan 1, 2012 to Dec 31, 2012	FX contract (US$)	750 bbl/d	US$70 WTI, at 1.0290 CAD/USD
Jan 1, 2012 to Dec 31, 2012	Differential Swap (WTI)	1,000 bbl/d	WTI-US $17.25
Jan 1, 2012 to Dec 31, 2012	Differential Swap (WTI)	500 bbl/d	WTI-US $16.95

Fixed Price Contracts

The Corporation has also committed to the following fixed price gas purchase contracts to reduce the risk of gas price uncertainty, which is a significant input cost.

Contract Term	Type	Volume	Price
Jan 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	1,000 gj/day	$4.14
Jan 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	1,000 gj/day	$4.00
Jan 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	1,000 gj/day	$3.93
Jan 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	500 gj/day	$3.86
July 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	2,000 gj/day	$2.96
July 1, 2012 to Dec 31, 2012	Natural gas fixed purchase (AECO)	1,000 gj/day	$2.75

Contract Term	Type	Volume	Price
Jan 1, 2013 to Dec 31, 2013	Natural gas fixed purchase (AECO)	1,500 gj/day	$3.025
Jan 1, 2013 to Dec 31, 2013	Natural gas fixed purchase (AECO)	1,000 gj/day	$3.01
Jan 1, 2013 to Dec 31, 2013	Natural gas fixed purchase (AECO)	1,000 gj/day	$2.88
Jan 1, 2013 to Dec 31, 2013	Natural gas fixed purchase (AECO)	1,000 gj/day	$2.95

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation has abandoned all of its evaluation oil sands wells (coreholes) drilled to date. There will be some additional work over the next few winters to fully reclaim the sites but it is not considered significant. In the future, as the Corporation develops its projects, producing well abandonment costs and plant site abandonment costs will be factored into the reserve evaluations reports to reflect overall net revenue and project value.

The Corporation is required to provide for future removal and restoration costs on its conventional oil and gas assets. Southern Pacific estimated these costs in accordance with the existing laws, contracts or other policies. The fair value of the liability for the asset retirement obligations is recorded in the period in which it is to be incurred, discounted to its present value using the Corporation's credit adjusted 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 the passage of time and 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. At June 30, 2012, the Corporation had 138 net wells to abandon.

Tax Horizon

The Corporation was not required to pay income taxes during the year ended June 30, 2012. The Corporation estimates that it will not be required to pay income taxes until after 2018.

Costs Incurred

The following table shows (in thousands of dollars) the Corporation's costs for the categories for the year ended June 30, 2012:

	June 30, 2012
	($)
Development	334,784
Exploration	5,885
Disposition of petroleum and natural gas assets	(2,106)
Property Acquisition (Proved Properties)	-
Property Acquisition (Unproved Properties)	-
Total	**338,563**

Exploration and Development Activities

During the financial year ending June 30, 2012, the Corporation drilled 31 gross (31 net) development wells.

Of the 31 gross (31 net) development wells, 15 wells were completed as SAGD producing oil wells, 15 wells were completed as SAGD steam injection wells and 1 well was completed as an observation well.

Generally, the Corporation's most important current and likely exploration and development activities are to continue to maintain production levels between 4,000 and 5,000 bopd with continued SAGD development drilling at STP-Senlac. The Corporation also remains focused on continued exploration activities at both STP-McKay as well as its six other Alberta based oil sands properties.

Reserves Reconciliation

A reconciliation of changes to the Corporation's proved and proved plus probable reserves is provided in the table below. This reconciliation reflects changes to the Corporation's reserves estimated using forecast prices and costs.

Reconciliation of Corporation Reserves by Principal Product Type

Forecast Prices and Costs

FACTORS	LIGHT AND MEDIUM OIL			NATURAL GAS			NATURAL GAS LIQUIDS		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
June 30, 2011	0	0	0	0	0	0	0	0	0
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	1	-	1	19	-	19	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	-1	-	-1	-19	-	-19	-	-	-
June 30, 2012	0	0	0	0	0	0	0	0	0

Reconciliation of Corporation Reserves by Principal Product Type

Forecast Prices and Costs

FACTORS	HEAVY OIL			BITUMEN		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
June 30, 2011	8,588	4,376	12,964	112,195	55,841	168,036
Extensions	-	-	-	-	53,658	53,658
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	897	-418	479	73	-73	-
Discoveries	-	-	-	-	15,136	15,136
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-1,331	-	-1,331	-	-	-
June 30, 2012	8,154	3,958	12,112	112,268	124,562	236,830

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table shows for each product type the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financials years and in aggregate before that time.

	Light & Medium Oil		Heavy Oil		Associated &Non-Associated Gas		Natural Gas Liquids		Bitumen	
Proved	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked
Undeveloped	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl
Prior to 2010	0	0	0	0	1,012	1,012	15	15	0	0
2010	0	0	4,777	4,777	0	0	0	0	0	0
2011	0	0	1,240	6,017	0	0	0	0	112,195	112,195
2012	0	0	0	5,444	0	0	0	0	0	96,895
	Light & Medium Oil		**Heavy Oil**		**Associated &Non-Associated Gas**		**Natural Gas Liquids**		**Bitumen**	
Probable	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked
Undeveloped	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mbbl	Mbbl
Prior to 2010	23	23	0	0	795	795	13	13	54,077	54,077
2010	0	0	2,371	2,371	0	0	0	0	113,997	168,074
2011	0	0	1,673	4,045	0	0	0	0	0	55,841
2011	0	0	0	2,648	0	0	0	0	68,794	120,883

Note:
(1) Natural gas and NGL reserves as defined by NI 51-101 standards.

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into the Corporation's development plans. The Corporation plans to seek strategic partners to assist in the development of its proved undeveloped reserves. Timing of the development of such reserves will be dependent upon selection of an appropriate partner.

Significant Factors and Uncertainties

The Corporation does not anticipate any significant economic factors or significant uncertainties that will affect any particular components of the reserves data. However, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control (see "*Risk Factors*").

Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Corporation's reserves.

	2012 (MM$)	2013 (MM$)	2014 (MM$)	2015 (MM$)	2016 (MM$)	Remainder of Future Development (MM$)
Proved						
Developed Producing	21	5	5	5	4	17
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	22	69	8	38	34	1,182
Total Proved	43	74	13	43	38	1,199
Probable	10	16	282	362	495	1,611
Total Proved Plus Probable	53	90	295	405	533	2,810
Possible	1	-7	-8	0	-42	1,065
Proved Plus Probable Plus Possible	54	83	287	405	491	3,875

Notes:
(1) Table may not add due to rounding.
(2) All of the Corporation's reserves are located in Canada.
(3) Sources of funding for development for future development costs are anticipated to be internally-generated cash flow and debt or equity financing, where necessary.

The Corporation does not anticipate that the costs of funding undeveloped reserves to be uneconomic under the current market conditions.

Production Estimates

The following table discloses for each product type the total proved plus probable forecasted volume of production estimated by GLJ for 2012 in the estimates of future net revenue disclosed above under the heading "*Statement of Reserves Data and Other Oil and Gas Information*".

	2012 Remaining Calendar Year - Forecast Prices & Costs Total Proved Gross Daily Production (2)	2012 Remaining Calendar Year - Forecast Prices & Costs Proved plus Probable Gross Daily Production (2)
Reserves Category		
Light & Medium Oil (bbl/d)	-	-
Heavy Oil (bbl/d)	4,724	4,997
Associated and Non-Associated Gas (Mcf/d)	-	-
Natural Gas Liquids (bbl/d)	-	-
Total(1) (boe/d)	4,724	4,997

Notes:

(1) Barrels of Oil Equivalent (boe) have been reported based on natural gas conversion of 6 Mcf/1 bbl.

(2) Gross production is the Corporation's interest before all royalty deductions.

Production History

The following table discloses, on a quarterly basis for the year ended June 30, 2012, the Corporation's share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

	Three Months Ended				
	September 30, 2011	December 31, 2011	March 31, 2012	June 30, 2012	Average
Average Daily Production					
Heavy Oil (bbl/d)	3,778	3,224	4,154	3,402	3,639
Natural Gas (Mcf/d)	38	146	13	11	52
Total (boe/d)	**3,784**	**3,249**	**4,156**	**3,404**	**3,648**
Average Price Received ($)					
Heavy Oil (bbl/d)	59.72	73.84	64.49	56.51	63.51
Natural Gas (Mcf/d)	3.81	3.09	2.96	2.17	3.16
Total (boe/d)	**59.65**	**73.54**	**64.52**	**56.49**	**63.41**
Combined Netback ($)					
Revenue	59.65	73.54	64.52	56.49	63.41
Royalties	(10.38)	(10.86)	(11.48)	(10.48)	(10.82)
Operating Costs	(12.02)	(11.26)	(8.63)	(11.05)	(10.66)
Netback	**37.25**	**51.42**	**44.41**	**34.96**	**41.93**

Production Volume by Field

The following table discloses for each important field, and in total, the Corporation's production volumes for the financial year ended June 30, 2012 for each product type.

Field	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	boe (boe/d)	%
Senlac	3,639	46	3,646	99.9
Other	-	6	2	0.1
Total	3,639	52	**3,648**	**100.0**

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of undeveloped properties in which Southern Pacific has an interest and also the number of net acres for which Southern Pacific has rights to explore, develop or exploit will, absent further action, expire within one year.

Area	Gross Acres	Net Acres	Net acres Expiring Within One Year
Alberta	276,160	238,976	320
Saskatchewan	320	160	-
Total	**276,480**	**239,136**	**320**

Southern Pacific's focus is on the development of its oil sands leases in the Athabasca oil sands region. As such, there is no subsequent work plan for the mineral rights that will expire in the following year as the expiring rights are low interest lands in our conventional oil and gas portfolio.

Employees/Consultants

The Corporation's staffing levels, as at September 24, 2012, was approximately 114 full-time employees and 22 part-time consultants located in Calgary, Alberta and at STP-Senlac, STP-McKay and the Corporation's Red Earth property. The level of staffing will vary based on future operational and administrative demands.

Environmental

The Corporation believes that it is in compliance with applicable existing environmental laws and regulations and is not aware of any proposed environmental legislation or regulations with which it would not be in material compliance. However, the natural resources industry may in the future become subject to more stringent environmental protection rules. This could increase the cost of doing business and may have a negative impact on earnings in the future.

Reorganizations

The Corporation has not completed any material reorganizations within the three most recently completed financial years.

RISK FACTORS

Risks Relating to Economic Conditions, Commodity Pricing and Exchange Rate Fluctuations

The Corporation's results of operations depend upon the prevailing prices of crude oil and natural gas in the worldwide markets. Those prices are subject to widespread fluctuations.

The Corporation's revenues, cash flow, earnings, cost of capital, asset values, results of operations and financial condition are dependent upon the prevailing price of crude oil and natural gas and heavy oil (which includes bitumen blends) differentials. These commodity prices are beyond the control of the Corporation. The

Corporation's financial condition, operating results and future rate of growth depend upon the prices that the Corporation receives for its oil and natural gas. Such prices also affect the amount of the Corporation's cash flow available for capital expenditures and the Corporation's ability to access funds.

A significant decline in crude oil and natural gas prices would adversely impact the market value and lending value of the Corporation's estimated proved reserves. Sustained low prices could result in a material reduction of the Corporation's operating and financial results, revenues, reserves and overall value. In addition, any prolonged period of low crude oil prices could result in a decision by the Corporation to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery projects or to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in the Corporation's revenues and earnings and could materially impact the Corporation's ability to meet its debt servicing obligations and could expose the Corporation to significant additional expense as a result of any future long-term contracts. If production was not suspended or reduced during such period, the sale of the petroleum products produced by the Corporation at such reduced prices would lower its revenues and could result in losses.

The market prices for heavy oil are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in the heavy oil differentials could have an adverse effect on the Corporation's results of operations and financial condition.

The Corporation conducts an assessment of the carrying value of its assets to the extent required by IFRS. If crude oil and/or natural gas prices or the market value of investment holdings decline, the carrying value of the Corporation's assets could be subject to downward revision and its earnings could be adversely affected. Although the Corporation does not currently anticipate any “ceiling test” write downs of its oil and gas assets, or impairment charges to its other assets, there can be no assurance that declines in crude oil prices or other circumstances will not result in such “ceiling test” write downs or impairment charges at some future date.

Crude oil and natural gas prices can fluctuate significantly.

Crude oil prices have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand factors beyond the Corporation's control. Among the factors that can cause crude oil and natural gas price fluctuations are:

- changes in the level of consumer demand for petroleum products and natural gas;
- the domestic and foreign supply of crude oil and natural gas, including the decisions of the Organization of Petroleum Exporting Countries relating to export quotas and their compliance or non-compliance with such self-imposed quotas;
- weather conditions, including hurricanes, floods and other natural disasters;
- domestic and foreign governmental regulations;
- the effect of worldwide conservation of resources;
- new bitumen, crude oil and natural gas discoveries;
- economic growth in developed and emerging nations;
- the price and availability of alternative fuels, including liquefied natural gas;
- political conditions in crude oil and natural gas producing regions, including terrorist activities and other hostilities;
- the proximity of reserves to, and capacity of, transportation facilities;
- constraints in transportation facilities including those resulting from pipeline breaks or curtailments;
- the availability of refining capacity;
- the price of foreign imports of crude oil, natural gas and refined products;
- overall global and domestic economic conditions; and
- concern over climate change or emissions of GHGs.

The price of commodity inputs is volatile.

The nature of the Corporation's operations results in exposure to fluctuations in bitumen, diluent and gas prices. Natural gas is a significant component of the Corporation's cost structure, as it is used to generate steam for the SAGD process. Diluent, such as condensate, is also expected to be one of the Corporation's significant commodity inputs and to decrease the viscosity of the bitumen in order to allow it to be transported.

Historically, crude oil prices have been positively correlated with the prices of natural gas and condensate. As a result, the Corporation expects to be able to offset a portion or all of the increase in its costs associated with an increase in the price of natural gas or condensate with an increase in revenue that results from higher oil prices. The Corporation believes that this correlation has been caused by factors that are not within its control, and investors are cautioned not to rely on this correlation continuing. If the prices of these commodities cease to be positively correlated, and the price of crude oil while the prices of natural gas or diluent rise or remain steady, the Corporation's results of operations, financial condition and prospects could be adversely affected.

Global financial conditions have been subject to increased volatility. This may impact the Corporation's ability to obtain equity, debt or bank financing in the future and may adversely impact its operations.

Global financial conditions are subject to increased volatility which may impact the Corporation's ability to obtain equity, debt or bank financing on terms commercially reasonable to the Corporation, if at all. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. A return to the levels of volatility and market turmoil seen during the 2008/2009 global recession could adversely impact the Corporation's operations and the trading price of its securities.

In addition, certain of the Corporation's customers could experience an inability to pay the Corporation, in the event they are unable to access the capital markets to fund their business operations.

The Corporation is subject to foreign currency exchange fluctuation exposure.

Revenue received from the sale of crude oil is generally referenced to a price denominated in U.S. dollars. The Corporation reports its operating results, as contained in its balance sheet, statement of comprehensive income (loss) and statement of cash flows, in Canadian dollars, fluctuations in product pricing and fluctuations in the rate of exchange between the U.S. dollar and Canadian dollar would affect, and could result in a material change in, reported results.

The Corporation engages in hedging activities which may have a negative impact on earnings and cash flow.

From time to time the Corporation avails itself of exchange-traded or over-the-counter derivative structures to hedge commodity, interest rate and foreign exchange risk. Risks associated with such products include, but are not limited to, counterparty risk, settlement risk, basis risk, liquidity risk and market risk which could impair or negate the Corporation's hedging strategy and result in a negative impact on its earnings and cash flow.

Due to the uncertain worldwide economic environment, there can be no assurance that the Corporation will be able to engage credit worthy counterparties in hedging activities with it.

Risks Relating to STP-Senlac and STP-McKay

STP-Senlac and Phase 1 are operational but there remains a risk that the Corporation may have interruptions or reductions of operations or increased costs or decreased margins. These risks include, without limitation:

- prevailing commodity prices or other economic factors resulting in uneconomic operations;
- reduced access to diluent;
- facility performance falling below expected levels of output or efficiency;
- breakdown or failure of equipment or processes;
- reservoir performance;

- errors in construction or design affecting operations;
- labour disputes, disruptions or declines in productivity;
- increases in materials, services, transportation or labour costs;
- non-performance by, or financial failure of, third-party contractors;
- disruption or delays in availability of transportation services;
- energy supply disruption;
- conditions imposed by regulatory approvals;
- increased royalty payments based on the price of WTI or further changes to royalty regimes;
- shortages of, or delays in, accessing required equipment and services;
- permit requirement violation;
- transportation or operations accidents;
- delays induced by weather; and
- catastrophic events such as fire, earthquakes, storms or explosions.

If the Corporation's STP-Senlac and/or Phase 1 SAGD facilities do not operate as planned, the Corporation's revenue, cash flow and earnings may be reduced.

The performance of the Corporation's STP-Senlac and STP-McKay SAGD facilities may differ from the Corporation's expectations. The variances from the Corporation's expectations may include, without limitation:

- the ability to operate at the expected level of throughput or production;
- the need to workover existing wells or the need to drill additional wells;
- infrastructure and pump performance;
- the ability to realize the expected long-term SORs; and
- the reliability or availability of the facilities.

If the facilities do not perform to the Corporation's expectations or as required by regulatory approvals, the Corporation may be required to invest additional capital to correct deficiencies or the Corporation may not be able to produce the expected level of production. If these expectations are not met, the Corporation's revenue, cash flow and earnings could be reduced.

The operating costs of STP-Senlac may vary considerably during the operating period and the operating costs of STP-McKay may vary considerably during start-up and thereafter during the operating period. If they increase, the Corporation's earnings and cash flow may be reduced.

The operating costs of the projects of the Corporation may vary considerably during the operating period. If such costs increase, the Corporation's earnings and cash flow will be reduced. The factors which could affect operating costs include, without limitation:

- the cost of natural gas and electricity;
- the actual SOR required to operate the SAGD well pairs;
- the amount and cost of labour to operate;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance costs of the facilities;
- well performance and pump life;
- workovers or the need to drill additional wells and rig availability;
- severe weather;
- the cost to transport heavy oil, bitumen, diluent and dilbit and the cost to dispose of certain by-products;
- the cost of insurance and the inability to insure for certain types of losses;
- catastrophic events such as fires, earthquakes, storms or explosions;
- the cost of catalyst and chemicals; and
- the cost of complying with regulatory approvals.

The selling price received for bitumen produced at STP-McKay and Phase 1 may vary considerably during the operating period. If certain factors that adversely influence bitumen pricing increase, the Corporation's earnings and cash flow will be reduced. These factors may include, separately or collectively:

- the heavy oil differential;
- the cost of diluent;
- the cost to transport diluent;
- the operation of and access to proximate upgraders;
- the dilbit quality differential; and
- the cost to transport dilbit.

In addition, the absolute price of crude oil prices, as measured by WTI, and U.S./Canadian foreign exchange rates will influence the selling price of bitumen received by the Corporation. A low WTI price and a strong Canadian dollar would negatively impact earnings and cash flow of the Corporation.

Access to diluent supplies at favourable prices may be limited.

Bitumen is characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the processing and transportation of bitumen. A shortfall in the supply of diluent may cause its cost to increase or alternative diluent supplies to be purchased, thereby increasing the cost to transport bitumen to market and correspondingly increasing the Corporation's operating cost and negatively impacting the overall profitability of the Corporation.

In-situ extraction is subject to uncertainty.

Current SAGD technologies for in-situ recovery of bitumen are energy intensive, requiring significant consumption of natural gas or other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The quality and performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology for bitumen is relatively new and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of SAGD operations. Should the Corporation encounter adverse reservoir conditions, bitumen recovery levels achieved by the Corporation using SAGD processes may be negatively affected.

The recovery of bitumen from oil sands is subject to a number of risks and uncertainties, many of which are outside of the Corporation's control.

Recovering bitumen from oil sands involves particular risks and uncertainties. Severe weather conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to the Corporation's facilities or wells and liability to third parties against which the Corporation may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Abandonment and reclamation costs related to STP-Senlac and STP-McKay may be higher than anticipated.

The Corporation will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of STP-Senlac and STP-McKay and reclamation of its lands at the end of its economic life, the cost of which may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate reliably the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In the future the Corporation may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Transportation to and from STP-McKay is subject to certain hazards.

On June 27, 2012, Southern Pacific announced completion of a long-term arrangement to transport its bitumen to the U.S. Gulf Coast via the rail network of CN. Under this arrangement, Southern Pacific expects that it will transport bitumen to market via truck, rail and barge. Normal hazards associated with trucking include the potential for vehicle accidents, road closures resulting from poor weather, spring break up or unusual traffic usage which can cause delays in produced volumes being transported or a shut in of the facility for a period of time. Collisions between vehicles and wildlife remain a significant hazard. Normal hazards associated with transportation by rail include collisions with vehicles and wildlife and rail line breaks. Normal hazards associated with transportation by barge include accidents resulting from poor weather and collisions with other vessels.

Future expansions at STP-McKay, including the completion of Phase 2 and the Phase 1 Expansion, may be subject to delay due to commodity price declines and credit and capital market conditions, regulatory approvals and economic downturns. Expansions may not be completed on time, on budget or at all and once operational, may be subject to delays, interruptions or increased costs that may materially adversely affect the Corporation's results of operations

Future expansion at STP-McKay will be subject to construction stage and financing risks. Additionally, there is a risk that future operations, including expansion of production capacity at Phase 1, may have delays, interruption of operations or increased costs due to many factors, including, without limitation:

- an inability to obtain adequate financing, or financing on terms satisfactory to the Corporation;
- prevailing commodity prices or other economic factors resulting in uneconomic operations;
- shortages of, delays in, and increasing costs for obtaining qualified labour, equipment, construction materials or services;
- labour disputes, disruptions or declines in productivity;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- transportation or construction accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting construction or transportation;
- unforeseen site surface or subsurface conditions;
- disruption in the supply of energy; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The continued recovery from the global economic recession is expected to result in an increase in activity in the Canadian oil sands to the high levels of industrial activity seen prior to 2008. The Corporation's expansion projects will need to compete for equipment, supplies, services, and labour in this environment, which could result in increased costs or, shortages of goods and services that delay progress, or both.

In addition, participation in any additional projects will significantly increase the demands on the Corporation's Management and administrative resources and require significant financing. The Corporation may not be able to effectively manage or finance the additional projects and any failure to do so could have a material adverse effect on the Corporation's business, financial condition or results of operations. Additionally, financing required to fund these expansion projects may not be available on terms and conditions acceptable to the Corporation or at all. See "*Risk Factors - Risks Related to Financing and the Corporation's Indebtedness*".

Risks Relating to the Corporation's Oil Sands and Heavy Oil Operations

The Corporation must obtain and maintain regulatory approvals and comply with stringent environmental laws and regulations. The failure to obtain such approvals and comply with any of these laws and regulations could, among other things, prevent or limit the Corporation's operations or subject the Corporation to substantial liability, which, in turn, could have a material adverse effect on the Corporation's business and financial condition.

The operation and eventual decommissioning of the Corporation's projects and operations, as well as the construction of future oil sands projects, the development of additional projects and reclamation of the lands used in the Corporation's operations, are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued, not repealed, or renewed, or that they will not contain terms and conditions which make the Corporation's projects and operations uneconomic or cause the Corporation to significantly alter its projects and operations. Further, the development, operation and eventual decommissioning of the Corporation's projects and reclamation of the Corporation's lands are and will be subject to approvals, laws and regulations relating to environmental protection and operational safety. Risks of substantial costs and liabilities are inherent in both oil sands and heavy oil recovery and there can be no assurance that substantial costs and liabilities will not be incurred or that the Corporation's projects or heavy oil operations will be permitted to carry on operations. Moreover, it is possible that other developments, such as increased levels of royalties or increasingly strict environmental and safety laws, regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the project's operations could result in substantial costs and liabilities to the Corporation or delays to, or abandonment of, the Corporation's projects and operations, including STP-Senlac, STP-McKay and Red Earth. In addition, no assurance can be given that future environmental approvals, processes, laws or regulations will not adversely impact the Corporation's ability to develop, operate or expand its operations or increase or maintain its production or will not increase the Corporation's unit costs of production for crude oil, natural gas and bitumen.

Alberta has enacted the Climate Change and Emissions Management Act (the "**Act**") and the *Specified Gas Reporting Regulation* which requires all facilities emitting over 50,000 tonnes of carbon dioxide equivalent ("**CO_2e**") annually to report their GHG emissions.

Alberta has also enacted the Specified Gas Emitters Regulation ("**SGER**") which requires all facilities in Alberta emitting over 100,000 tonnes of CO_2e per year to reduce their emissions intensity (total annual emissions per unit of production) by 12 percent from their 2003 - 2005 baseline emissions intensity. New facilities which emit over 100,000 tonnes of CO_2e per year have a graduated reduction obligation of 2 percent per year starting in their fourth year of commercial operation up to a reduction obligation of 12 percent below the emissions intensity in their third year of operation. New facilities are facilities that began operation on or after January 1, 2000 and have completed less than 8 years of commercial operation.

The Phase 1 facilities' first year of operation will be in 2012 and its fourth year of operation will be in 2016. In 2016 the Corporation will begin to reduce its emissions intensity in accordance with the SGER. The Corporation has four options to choose from in order to meet the SGER's reduction requirements, and these are (i) by making improvement to operations that result in reductions; (ii) by purchasing emission performance credits ("**EPCs**") from other sectors or facilities that have reduced their emissions below the required emission intensity reduction levels; (iii) by purchasing off-set credits from other sectors or facilities that have emissions below the 100,000 tonne CO_2e per year threshold and are voluntarily reducing their emissions in Alberta; or (iv) by contributing to the Climate Change and Emissions Management Fund. The Corporation can choose one of these options or a combination thereof.

Canada has been an active participant in the United Nations Framework Convention on Climate Change since its establishment, and has signalled its desire to work with the international partners to negotiate a new fair and effective international climate change agreement for the post-2012 period. On December 5, 2011, Canada announced that it would be withdrawing as a signatory to the Kyoto Protocol.

Previously Canada committed to reducing its economy-wide GHG emissions by 17 percent below 2005 levels by 2020, which is equivalent to reducing Canada's 2020 emissions to 607 megatonnes. This target was set internationally in the Copenhagen Accord, and is aligned with that of the United States. Canada's target was formally reiterated in the Cancun Agreement, adopted in December 2010.

Going forward, the Government has announced that it will focus on a sector-by-sector regulatory approach, beginning with the largest sources of emissions. Given the high degree of economic integration between Canada and the US, Canada has stated that it will be aligned with future US emissions reduction regulations where it is appropriate and in Canada's best interests to do so. This regulatory agenda will continue to be supported by the targeted complementary measure designed to advance Canada's transition to a clean energy economy.

Under Canada's plan to address climate change, actions have been taken regarding two of the largest sources of GHG emissions: the electricity and transportation sectors.

The oil sands industry is expected to be a sector of the economy where the federal Government will regulate GHG emissions next. However, at this time it is not known how or when GHG emissions from the oil sands industry will be regulated or the reductions in emissions that will be required. The Corporation believes that it is reasonably likely that new federal legislation requiring GHG emissions will be enacted in Canada and that such federal legislation could have a material effect on the development of Southern Pacific's assets.

Future federal industrial air pollutant and GHG emission reduction targets, together with provincial emission reduction requirements in Alberta's Act, or emission reduction requirements in future regulatory approvals, may require the reduction of emissions or emissions intensity from the Corporation's operations and facilities, payments to a technology fund or purchase of EPCs or off set credits. The required emission reductions may not be technically or economically feasible to implement and the failure to meet such emission reduction requirements or other compliance mechanisms may materially adversely affect the Corporation's business and result in fines, penalties and the suspension of operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to required levels in the future may significantly increase our operating costs or reduce output of our projects. Emission reduction or off-set credits may not be available for acquisition by our projects or may not be available on an economic basis. There is also the risk that the provincial government could impose additional emission or emission intensity reduction requirements, or that the federal and/or provincial governments could pass legislation which would tax such emissions.

The Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring that was released on February 3, 2012 will involve additional monitoring of air, water, land and biodiversity in the oil sands region beginning in 2012. The outcomes of this additional monitoring may result in new government regulations being enacted that could result in increased costs and additional legal obligations for Southern Pacific's operations.

Operations at STP-Senlac and STP-McKay rely on non-saline subsurface water, which is obtained under licenses from Saskatchewan Environment and Alberta Environment. There can be no assurance that the licenses to withdraw subsurface water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that the Corporation will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the Corporation's projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to the Corporation or at all, or that such additional water will in fact be available to divert under such licenses.

On August 22, 2012, the Government of Alberta approved the LARP. One of the key features of the LARP is the establishment of Conservation Areas. As a result of LARP, the Corporation will be losing approximately 18 sections (gross) or 24%, (16 sections net or 21% net), of its oil sands leases in the Anzac area. None of these oil sands leases that the Corporation will be losing have resource or reserves assigned to them, with a majority of the leases being located along the Christina and Clearwater river valleys, which the Corporation had no plans to develop.

Compensation with respect to cancellation of all or portions of Crown mineral rights agreements will be determined according to the Mineral Rights Compensation Regulation. The Corporation will be in discussion with the Crown regarding compensation for these lost oil sands leases.

The Species at Risk Act ("**SARA**") was enacted by the Government of Canada as a means to manage species of special concern to prevent them from becoming extinct, endangered or threatened. The woodland caribou has been designated as a species under threat in the Province of Alberta. Pursuant to the SARA, lands that fall within Southern Pacific's oil sands leases have been designated as sensitive habitat for caribou. The Corporation has undertaken enhanced operating practices within the designated areas with a view to protecting the threatened caribou population.

It is possible that both the LARP and current or future requirements under the SARA may negatively impact Southern Pacific's access to or its ability to conduct operations on certain resource properties or limit or prohibit development due to environmental limits and thresholds. In addition, the enhanced operating practices undertaken by the Corporation in response to the SARA increase operating costs and such costs may further increase in the future if there are further changes to the prescribed operating practices.

Management estimates and assumptions could vary from actual results.

In preparing consolidated financial statements in conformity with Canadian GAAP (and, in financial years beginning after January 1, 2011, International Financial Reporting Standards ("**IFRS**")), estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Corporation must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful lives of assets, income taxes, stock based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, which could have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Failure to implement required new or improved internal controls could impact the Corporation's results of operations or cause it to fail to meet its reporting obligations.

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent material omissions. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could impact the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and reduce the trading price of the Common Shares.

The Corporation's operating cash flow will be directly affected by the applicable royalty regime.

The Governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which it owns the mineral rights.

A change in the royalty regime resulting in an increase in royalties would reduce the Corporation's cash flow and earnings and could make future capital expenditures or the Corporation's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay the Corporation's debt. Any material increase in royalties would also significantly reduce the value of the Corporation's associated assets.

The Corporation's business may suffer in the event of a loss of key personnel.

The Corporation faces numerous risks due to the stage of its development, as well as certain other factors. The Corporation's success will depend in part on the ability, expertise, judgment, discretion and good faith of the

Corporation's Management and its ability to retain them. The loss of any key personnel may have a material adverse effect on the Corporation's business, financial condition or results of operations.

The Corporation's oil and gas operations are subject to numerous operational hazards and other risks against which the Corporation may not be insured.

The operation of STP-Senlac and STP-McKay are subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation does not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Corporation's operations could be interrupted by natural disasters or other events beyond its control. Losses and liabilities arising from uninsured or under insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

The labour force is limited and the Corporation may not be able to hire all of the labour force required at the compensation levels budgeted for or at all.

The labour force in Alberta and Saskatchewan, and specifically in the Fort McMurray and surrounding area, has at times been limited. The resurgence of activity experienced in the oil sands industry as of late may impact the Corporation's ability to access the necessary skilled labourers to operate STP-Senlac and Phase 1 and to construct and operate Phase 2 and the Phase 1 Expansion in the future, construct other expansion projects and to operate and maintain the Corporation's crude oil and natural gas properties and could have an adverse affect on the Corporation's development plans. The Corporation competes with other oil sands projects for experienced employees and such competition may impact the availability of employees and/or may result in increases to compensation paid to such employees. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs which may adversely affect the Corporation's cash flow and earnings.

Title review will be done in accordance with industry standards but will not guarantee title to the Corporation's properties.

The Corporation's properties were leased from the Crown in Right of Alberta and Saskatchewan and although title reviews will be done according to industry standards prior to the purchase of most crude oil and natural gas producing properties (excluding properties acquired from the Crown in Right of Alberta and Saskatchewan) or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue the Corporation receives. If such were the case, the Corporation's entitlement to the production and reserves associated with such leases could be jeopardized, which could have a material adverse effect on the Corporation's financial condition, results of operations and the Corporation's ability to execute its business plan in a timely manner or at all.

Leases or permits may expire.

The Corporation's properties are held in the form of leases and permits and working interests in leases and permits. If the Corporation or the holder of the lease or permit fails to meet the specific requirement of a lease or permit, the lease or permit may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease or permit will be met. The termination or expiration of the Corporation's leases or permits or the working interests relating to a lease or permit may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Aboriginal peoples may make claims against the Corporation or its properties.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, the Province of Saskatchewan, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which STP-McKay and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Corporation. The Corporation continues to consult with and work with Aboriginal groups.

Capital projects may experience cost overruns.

There is a risk associated with providing cost estimates for major projects. Southern Pacific often provides estimates for its major projects, such as Phase 2 and the Phase 1 Expansion, which encompass the conceptual stage through to final scope design, including detailed engineering cost estimates; however, these projects typically evolve over time and updates for significant timing and cost estimate changes are often required during project construction. At each stage of these major projects, cost estimates involve uncertainties. Accordingly, actual costs can vary from these estimates and these differences can be material. Further there is a risk that maintenance at STP-Senlac or STP-McKay will be required more often than currently planned or that significant capital projects could arise that were not previously anticipated.

Negative public perception of Canada's oil sands may have a negative impact on Southern Pacific's operations and business.

Development of Canada's oil sands has received significant attention in political, media and activist commentary on the subject of climate change, GHG emissions, water usage, harm to aboriginal communities and environmental damages. Public concerns regarding such issues may directly or indirectly have a negative impact on the profitability of Southern Pacific by: (i) motivating extraordinary environmental and emissions regulation by governmental authorities, which could result in changes to Southern Pacific's operating requirements, thereby potentially increasing the cost of operation and reclamation and abandonment; (ii) compelling legislation or policy that limits the purchase of crude oil produced from Canada's oil sands by governments or other consumers, which in turn, may limit the market for Southern Pacific's dilbit and reduce its price; and (iii) resulting in proposed pipelines not being able to receive the necessary permits and approvals, which, in turn may limit the market for Southern Pacific's dilbit and reduce its price.

Risks Relating to Financing and the Corporation's Indebtedness

The Corporation's overall level of indebtedness represents a large portion of its capitalization and could constrain its operations.

The Corporation has a significant amount of indebtedness and the Corporation's level of indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- make it more difficult for the Corporation to conduct its operations;
- increase the Corporation's vulnerability to general adverse economic and industry conditions;
- require the Corporation to dedicate a portion of its cash flow from operations to service payments on its indebtedness, thereby reducing the availability of the Corporation's cash flow to fund working capital, capital expenditures and other general corporate purposes;
- limit the Corporation's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Corporation at a competitive disadvantage compared to its competitors that have less debt; and
- limit the Corporation's ability to borrow additional funds on commercially reasonable terms, if at all, to meet its operating expenses and for other purposes.

The Corporation's ability to make scheduled repayments or to re-finance its debt obligations depends upon its financial and operating performance.

The Corporation's ability to make scheduled repayments or to re-finance its debt obligations depends in part upon the Corporation's financial and operating performance, which in turn depend partially upon prevailing industry and general economic conditions which are beyond its control. There can be no assurance that the Corporation's operating performance, cash flow and capital resources will be sufficient to service and/or repay its debt in the future, in which case the Corporation may be required to sell assets to repay its debt, defer capital expenditures or raise additional debt or equity, to the extent available.

If the Corporation is unable to obtain sufficient funding, its ability to expand its operations may be impaired.

The Corporation's ongoing activities may not generate sufficient cash flow from operations to fund future exploration, development or acquisition programs. The Corporation may require additional external financing and the amount of such financing may be significant. While there are various financing options available to the Corporation, including the sale of new equity or debt or joint ventures, sale of working interests or other alternatives, the Corporation's ability to arrange such financing in the future may depend in part upon the prevailing capital market conditions, as well as the Corporation's business performance. There can be no assurance that the Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation or at all. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit interests in certain properties, miss certain acquisition opportunities and reduce or terminate operations. This may result in the Corporation not being able to replace its reserves or maintain production, which will have an adverse effect on its financial position. In addition, if the Corporation obtains additional financing by the issuance of shares from treasury, control of the Corporation may change and existing shareholders may suffer additional dilution.

From time to time the Corporation may enter into transactions to acquire assets. Such transactions may be financed partially or wholly with debt, which may temporarily increase the Corporation's debt levels above industry standards.

Risks Relating to Reserves and Resources

Undue reliance should not be placed on estimates of reserves and resources, since these estimates are subject to numerous uncertainties. The Corporation's actual reserves could be lower than such estimates.

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and quantities of Contingent and Prospective Resources and future net revenues to be derived therefrom, including many factors beyond the Corporation’s control. The reserve, resource and future net revenue information presented by the Corporation represent estimates only. The reserves, resources and estimated future net cash flow from the Corporation’s STP-McKay and STP-Senlac properties have been independently evaluated by GLJ with an effective date of June 30, 2012. The resources and estimated future net cash flow from the Corporation’s emerging oil sands properties (Anzac, Ells, Hangingstone West and Leismer South) have been independently evaluated by GLJ with an effective date of June 30, 2012. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves and resources, timing and amount of capital expenditures, marketability of production, future prices of blended bitumen, crude oil and natural gas, operating costs, well abandonment values, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the Corporation’s control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations, deterministic methods and upon analogy to similar types of reserves and resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves or resources.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of crude oil and natural gas prices may render uneconomic the recovery of certain grades of bitumen.

The present value of estimated future net revenue referred to herein should not be construed as the fair market value of estimated bitumen, crude oil and natural gas reserves and bitumen resources attributable to the Corporation's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for bitumen, crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

References to “resources,” “Contingent Resources” and “Prospective Resources” in this document do not constitute, and should be distinguished from, references to “reserves”. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or lack of markets. Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For Contingent Resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the “chance of development.” Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the “chance of discovery.” Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components - the chance of discovery and the chance of development. The estimates of Prospective Resources contained in this Annual Information Form have been risked for the chance of discovery and hence are considered partially risked estimates.

The Corporation's cash flow and earnings growth are highly dependent upon the Corporation developing its current reserve base and converting its resource base to reserves and production.

The Corporation's reserves, resources and production and, therefore, the Corporation's cash flow and earnings, are dependent upon the Corporation developing its current reserve and resource base to production and cash flow and discovering or acquiring additional reserves and resources. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand its reserves and resources will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves and resources to replace production at commercially feasible costs.

Risks Relating to Third Parties

The Corporation may be subject to conflicting interests with joint venture partners.

Management of the Corporation may attempt to identify industry participants and negotiate transactions whereby other enterprises will join with the Corporation to conduct joint venture activity to develop the Corporation's oil sands properties or infrastructure for such projects. Current capital market conditions make this process more challenging and time consuming than under more buoyant economic circumstances, resulting in the Corporation possibly having to bring participants into its planned activities on less attractive terms than might otherwise have been negotiated. There can be no assurances as to the timing or completion of related terms of possible joint venture arrangements.

Joint venture arrangements must be negotiated with third parties who will generally have objectives and interests that may not coincide with Southern Pacific's interests and may conflict Southern Pacific's interests. Unless the parties are able to compromise these conflicting objectives and interests in a mutually acceptable manner, arrangements with these third parties will not be consummated.

In certain circumstances, the concurrence of joint venture partners may be required for various actions. Other parties influencing the timing of events may have priorities that differ from Southern Pacific's, even if they generally share Southern Pacific's objectives. Demands by or expectations of joint venture partners and others may affect Southern Pacific's participation in such projects or its ability to obtain or maintain necessary licenses and other approvals or the timing of undertaking various activities or operations.

The Corporation is subject to third party credit risks through its contractual arrangements.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current and future joint venture partners that are marketers of its crude oil, bitumen, natural gas, natural gas liquids production and its refined petroleum products. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit condition in the industry and of a potential joint venture partner may impact a potential joint venture partner's willingness to participate in a future Southern Pacific capital program.

The Corporation is subject to extensive government regulation. The Corporation may have to expend substantial amounts for compliance with regulations or the Corporation may become liable for failure to comply with regulations.

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, the use of sub-surface water in the Corporation's operations, as well as other matters. The industry is also subject to regulation by federal, provincial and municipal governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

To date, the Corporation believes STP-Senlac and Phase 1 have received all of the approvals currently required. However, before proceeding with Phase 2, the Phase 1 Expansion or its other projects, the Corporation must obtain all required regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the project and increased costs, all of which could have a material adverse affect on the Corporation, STP-Senlac and STP-McKay and ongoing exploration activity are also subject to periodic inspections by regulatory authorities to ensure the Corporation's compliance with the conditions of regulatory approvals. Negative inspection results may lead to the imposition of fines or penalties or the suspension or rescission of the project's regulatory approvals.

The Corporation's operations depend on infrastructure owned and operated by third parties and on services provided by third parties. Failure by these third parties to provide infrastructure and services required by the Corporation could have a material adverse effect on the Corporation's business and results of operations.

The Corporation depends on certain infrastructure owned and operated or to be constructed by others and on services provided by third parties, including, without limitation, processing facilities, pipelines or rail lines for the transportation of products to the market, the transportation of natural gas to STP-Senlac and STP-McKay, disposal pipelines, electrical grid transmission lines for the provision and/or sale of electricity to the Corporation, roads, airstrips, terminals and vessels. The failure of any or all of these third parties to supply utilities, services, or in connection with STP-Senlac and STP-McKay, to construct necessary infrastructure, on a timely basis and on acceptable commercial terms will negatively impact the Corporation's operations and financial results. Generally, the Corporation also depends on third parties to provide numerous services to it in connection with its operations, including transportation services, drilling and well services, and the failure of such third parties to provide such services will also negatively impact the Corporation's operations and financial results.

The Corporation will be trucking diluent to, and dilbit from, STP-McKay and is also anticipating using rail to ship diluent from and dilbit to markets. The ability to deliver diluent to STP-McKay and ship dilbit to markets is dependent on, among other things, access to trucks and drivers, rail cars and railroads and may be impacted by accidents, weather delay and general road conditions. Delays or the inability to deliver diluent to STP-McKay or ship dilbit to market could have a negative impact on the Corporation's results of operations and cash flow.

Recent disruptions in pipeline services have resulted in apportionment on volumes, greater supply of heavy crude oil and dilbit in local markets and increased demand and cost of alternative sources of transportation for the Corporation's products. Future transportation and infrastructure issues may adversely affect the Corporation's results of operations and cash flow.

Changes in tax laws may adversely affect the Corporation, STP-Senlac, STP-McKay and future expansion phases.

Income tax laws or government incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects the Corporation, its operations and future expansion plans.

The Corporation's industry is highly competitive and many of its competitors have greater resources than the Corporation does.

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests and the distribution and marketing of petroleum products. The Corporation will compete with producers of bitumen, synthetic crude oil blends and other producers of oil and natural gas. Some of the conventional producers have lower operating costs than the Corporation is anticipated to have, and many of them have greater resources than the Corporation has. Certain of the Corporation's competitors may have greater resources to source, attract, and retain the personnel, materials and services that the Corporation will require to conduct its operations or to conduct expansions. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than the Corporation have announced plans to enter the oil sands business and begin production of bitumen, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen or synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, the Corporation's results of operations and cash flow.

Other Risks Affecting the Corporation's Business

Political risks and terrorist attacks may impact the Corporation's results of operations

The marketability and price of bitumen is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil. Any particular event could result in a material decline in prices and therefore could have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

In addition, the long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. The possibility that infrastructure and other facilities, such as pipelines, terminals and refineries, may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks have resulted in, and are expected to continue to result in, increased costs to the Corporation's business. Furthermore, any interruption in the services provided by infrastructure on which the Corporation relies as a result of a terrorist attack would have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

There are potential conflicts of interest to which some of the Corporation's directors and officers will be subject in connection with the Corporation's operations.

Some of the directors and officers of the Corporation are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. From time to time, the Corporation may jointly participate in exploration and development activities with one or more corporations with which a director or officer of the Corporation may be involved. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

The Corporation is exposed to risks related to insurance.

The Corporation's property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Corporation.

The Corporation is exposed to risks related to litigation.

In the normal course of the Corporation's operations, it may become involved in, named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Corporation's business operations, which could adversely affect its financial condition.

Future acquisition activities may have adverse effects on the Corporation.

The Corporation may seek to acquire additional companies or assets in the Corporation's industry. The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets, and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Corporation's acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

DIVIDENDS

The Corporation has not declared or paid any dividends in the three most recently completed financial years. Any decision to pay dividends on the Common Shares will be made by the board of directors of the Corporation on the basis of the Corporation’s earnings, financial requirements and other conditions existing at the relevant time.

DESCRIPTION OF SHARE CAPITAL

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares, issuable in series. As of June 30, 2012, an aggregate of approximately 341.3 million Common Shares were issued and outstanding. As of September 24, 2012, an aggregate of approximately 341.6 million Common Shares were issued and outstanding.

The holders of the Common Shares are entitled to receive notice of and attend any meeting of the Corporation's shareholders and are entitled to one vote for each Common Share held (except at meetings where only the holders of another class of shares are entitled to vote). Subject to the rights attached to any other class of shares, the holders of the Common Shares are entitled to receive dividends, if, as and when declared by the board of directors of the Corporation and are entitled to receive the remaining property upon liquidation of the Corporation.

Preferred Shares

The Corporation is authorized to issue an unlimited number of preferred shares ("**Preferred Shares**"). As of both June 30, 2012 and September 24, 2012, no Preferred Shares were issued and outstanding.

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the board of directors of the Corporation, who may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The Preferred Shares of each series shall, with respect to dividends, liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding up its affairs, shall be entitled to preference over the Common Shares and the shares of any other class ranking junior to the Preferred Shares. The Preferred Shares of any series may also be given such other preferences and priorities over the Common Shares and any other shares of the Corporation ranking junior to such series of Preferred Shares.

2011 Debentures

The 2011 Debentures are limited to $172,500,000 aggregate principal amount. As of September 24, 2012, 2011 Debentures in the aggregate principal amount of $172,500,000 were issued and outstanding.

The 2011 Debentures mature on June 30, 2016 at a price of $1,000 per 2011 Debenture and bear interest at an annual rate of 6.00% payable semi-annually on June 30 and December 31 of each year, commencing June 30, 2011.

Holders may convert their 2011 Debentures into Common Shares at any time prior to the close of business on the earlier of: (i) the business day immediately preceding the Maturity Date; or (ii) if called for redemption, on the business day immediately preceding the date specified by the Corporation for redemption of the Debentures, based on an initial conversion ratio of 465.1163 Common Shares per $1,000 principal amount of Debentures (equivalent to an initial conversion price of $2.15 per Common Share); or (iii) if subject to repurchase pursuant to a Change of Control, as defined below, on the business day immediately preceding the payment date, subject to the satisfaction of certain conditions. The conversion rate is subject to adjustment in certain circumstances described below.

The 2011 Debentures are not redeemable prior to June 30, 2014. On or after June 30, 2014, but prior to June 30, 2016, the 2011 Debentures will be redeemable, in whole or in part, at a price equal to the principal amount thereof, plus accrued and unpaid interest, at the Corporation's sole option on not more than 60 days' and not less than 30 days' prior notice, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice is given") is not less than 130% of the Conversion Price.

The 2011 Debentures are direct, subordinated, unsecured obligations of the Corporation and will rank equally with one another and with all other existing and future unsecured indebtedness of the Corporation, and except as prescribed by law as described therein. The Indenture will not restrict the Corporation or its subsidiaries from incurring additional indebtedness or from mortgaging, pledging or charging its properties to secure any indebtedness or liabilities.

MARKET FOR SECURITIES

Common Shares

The following table sets forth the monthly high and low closing prices and volumes of the trading of the Common Shares for the periods indicated (as reported by the TSX). The Common Shares trade under the symbol "STP" on the TSX.

Period	High	Low	Volume
2011			
July	$1.76	$1.54	16,253,247
August	$1.65	$1.26	16,360,403
September	$1.44	$1.13	17,708,894
October	$1.50	$0.87	15,933,301
November	$1.49	$1.26	8,672,502
December	$1.46	$1.19	18,996,488
2012			
January	$1.69	$1.40	34,025,116
February	$1.87	$1.62	14,382,606
March	$1.92	$1.56	25,854,776
April	$1.69	$1.45	12,734,396
May	$1.70	$1.46	15,603,211
June	$1.57	$1.22	24,380,859
July	$1.49	$1.13	16,013,221
August	$1.59	$1.39	15,052,010
September 1 – 21	$1.55	$1.41	11,736,605

2011 Debentures

The following table sets forth the monthly high and low closing prices and volumes of the trading of the 2011 Debentures for the periods indicated (as reported by the TSX). The 2011 Debentures trade under the symbol "STP.DB" on the TSX.

Period	High	Low	Volume
2011			
July	$111.00	$102.65	2,109,000
August	$106.00	$94.50	31,440,000
September	$98.00	$89.18	13,246,000
October	$98.50	$80.87	17,926,000
November	$97.50	$92.00	4,293,000
December	$95.91	$93.00	6,600,000
2012			
January	$106.00	$94.81	7,731,000
February	$109.00	$104.00	4,045,000
March	$111.00	$105.25	10,098,000
April	$106.14	$101.80	5,425,000
May	$107.30	$103.40	7,364,000
June	$105.00	$98.71	9,155,000
July	$105.25	$99.50	5,271,000
August	$106.97	$104.00	5,686,000
September 1 – 21	$107.15	$104.75	5,678,000

PRIOR SALES

The following table summarizes the issuances of Common Shares or securities convertible into Common Shares for the 12-month period prior to the date hereof.

Date of Issuance	Securities	Number of Securities	Price per Security
July 11, 2011	Options	50,000	$1.60[(2)]
July 12, 2011	Common Shares[(1)]	100,000	$0.50
July 18, 2011	Options	210,000	$1.56[(2)]
July 25, 2011	Options	125,000	$1.73[(2)]
August 15, 2011	Options	30,000	$1.48[(2)]
August 21, 2011	Options	20,000	$1.32[(2)]
August 29, 2011	Options	75,000	$1.26[(2)]
September 1, 2011	Options	35,000	$1.40[(2)]
September 6, 2011	Options	60,000	$1.37[(2)]
September 7, 2011	Options	30,000	$1.67[(2)]
September 20, 2011	Common Shares[(1)]	260,000	$0.50
September 21, 2011	Common Shares[(1)]	40,000	$0.56
October 3, 2011	Options	20,000	$1.20[(2)]
October 17, 2011	Options	75,000	$1.24[(2)]
October 27, 2011	Options	20,000	$1.31[(2)]
November 1, 2011	Options	15,000	$1.47[(2)]
November 9, 2011	Options	30,000	$1.39[(2)]
November 15, 2011	Common Shares[(1)]	260,000	$0.50
November 21, 2011	Options	90,000	$1.40[(2)]
November 24, 2011	Common Shares[(1)]	100,000	$0.50
November 26, 2011	Options	20,000	$1.29[(2)]
November 28, 2011	Options	200,000	$1.29[(2)]
December 1, 2011	Options	30,000	$1.46[(2)]
December 5, 2011	Options	30,000	$1.41[(2)]
December 19, 2011	Options	45,000	$1.30[(2)]
December 28, 2011	Common Shares[(1)]	5,000	$0.56
January 10, 2012	Common Shares[(1)]	45,000	$0.56 - $1.20
January 16, 2012	Options	100,000	$1.59[(2)]
January 18, 2012	Options	90,000	$1.58[(2)]
January 25, 2012	Options	30,000	$1.57[(2)]
January 26, 2012	Options	60,000	$1.57[(2)]
February 8, 2012	Options	30,000	$1.73[(2)]
February 29, 2012	Options	80,000	$1.83[(2)]
February 13, 2012	Common Shares[(1)]	285,000	$0.77 - $1.20
February 23, 2012	Common Shares[(1)]	320,000	$0.56 - $1.20
March 5, 2012	Common Shares[(1)]	25,000	$1.38
March 6, 2012	Common Shares[(1)]	257,500	$0.56
March 7, 2012	Common Shares[(1)]	107,500	$0.56
March 7, 2012	Options	60,000	$1.86[(2)]
March 12, 2012	Options	100,000	$1.86[(2)]
March 14, 2012	Options	30,000	$1.80[(2)]
March 28, 2012	Options	75,000	$1.73[(2)]
April 1, 2012	Options	85,000	$1.64[(2)]
April 4, 2012	Options	60,000	$1.66[(2)]
April 16, 2012	Options	30,000	$1.51[(2)]
April 28, 2012	Options	30,000	$1.55[(2)]

May 8, 2012	Common Shares[(1)]	28,200	$1.00
May 9, 2012	Options	30,000	$1.59[(2)]
May 28, 2012	Options	75,000	$1.64[(2)]
May 30, 2012	Options	30,000	$1.60[(2)]
June 1, 2012	Options	90,000	$1.52[(2)]
June 4, 2012	Options	20,000	$1.42[(2)]
June 6, 2012	Options	60,000	$1.41[(2)]
June 13, 2012	Options	60,000	$1.52[(2)]
June 27, 2012	Options	30,000	$1.25[(2)]
June 29, 2012	Options	5,243,000	$1.27[(2)]
July 1, 2012	Options	30,000	$1.27[(2)]
July 4, 2012	Options	30,000	$1.32[(2)]
July 18, 2012	Options	30,000	$1.39[(2)]
August 1, 2012	Options	30,000	$1.40[(2)]
August 22, 2012	Options	30,000	$1.54[(2)]
August 27, 2012	Options	15,000	$1.50[(2)]
August 27, 2012	Common Shares[(1)]	46,100	$0.77
August 28, 2012	Common Shares[(1)]	153,900	$0.77
August 29, 2012	Common Shares[(1)]	50,000	$0.77
August 29, 2012	Options	30,000	$1.51[(2)]
September 13, 2012	Common Shares[(1)]	500	$1.47
September 19, 2012	Common Shares[(1)]	30,000	$1.20

Notes:
(1) Represents Common Shares that were issued pursuant to outstanding Options.
(2) Represents the exercise price per Option.

ESCROWED SECURITIES

The number of Common Shares and Warrants held in escrow and the percentage that number represents of the outstanding securities of the Corporation as of June 30, 2012 is as follows:

Designation of Class	Number of Securities Held in Escrow	Percentage of Class
Common Shares	0	0%
Warrants	0	0% of the Warrants

DIRECTORS AND OFFICERS

The following table sets forth the names and municipalities of residence of the current directors and executive officers of the Corporation, their respective positions and offices with the Corporation and date first appointed or elected as a director and/or officer and their principal occupation(s) within the past five years.

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Byron Lutes, P.Eng Calgary, Alberta, Canada	Chief Executive Officer, President and Director	Mr. Lutes is Chief Executive Officer and President of the Corporation. Mr. Lutes is a Professional Engineer with over 26 years of experience in the oil and gas sector including 14 years in senior officer roles. Prior to joining Southern Pacific, Mr Lutes was the Vice President, Operations at Mancal Energy Inc. Previous to that appointment, Mr Lutes was the Vice President, Engineering at Hunt Oil Company of Canada and Newport Petroleum Corporation.	January 7, 2008 (Officer) April 29, 2009 (Director and CEO)
David M. Antony, CA(2) Calgary, Alberta, Canada	Chairman and Director	Mr. Antony is a Chartered Accountant and is currently the Chairman of the board of the Corporation. Mr. Antony has over 18 years experience in assisting companies in structuring transactions, accessing capital, and corporate governance. In the last five years, Mr. Antony has been Chief Executive Officer of Southern Pacific Resource Corp. (from 2006 to May 2009). Prior thereto, Mr. Antony was a partner at an accounting firm. He is currently Chief Executive Officer of Blackhawk Resource Corp. (since February, 2009).	March 9, 2006
Jon P. Clark, M.Sc., Geo.(3) Calgary, Alberta, Canada	Director	Mr. Clark has been the Exploration Manager for Bounty, a private oil and gas exploration company, since 1996. Mr. Clark is also an employee of Bounty and Nutcracker Holdings Ltd.	November 17, 2006
Tibor Fekete, P.Eng(3) Calgary, Alberta, Canada	Director	Mr. Fekete is the President of Synerg Resources Ltd. and is a professional engineer with over 51 years experience in the oil and gas industry. Mr. Fekete founded and operated T. Fekete and Associates Inc., a leading reservoir engineering firm.	March 9, 2006
J. Ward Mallabone, LLB, B.Comm(1)(2) Calgary, Alberta, Canada	Director	Mr. Mallabone is the President, Chief Executive Officer and Founder of Priviti Capital Corporation, an oil and gas private equity firm. Prior thereto he was the Chief Operating Officer and one of the principals of the EnerVest Group of companies. Mr. Mallabone has over 21 years of experience in the oil and gas sector, most of that on the investment management side.	November 17, 2006

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Sid Dykstra, P.Eng(2)(3) Calgary, Alberta, Canada	Director	Mr. Dykstra is the President and Chief Executive Officer of Bergen Resources Inc., a private oil and gas company. Prior thereto, Mr. Dykstra was the Chief Executive Officer of Cinch Energy Corp. from November 2009 to July 2011 and was the President and Chief Executive Officer of OPTI Canada Inc. from June 2001 until April 2009. From June 2000 to March 2001, Mr. Dykstra was the President of Hunt Oil Company of Canada Inc. Mr. Dykstra, a co-founder of Newport Petroleum Corporation, was the President and Chief Operating Officer of Newport Petroleum Corporation from 1997 to 2000. Mr. Dykstra is a past Governor of the Canadian Association of Petroleum Producers and is a professional engineer in Alberta.	December 2, 2009
Kenneth N. Cullen, CA(1) Calgary, Alberta, Canada	Director	Mr. Cullen is a chartered accountant who served as a partner of Deloitte & Touche LLP for 30 years, including 24 years in Calgary and six in Vancouver, until his retirement in 2006 He practiced in the Assurance and Advisory (Audit) group. Mr. Cullen is also on the board of Birchcliff Energy Ltd.	March 23, 2011
Ross D.S. Douglas, P.Eng, FCAE, ICD.D(1) Calgary, Alberta, Canada	Director	Mr. Douglas is the President and Chief Executive Officer of Mancal Corporation, a private holding company in Calgary. He is currently a director of the Corporation and KMC Mining Corporation. He is active in a number of industry organizations including the Canadian Association of Petroleum Producers, Canadian Centre for Energy Information, the Energy Resources Conservation Board Chairman's Advisory Committee, the Canadian Academy of Engineering and the Industry Advisory Committee for the Schulich School of Engineering at the University of Calgary. Mr. Douglas has also served as Chairman CAPP, and as a member of the Energy Utilities Board Chairman's Advisory Committee. He has served as President, Chief Executive Officer and a member of the Board of Atlantis Resources and Highridge Exploration, and as a board member for Arawak Energy, Deepwell Energy Services Trust, Altius Energy and the Foundation for Energy Education and Research in Calgary.	May 9, 2011
Howard Bolinger, CA Calgary, Alberta, Canada	Chief Financial Officer	Mr. Bolinger is the Chief Financial Officer of the Corporation. Mr. Bolinger is a Chartered Accountant and he has over 17 years of experience in corporate finance. He was the Chief Financial Officer of Proventure Income Fund, a public income trust listed on the TSXV from its inception in December 2005 until May 2006. He was also the Chief Financial Officer of Cervus LP, a public limited partnership listed on the TSXV from its inception in April 2003 until March 2006. Prior to that he was Chief Financial Officer of Cervus Corporation, a public company listed on the TSXV from April 2000 to December 2005.	October 9, 2007

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Ronald Clarke, P.Eng Calgary, Alberta, Canada	Chief Operating Officer	Mr. Clarke, a professional engineer, has worked with Canadian energy company Suncor Energy Inc. for more than 26 years in many facets of the oil and natural gas business in Western Canada. During his last three years, Mr. Clarke has worked on Suncor's Firebag steam-assisted gravity drainage or SAGD project, serving most recently as General Manager of the Firebag Asset Team. Mr. Clarke has headed the reservoir, geology and production engineering activities for both the base assets and the resource development strategy.	June 1, 2010
Glenn Miller, PSL Calgary, Alberta, Canada	Vice President, Land & Regulatory Affairs	Mr. Miller is the Vice President, Land & Regulatory Affairs and has been with the Corporation since June, 2008. Mr. Miller has 18 years of direct energy related experience and has previously held land management and regulatory affairs positions with MGM Energy, APF Energy and Hunt Oil Company.	May 29, 2009
Jeffrey A. Barefoot, P.Eng. Calgary, Alberta, Canada	Vice President, Business Development	Mr. Barefoot is the Vice President, Business Development of the Corporation. Mr. Barefoot has been with the Corporation since June, 2008. Prior thereto, Mr. Barefoot was a founder of Rochester, a junior oil sands company, and held the position of Vice President, Engineering. He has held several other senior-level industry positions including Senior Exploitation Engineer with Thunder Energy Trust, Senior Operations Engineer with MEC Operating Company and Development Engineer with Talisman Energy. Mr. Barefoot is a graduate of the University of Calgary with a Bachelor of Science in Chemical Engineering, as well as a Masters in Business Administration. He is a registered professional engineer with the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and has been employed in the oil and gas industry for over 18 years.	November 3, 2009
Chad Harris, M.Sc. Calgary, Alberta, Canada	Vice President, Exploration	Mr. Harris is the Vice President, Exploration of the Corporation. Mr. Harris has been with the Corporation since December 2009. His most recent position was Senior Geologist for Breaker Energy Ltd., a TSX listed junior conventional oil company that sold to NAL Resources Trust in 2009. Prior to this, Mr. Harris was employed as a geologist at Canadian Natural Resources ("**CNRL**") for 8 years. At CNRL he worked on the exploration and development of the Brintnell Wabiskaw medium oil field, the Peace River Bluesky heavy oil deposit, and the Horizon Project oil sands mine. Mr. Harris received a Master of Science Degree from the University of Alberta for his thesis on the characterization and thermal recovery potential of McMurray oil sand in Northern Alberta.	May 9, 2011

Name and Place of Residence	Office Held	Principal Occupation During Last Five Years	Date First Appointed
Wayne Beatty, P.Eng. Calgary, Alberta, Canada	Vice President, Resource Development	Mr. Beatty is the Vice President, Resource Development. Mr. Beatty has 31 years of experience in the oil and gas industry, primarily in the areas of reservoir engineering, reserve evaluations and project economics. He joined the Corporation in November 2009 as Manager, Reservoir Engineering. Prior to that, Mr. Beatty was Manager, Reserves and Special Projects at Grizzly Resources Ltd. where he was responsible for conducting all reservoir engineering and project economic evaluations for the company's domestic projects and an offshore project in West Africa. Prior to that, Mr. Beatty held Senior Exploitation Engineer positions at PrimeWest Energy Trust, Hunt Oil Canada, PetroCanada, Amerada Hess Canada, and Norcen Energy Resources. He also held the position of Manager, Exploitation at Newport Petroleum Corp. prior to acquisition of the company by Hunt Oil. Mr. Beatty received his Bachelor of Science Degree in Chemical Engineering from the University of Calgary in 1981.	July 1, 2011
Mike O'Krancy, P.Eng. Calgary, Alberta, Canada	Vice President, Projects	Mr. O'Krancy is the Vice President, Projects. Prior to his appointment thereto, Mr. O'Krancy was employed by Southern Pacific for approximately two years in the capacity of Manager, Projects and was in charge of the successful construction of STP-McKay. Mr. O'Krancy has been a project manager with Suncor Energy Inc. (from January 2006 to September 2010) and a project engineer with WorleyParsons Canada (from August 2000 to January 2006).	July 1, 2012
Trevor P. Wong-Chor, LLB Calgary, Alberta, Canada	Corporate Secretary	Since September 17, 2004, Barrister and Solicitor with Davis LLP.	March 9, 2006

Notes:
(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Compensation Committee.
(3) Member of the Reserves Committee.

The directors listed above will hold office until the next annual meeting of the Corporation or until their successors are elected or appointed.

As at September 24, 2012, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3.57 million Common Shares or approximately 1% percent of the issued and outstanding Common Shares of the Corporation. Information as to holdings of insiders of the Corporation may be found on www.sedi.ca.

Corporate Cease Trade Orders or Bankruptcies

Other than as set forth below, no director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within 10 years before the date of this Annual Information Form, has been, a director or executive officer of any corporation that, while that person was acting in that capacity:

- was the subject of a cease trade or similar order, or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days;

- was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the corporation being the subject of a cease trade or similar order or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

- within a year of that person ceasing to act in such capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Howard Bolinger was a director of Pure Lean Inc. Pure Lean Inc. was subject to a cease trade order from the Alberta Securities Commission and British Columbia Securities Commission for failure to file financial statements. The cease trade order was issued on July 27, 2004 by the British Columbia Securities Commission and on August 13, 2004 by the Alberta Securities Commission.

Personal Bankruptcies

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has within 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person.

Penalties or Sanctions

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to:

a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain directors and officers of the Corporation and its subsidiaries are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Some of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation. In particular, certain of the directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE INFORMATION

The Audit Committee is a committee of the board of directors of the Corporation to which the board of directions delegates its responsibility for oversight of the financial reporting process. The Audit Committee is also responsible for managing, on behalf of the shareholders, the relationship between the Corporation and the external auditor.

Pursuant to National Instrument 52-110 — *Audit Committees* ("**NI 52-110**") the Corporation is required to disclose certain information with respect to its Audit Committee, as summarized below.

Audit Committee Terms of Reference

The Corporation must, pursuant to NI 52-110, have a written charter which sets out the duties and responsibilities of its Audit Committee. The terms of reference of the Audit Committee is attached hereto as Schedule C.

Audit Committee Composition

The following are the members of the Audit Committee:

Kenneth N. Cullen(1)	Independent(2)	Financially Literate(2)
Ross D.S. Douglas	Independent(2)	Financially Literate(2)
J. Ward Mallabone	Independent(2)	Financially Literate(2)

Notes:

(1) Chairman.
(2) As defined by NI 51-102.

Relevant Education and Experience

All of the members of the Audit Committee have been either directly involved in the preparation of the financial statements, filing of quarterly and annual financial statements, dealing with auditors, or as a member of the Audit Committee. All members have the ability to read, analyze and understand the complexities surrounding the issuance of financial statements.

Kenneth N. Cullen

Mr. Cullen is a chartered accountant who served as a partner of Deloitte & Touche LLP for 30 years, including 24 years in Calgary and six in Vancouver, until his retirement in 2006 He practiced in the Assurance and Advisory (Audit) group. Mr. Cullen is also on the board of Birchcliff Energy Ltd.

Ross D.S. Douglas

Mr. Douglas is the President and Chief Executive Officer of Mancal Corporation, a private holding company in Calgary. He has extensive experience reviewing and overseeing the preparation of financial statements.

J. Ward Mallabone

Mr. Mallabone is the President, Chief Executive Officer and Founder of Priviti Capital Corporation, an oil and gas private equity firm. Prior thereto he was the Chief Operating Officer and one of the principals of the EnerVest Group of companies. Mr. Mallabone has over 21 years of experience in the oil and gas sector, most of that on the investment management side. Mr. Mallabone holds his Bachelor of Commerce Degree from the University of British Columbia and Bachelor of Laws from the University of Calgary.

Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on:

a) the exemption in section 2.4 of NI 52-110 (De Minimis Non-audit Services);

b) the exemption in section 3.2 of NI 52-110 (Initial Public Offerings);

c) the exemption in section 3.4 of NI 52-110 (Events Outside Control of Members);

d) the exemption in section 3.5 of NI 52-110 (Death, Disability or Resignation of Audit Committee Members); or

e) an exemption from NI 52-110, in whole or in part, granted under Part 8 of NI 52-110.

Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on:

a) the exemption in subsection 3.3(2) of NI 52-110 (Controlled Companies); or

b) the exemption in section 3.6 of NI 52-110 (Temporary Exemption for Limited and Exceptional Circumstances).

Reliance on Section 3.8

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied section 3.8 of NI 52-110 (Acquisition of Financial Literacy).

Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

Pre-Approval Policies and Procedures

The Audit Committee had adopted specific policies and procedures for the engagement of non-audit services as described above under the heading "External Auditors" in the terms of reference of the Audit Committee is attached hereto as Schedule C.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditors in each of the last two fiscal years for audit and other fees are as follows:

Financial Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
2012	$222,500	$139,000	Nil	Nil
2011	$362,400	$8,650	Nil	Nil

Notes:

(1) Audit fees include fees necessary to perform the annual audit and quarterly reviews of the Corporation's consolidated financial statements. Audit fees include fees for review of tax provisions and for accounting

consultations on matters reflected in the financial statements. Audit fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) Audit-related fees include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) Tax fees include fees for all tax services other than those included in audit fees and audit-related fees. This category includes fees for tax compliance, tax planning and tax advice.

(4) All other fees include fees for products and services provided by the Auditor, other than the services reported above.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no material legal proceedings to which the Corporation is a party or of which any of its property is the subject and there are no such material proceedings known to the Corporation to be contemplated.

There are no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during legal proceedings material to the Corporation to which the Corporation is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Corporation to be contemplated during the financial year ended June 30, 2012. Other than as disclosed above, there are no legal proceedings to which the Corporation is a party or of which any of its property is the subject and there are no such proceedings known to the Corporation to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set forth herein, or as previously disclosed, the Corporation is not aware of any material interests, direct or indirect, by way of beneficial ownership of securities or otherwise, of any director or executive officer or any shareholder holding more than 10 percent of the Common Shares or any associate or affiliate of any of the foregoing in any transaction within the three most recently completed financial years or during the current financial year or any proposed or ongoing transaction of the Corporation which has or will materially affect the Corporation.

Jon Clark, an independent director of the Corporation, is a shareholder of Tlell Developments Inc. Tlell Developments Inc. had a 7.5% beneficial interest in Bounty's interest in the Ells block and an 8.5% beneficial interest in Bounty's interest in the McKay Block. On June 1, 2010 the Corporation closed the acquisition of Bounty's entire 20 percent working interest in 59 sections of land in the McKay block. As part of the agreement, Southern Pacific also purchased 20 percent of Bounty's working interest in 32 sections of land adjacent to and near the MacKenzie Block. The board of directors of the Corporation approved the acquisition of Bounty's interests with Mr. Clark abstaining from voting on the matter. The Corporation determined that exemptions from the various requirements of Multilateral Instrument 61-101 and TSXV Policy 5.9 were available for the acquisition. The acquisition was accepted by TSXV.

PROMOTER

David M. Antony may be considered to be a promoter of the Corporation as he took the initiative in reorganizing the Corporation in 2006. As of the date of this Annual Information Form, Mr. Antony beneficially owns 565,417 Common Shares, representing less than 1% of the issued and outstanding Common Shares. Mr. Antony also holds options to purchase:

a) 400,000 Common Shares at an exercise price of $1.90 per Common Share until January 6, 2013;
b) 200,000 Common Shares at an exercise price of $1.05 per Common Share until May 9, 2013;
c) 390,000 Common Shares at an exercise price of $0.10 per Common Share until December 17, 2013;
d) 500,000 Common Shares at an exercise price of $0.56 per Common Share until November 3, 2014;
e) 90,000 Common Shares at an exercise price of $1.20 per Common Share until June 30, 2015;
f) 100,000 Common Shares at an exercise price of $1.47 per Common Share until June 30, 2016; and
g) 100,000 Common Shares at an exercise price of $1.27 per Common Share until June 29, 2017.

Mr. Antony ceased to be Chief Executive Officer of the Corporation on April 29, 2009, when Mr. Lutes assumed such position. Mr. Antony was paid a total of $54,250 during the year ended June 30, 2012. The amount paid to Mr. Antony includes director and committee fees on par with other members of the Board of Directors of the Corporation.

TRANSFER AGENT AND REGISTRARS

Valiant Trust Company is the transfer agent and registrar of the Common Shares and the 2011 Debentures and the register of transfers of Common Shares is maintained in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into during the financial year ended June 30, 2012 (or that were effective in the financial year ended June 30, 2012) that are still in effect.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Deloitte & Touche LLP, Chartered Accountants, the Corporation's current auditor and GLJ, the Corporation's independent engineering evaluators.

Deloitte & Touche LLP is the auditor who prepared the auditor's report for the Corporation's annual financial statements as at and for the year ended June 30, 2012. Deloitte & Touche LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

As at the date of hereof, the partners and associates of Deloitte & Touche LLP, as a group, do not beneficially own any outstanding Common Shares.

As at the date of hereof, the principal evaluators of GLJ, the independent reserves evaluators, as a group, beneficially own, directly or indirectly, less than 1 percent of the outstanding Common Shares.

Trevor Wong-Chor, the Corporate Secretary of the Corporation, is a lawyer at Davis LLP, which law firm provides legal services to the Corporation. As of the date hereof, the associates and partners of Davis LLP, as a group, beneficially own, directly or indirectly, less than 1 percent of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.SEDAR.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the Corporation's information circular for its most recent annual meeting of shareholders.

Additional information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended June 30, 2012, which are also available on SEDAR.

SCHEDULE A

REPORTS OF INDEPENDENT QUALIFIED RESERVES EVALUATOR (FORM 51 -101 F2)

FORM 51-101F2 – Part A
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Southern Pacific Resource Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at June 30, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at June 30, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended June 30, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $MM)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary September 6, 2012	Canada	-	1,593	-	**1,593**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, September 21, 2012

ORIGINALLY SIGNED BY
Jason E. Paul, P. Eng.
Manager, Engineering

FORM 51-101F2 – Part B
REPORT ON RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Southern Pacific Resource Corp. (the "Company"):

1. We have evaluated the Company's resources data as at June 30, 2012. The resource data are estimates of low, best and high estimates of contingent and prospective resources and related future net revenue as at June 30, 2012, estimated using forecast prices and costs.

2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue of the Company (before deduction of income taxes) attributed to best estimate contingent resources and best estimate prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, evaluated by us for the period ended June 30, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator and Resource Category	Description and Preparation Date of Evaluation Report	Location of Resources (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $MM) Audited	Evaluated	Reviewed	Total
Contingent Resources						
GLJ Petroleum Consultants	Corporate Summary September 6, 2012	Canada	-	959	-	**959**
Prospective Resources						
GLJ Petroleum Consultants	Corporate Summary September 6, 2012	Canada	-	389	-	**389**

5. In our opinion, the resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the resources data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that resources are categorized according to the probability of their recovery.
8. Contingent resources evaluated in this report were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent resources entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.
9. Prospective resources were assigned in unexplored regions of the company's acreage. Prospective resources entail commercial risk not applicable to reserves and contingent resources, which have not been included in the net present valuation. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, September 21, 2012

ORIGINALLY SIGNED BY
Jason E. Paul, P. Eng.
Manager, Engineering

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101F3)

Management of Southern Pacific Resource Corp. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at June 30, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) *"Byron Lutes"*
Byron Lutes, Chief Executive Officer, President and Director

(signed) *"Howard Bolinger"*
Howard Bolinger, Chief Financial Officer

(signed) *"David M. Antony"*
David M. Antony, Chairman and Director

(signed) *"Tibor Fekete"*
Tibor Fekete, Director

Dated: September 24, 2012

SCHEDULE C

AUDIT COMMITTEE TERMS OF REFERENCE

SOUTHERN PACIFIC
RESOURCE CORP.

AUDIT COMMITTEE
TERMS OF REFERENCE

SOUTHERN PACIFIC RESOURCE CORP.
(the "Corporation")

1. Role and Objective

The Audit Committee (the "**Committee**") is a committee of the Board of Directors of the Corporation to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Director approval, the audited financial reports and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to the Corporation and its subsidiaries, are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial reports of the Corporation and related matters.
- Provide an open avenue of communication among the Corporation's auditors, financial and senior management and the Board of Directors.
- To ensure the external auditors' independence and review and appraise their performance.
- To increase the credibility and objectivity of financial reports.
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

2. Composition

The Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of National Instrument 52-110 *Audit Committees*) unless the Board determines to rely on an exemption in NI 52-110. "Independent" generally means free from any business or other direct or indirect material relationship with the Corporation that could, in the view of the Board, reasonably interfere with the exercise of the member's independent judgment.

The Secretary to the Board shall act as Secretary of the Committee.

A quorum shall be a majority of the members of the Committee.

All of the members must be financially literate within the meaning of NI 52-110 unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. Meetings

The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair. As part of its job to foster open communication, the Committee will meet at least annually with management and the external auditors in separate sessions.

Agendas, with input from management, shall be circulated to Committee members and relevant management personnel along with background information on a timely basis prior to the Committee meetings.

The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to the Committee members with copies to the Board of Directors, the Chief Financial Officer or such other officer acting in that capacity, and the external auditor.

The Chief Executive Officer and the Chief Financial Officer or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

The Controller, Treasurer and/or such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

4. Mandate and Responsibilities

To fulfill its responsibilities and duties, the Committee shall:

1) undertake annually a review of this mandate and make recommendations to the Corporate Governance and Compensation Committee as to proposed changes;

2) satisfy itself on behalf of the Board with respect to the Corporation's internal control systems, including, where applicable, relating to derivative instruments:

   (a) identifying, monitoring and mitigating business risks; and

   (b) ensuring compliance with legal and regulatory requirements;

3) review the Corporation's financial reports, MD&A, any annual earnings, interim earnings and press releases before the Corporation publicly discloses this information and any reports or other financial information (including quarterly financial reports), which are submitted to any governmental body, or to the public, including any certification, report, opinion, or review rendered by the external auditors; the process should include but not be limited to:

   (a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial reports;

(b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

(c) reviewing accounting treatment of unusual or non-recurring transactions;

(d) ascertaining compliance with covenants under loan agreements;

(e) reviewing financial reporting relating to asset retirement obligations;

(f) reviewing disclosure requirements for commitments and contingencies;

(g) reviewing adjustments raised by the external auditors, whether or not included in the financial reports;

(h) reviewing unresolved differences between management and the external auditors;

(i) obtain explanations of significant variances with comparative reporting periods; and

(j) determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed;

4) review the financial reports and related information included in prospectuses, management discussion and analysis (MD&A), information circular-proxy statements and annual information forms (AIF), prior to Board approval;

5) with respect to the appointment of external auditors by the Board:

(a) require the external auditors to report directly to the Committee;

(b) review annually the performance of the external auditors who shall be ultimately accountable to the Board of Directors and the Committee as representatives of the shareholders of the Corporation;

(c) obtain annually, a formal written statement of external auditors setting forth all relationships between the external auditors and the Corporation and confirming their independence from the Corporation;

(d) review and discuss with the external auditors any disclosed relationships or services that may impact the objectivity and independence of the external auditors;

(e) be directly responsible for overseeing the work of the external auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting;

(f) review management's recommendation for the appointment of external auditors and recommend to the Board appointment of external auditors and the compensation of the external auditors;

(g) review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;

(h) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

(i) take, or recommend that the full Board of Directors take, appropriate action to oversee the independence of the external auditors;

(j) at each meeting, consult with the external auditors, without the presence of management, about the quality of the Corporation's accounting principles, internal controls and the completeness and accuracy of the Corporation's financial reports;

6) review all public disclosure containing audited or unaudited financial information before release;

7) review financial reporting relating to risk exposure;

8) satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information from the Corporation's financial reports and periodically assess the adequacy of those procedures;

9) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

10) review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial reports of the Corporation and its subsidiaries;

11) review and pre-approve all audit and audit-related services and the fees and other compensation related thereto, and any non-audit services, provided by the Corporation's external auditors and consider the impact on the independence of the auditors; The pre-approval requirement is waived with respect to the provision of non-audit services if:

(a) the aggregate amount of all such non-audit services provided to the Corporation constitutes not more than five percent (5%) of the total amount of revenues paid by the Corporation to its external auditors during the fiscal year in which the non-audit services are provided;

(b) such services were not recognized by the Corporation at the time of the engagement to be non-audit services; and

(c) such services are promptly brought to the attention of the Committee by the Corporation and approved prior to the completion of the audit by the Committee or by one or more members of the Committee who are members of the Board of Directors to whom authority to grant such approvals has been delegated by the Committee;

provided the pre-approval of the non-audit services is presented to the Committee's first scheduled meeting following such approval, such authority may be delegated by the Committee to one or more independent members of the Committee;

12) review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it;

13) with respect to the financial reporting process:

(a) in consultation with the external auditors, review with management the integrity of the Corporation's financial reporting process, both internal and external;

(b) consider the external auditors' judgments about the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting;

(c) consider and approve, if appropriate, changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors and management;

(d) review significant judgments made by management in the preparation of the financial reports and the view of the external auditors as to appropriateness of such judgments;

(e) following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information;

(f) review any significant disagreement among management and the external auditors regarding financial reporting;

(g) review with the external auditors and management the extent to which changes and improvements in financial or accounting practices have been implemented;

(h) review the certification process;

(i) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(j) establish procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

5. Authority

Following each meeting, in addition to a verbal report, the Committee will report to the Board by way of providing copies of the minutes of such Committee meeting at the next Board meeting after a meeting is held (these may still be in draft form).

Supporting schedules and information reviewed by the Committee shall be available for examination by any director.

The Committee shall have the authority to investigate any financial activity of the Corporation and to communicate directly with the internal and external auditors. All employees are to cooperate as requested by the Committee.

The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice to assist in fulfilling its duties and responsibilities at the expense of the Corporation.

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