

TRANS-ORIENT PETROLEUM LTD.

**RESOURCE ESTIMATION AND
ECONOMIC EVALUATION
EAST COAST BASIN, NEW ZEALAND**

September 2008





October 10, 2008

Trans-Orient Petroleum Ltd.
Corporate Head Office
999 Canada Place, Suite 404
World Trade Center
Vancouver, British Columbia
V6C 3E2

Attention: Mr. Drew Cadenhead

**RE: Trans-Orient Petroleum Ltd.
Resource Estimation and Economic Evaluation**

At your request and authorization, AJM Petroleum Consultants ("AJM") has prepared an independent evaluation of the resource potential of the East Coast Basin property in New Zealand, for Trans-Orient Petroleum Ltd. ("Trans-Orient"). The effective date of the evaluation is September 1, 2008.

The evaluation includes an estimate of the total resource potential and Trans-Orient's share of the original volume-in-place in the area. The resource potential was determined in accordance with the business practices, evaluation procedures, and resource definitions contained within National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" (NI 51-101) Section 5.9 and outlined more specifically in the "Canadian Oil and Gas Evaluation Handbook" (COGEH).

This report has been prepared for the exclusive use of Trans-Orient Petroleum Ltd. No part of this report shall be reproduced, distributed, or made available to any other person, company, regulatory body, or organization pursuant to Part 5 Section 5.7 of NI 51-101. AJM Petroleum Consultants hereby gives its consent to the use of its name and to the said estimates pursuant to Part 5 Section 5.7 Item (2) of NI 51-101.

The extent and character of ownership and all factual data supplied by Trans-Orient Petroleum Ltd. were accepted as presented. A field inspection and environmental / safety assessment of the property was not made by AJM and the consultant makes no representation and accepts no responsibilities in this regard.

AJM reserves the right to review all calculations referred to or included in this report and to review the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.



Trans-Orient Petroleum Ltd.
Resource Estimation and Economic Evaluation

A Boe conversion ratio of 6 Mcf: 1 barrel has been used within this report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It has been a pleasure to perform this evaluation for you, and we trust it is sufficient to meet your current requirements. Should you have any questions please do not hesitate to contact the undersigned at (403) 648-3223.

Yours truly,

AJM Petroleum Consultants

Original signed by; "Robin G. Bertram"

Vice President

/ct



Independent Petroleum Consultants Consent

The undersigned firm of Independent Qualified Reserves Evaluators and Auditors of Calgary, Alberta, Canada has prepared an independent evaluation of the resource potential derived therefrom, of the Petroleum and Natural Gas assets of the interests of Trans-Orient Petroleum Ltd. according to the Canadian Oil and Gas Evaluation Handbook. These resources and net present value were estimated using forecast prices and costs (before and after income taxes) according to the requirements of National Instrument 51-101 (NI 51-101). The effective date of this evaluation is August 31, 2008.

In the course of the evaluation, Trans-Orient Petroleum Ltd. provided AJM Petroleum Consultants personnel with basic information which included land, well and accounting (product prices and operating costs) information; reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from AJM Petroleum Consultants non confidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted.

A "Representation Letter" dated October 8, 2008 and signed by both the President & Chief Executive Officer and the Chief Operating Officer was received from Trans-Orient Petroleum Ltd. prior to the finalization of this report. This letter specifically addressed the accuracy, completeness and materiality of all the data and information that was supplied to us during the course of our evaluation of Trans-Orient Petroleum Ltd.'s resources and net present values. This letter is included within.

A field inspection and environmental/safety assessment of the properties was beyond the scope of the engagement of AJM Petroleum Consultants and none was carried out. The "Representation Letter" received from Trans-Orient Petroleum Ltd. provided assurance that no additional information necessary for the completion of our assignment would have been obtained by a field inspection.

The accuracy of any resource and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resource and production estimates presented herein are considered reasonable, and adhere to the COGE Handbook and NI 51-101 (as applicable), the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, current exchange rates, inflation, market demand and government policy which are subject to uncertainties and may in future differ materially from the forecasts herein. Present values of future net revenues documented in this report do not necessarily represent the fair market value of the resources evaluated herein.

Body copy.

Second page format only – use for separate documents that need to be merged with others. You can insert Page / Section breaks where needed.

PERMIT TO PRACTICE

AJM Petroleum Consultants
Permit Number: P-7149

The Association of Professional Engineers,
Geologists and Geophysicists of Alberta



CERTIFICATE OF QUALIFICATION

I, R. G. Bertram, a Professional Engineer, of the 6th Floor, 425 – 1st Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am an associate of AJM Petroleum Consultants, which company did prepare a detailed analysis of certain New Zealand oil and gas assets of the interests of Trans-Orient Petroleum Ltd. The effective date of this evaluation is September 1, 2008.
2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Trans-Orient Petroleum Ltd.
3. I attended the University of Alberta and graduated with a Bachelor of Science Degree in Petroleum Engineering in 1985; that I am a Registered Professional Engineer in the Province of Alberta; and I have in excess of twenty three years of experience in petroleum engineering.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "R. G. Bertram"

R. G. Bertram, P. Eng.

October 9, 2008

Date



CERTIFICATE OF QUALIFICATION

I, L. D. Boyd, a Registered Professional Geologist, of the 6th Floor, 425 – 1st Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am an associate of AJM Petroleum Consultants, which company did prepare a detailed analysis of certain New Zealand oil and gas assets of the interests of Trans-Orient Petroleum Ltd. The effective date of this evaluation is September 1, 2008.
2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Trans-Orient Petroleum Ltd.
3. I attended the University of Calgary and graduated with a Bachelor of Science Degree in Geology in 1976; that I am a Registered Professional Geologist in the Province of Alberta; and I have in excess of thirty two years experience in geological evaluations.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "L. D. Boyd"

L. D. Boyd, P. Geol.

October 9, 2008

Date



October 8, 2008

AJM Petroleum Consultants
1400, 734 – 7th Avenue SW
Calgary, Alberta T2P 3P8


**Re: Standard Representation Letter
Corporate Resource Evaluation**

Regarding the evaluation of our Company's oil and gas resources and independent appraisal of the economic value of these resources for the year ended September 1, 2008 (the "effective date"), we herein confirm to the best of our knowledge and belief as of the effective date of the resources evaluation, the following representations and information made to you during the course and conduct of the evaluation.

1. We (the "Client") have made available to you (the "Evaluator") certain records, information and data relating to the evaluated properties that we confirm is, with the exception of immaterial items, complete and accurate as of the effective date of the resources evaluation including the following:
 - a. accounting, financial and contractual data;
 - b. asset ownership and related encumbrance information;
 - c. details concerning product marketing, transportation and processing arrangement;
 - d. all technical information including geological, engineering and production and test data;
 - e. estimates of future abandonment and reclamation costs.
2. We confirm that all financial and accounting information provided to you is, to the best of our knowledge, both on an individual entity basis and in total, entirely consistent with that reported by our Company for public disclosure and annual audit purposes.
3. We confirm that our Company has satisfactory title to all of the assets, whether tangible, intangible or otherwise, for which accurate and current ownership information has been provided.
4. With respect to all information provided to you regarding product marketing, transportation and processing arrangements, we confirm that we have disclosed to you all anticipated changes, terminations and additions to these arrangements that could reasonably be expected to have a material impact on the evaluation of our Company's resources and future net revenues.
5. With the possible exception of items of an immaterial nature, we confirm as of the effective date of the evaluation that:
 - For all operated properties that you have evaluated, no changes have occurred or are reasonably expected to occur to the operating conditions or methods that have been used by our Company over the past twelve (12) months, except as disclosed to you. In the case of non-operated properties, we have advised you of any changes of which we have been made aware.

- This letter provides assurance that no additional information necessary for the completion of your assignment would have been obtained by a field inspection.
- All regulatory approvals, permits and licenses required to allow continuity of future operations and production from the evaluated properties are in place and, except as disclosed to you, there are no directives, orders, penalties or regulatory rulings in effect or expected to come into effect relating to the evaluated properties.
- Except as disclosed to you, the producing trend and status of each evaluated well or entity in effect throughout the three month period preceding the effective date of the evaluation are consistent with those that existed for the same well or entity immediately prior to this period.
- Except as disclosed to you, we have no plans or intentions related to the ownership, development or operation of the evaluated properties that could reasonably be expected to materially affect the production levels or recovery of resources from the evaluated properties.
- If material changes of an adverse nature occur in the Company's operating performance subsequent to the effective date and prior to the report date, we will undertake to inform you of such material changes prior to requesting your approval for any public disclosure of resources information.
- Between the effective date of the report and the date of this letter, nothing has come to our attention that has materially affected or could materially affect our resources and the economic value of these resources that has not been disclosed to you.

Yours truly,



President & Chief Executive Officer



Chief Operating Officer

EVALUATION PROCEDURE

Effective as of September 2008



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INTRODUCTION – RESERVES METHODOLOGY

Reference Volume 1 of the Canadian Oil and Gas Evaluation Handbook (COGEH)

Reserves Evaluation

A “Reserves Evaluation” is the process whereby a qualified reserves evaluator estimates the quantities and values of oil and gas reserves by interpreting and assessing all available pertinent data. The value of an oil and gas asset is a function of the ability or potential ability of that asset to generate future net revenue, and it is measured using a set of forward-looking assumptions regarding reserves, production, prices, and costs. Evaluations of oil and gas assets, in particular reserves, include a discounted cash flow analysis of estimated future net revenue.

Reserves Audit

A “Reserves Audit” is the process carried out by a qualified reserves auditor that results in a reasonable assurance, in the form of an opinion, that the reserves information has in all material respects been determined and presented according to the principles and definitions adopted by CIM (Petroleum Society), SPEE (Calgary Chapter), and APEGGA and are, therefore free of material misstatement.

The reserves evaluations prepared by the Corporation have been audited, not for the purpose of verifying exactness, but the reserves information, company policies, procedures, and methods used in estimating the reserves will be examined in sufficient detail so that AJM Petroleum Consultants (“AJM”) can express an opinion as to whether, in the aggregate, the reserves information presented by the Corporation are reasonable.

AJM may require its own independent evaluation of the reserves information for a small number of properties, or for a large number of properties as tests for the reasonableness of the Corporation’s evaluations. The tests to be applied to the Corporation’s evaluations insofar as their methods and controls and the properties selected to be re-evaluated will be determined by AJM, in its sole judgment, to arrive at an opinion as to the reasonableness of the Corporation’s evaluations.



Reserves Review

A “Reserves Review” is the process whereby a reserves auditor conducts a high-level assessment of reserves information to determine if it is plausible. The steps consist primarily of enquiry, analytical procedure, analysis, review of historical reserves performance, and discussion with the Corporation’s reserves management staff.

“Plausible” means the reserves data appear to be worthy of belief based on the information obtained by the independent qualified reserves auditor in carrying out the aforementioned steps. Negative assurance can be given by the independent reserves auditor, but an opinion cannot. For example, “Nothing came to my attention that would indicate the reserves information has not been prepared and presented in accordance with principles and definitions adopted by the Canadian Institute of Mining, Metallurgy & Petroleum (CIM) (Petroleum Society), the Society of Petroleum Evaluation Engineers (SPEE) (Calgary Chapter), and APEGGA (Practice Standard for the Evaluation of Oil and Gas Reserves for Public Disclosure).

Reviews do not require examination of the detailed document that supports the reserves information, unless this information does not appear to be plausible.

GEOLOGY

An initial review of each property was undertaken to establish the produced maturity of the reservoir being evaluated. Where there existed extensive production history a geologic analysis was not conducted since the remaining hydrocarbons could be determined by productivity analysis.

For properties that were not of a mature productivity nature a geologic review was conducted. This work consisted of analysis of logs in the area of interest and review of well tests. Net formation thickness (pay), porosity, and initial water saturation were then utilized to establish volumetric hydrocarbons in place.

LAND SCHEDULE AND MAPS

The evaluated Corporation provided schedules of land ownership which included lessor and lessee royalty burdens. The land data was accepted as factual and no investigation of title by AJM was made to verify the records.

Evaluated well maps included within this report represent all of the Corporation's interests that were evaluated in the specified area.



RESERVE ESTIMATION AND PRODUCTION FORECASTS

Reserves were estimated either by i) volumetric, ii) decline curve analysis, iii) material balance techniques, or iv) performance predictions.

Volumetric reserves were estimated using the wellbore net pay and an assigned drainage area or, where sufficient data was available, the reservoir volumes calculated from isopach maps. Reservoir rock and fluid data were obtained from available core analysis, well logs, PVT data, gas analysis, government sources, and other published information either on the evaluated pool or from a similar reservoir in the immediate area. In mature (producing) reservoirs decline curve analysis and/or material balance was utilized in all applicable evaluations.

Whenever there is the need within an evaluation to assign reserves based on analogy or when volumetric reserves are being assigned, petroCUBE™ is used by AJM evaluators.

petroCUBE is a web-based (www.petroCUBE.com) product co-developed by AJM Petroleum Consultants and geoLOGIC Systems Inc. petroCUBE provides geostatistical, technical and financial information for conventional hydrocarbon plays throughout the Western Canadian Sedimentary Basin ("WCSB").

The information provided by petroCUBE is an unbiased independent perspective into the historical performance of the conventional hydrocarbon activity in the WCSB. The statistical information is presented by commodity type (gas, oil) with each commodity further analyzed by geographic area and play type.

Gas is divided into 16 geographic areas and approximately 14 stratigraphic groupings comprising over 120 gas plays; Oil is divided into 13 geographic areas and approximately 14 stratigraphic groupings comprising over 75 oil plays. Analysis of each play is formulated on a per-well zone basis, based on the statistics and full cycle economics of wells drilled in the recent past (last five years).



Analysis output includes cumulative frequency resource distribution curves, chance of success tables, production performance profiles for each play type and area, unrisks and risks resources, and initial production rates on a per well zone basis, and full cycle economic and play parameters.

Cumulative frequency curves show how the reserves for a play are distributed. These calculations include the average reserves for a play (P_{mean}), reserves for the best 10 percent of the wells (P_{10}), the minimum reserves developed by 90 percent of the wells (P_{90}).

Reserves assigned are compared to those reserves noted in the cumulative frequency curves for the corresponding area and play type. Typically an expected or proved plus probable reserve is a P_{mean} reserve.

Production forecasts were based on historical trends or by comparison with other wells in the immediate area producing from similar reservoirs. Non-producing gas reserves were forecast to come on-stream February 1, 2010 under direct sales pricing and deliverability assumptions, if a tie-in point to an existing gathering system was in close proximity (approximately two miles). If the tie-in point was of a greater distance (and dependent on the reserve volume and risk) the reserves were forecast to come on-stream February 1, 2011. If the reserves were located in a remote location and/or the reserve volume was of higher risk, the reserves were forecast to come on-stream no earlier than February 1, 2014. These on-stream dates were used when the company could not provide specific on-stream date information.



RESOURCE AND RESERVE DEFINITIONS

Resource Classification: Resources are classified by AJM Petroleum Consultants in accordance with the definitions published by the Petroleum Society of CIM in The Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1 2nd Edition. The reader is referred to the Handbook for a complete description of Resources and only the particular definitions are quoted as follows.

The term “resources” encompasses all petroleum quantities that originally existed on or within the earth’s crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, total resources is equivalent to Total Petroleum Initially-In-Place (PIIP).

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

Discovered Petroleum Initially-In-Place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Petroleum Initially-In-Place includes Production, Reserves, and Contingent Resources; the remainder is unrecoverable.

Production is the cumulative quantity of petroleum that has been recovered at a given date.

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. Reserves are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on development and production status. Refer to the full definitions on Reserves in Section 5.4 of COGEH.

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 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. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Refer to COGEH and Figure 5-1.

Unrecoverable is that portion of Discovered and Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of Undiscovered Petroleum Initially-In-Place is referred to as Prospective Resources; the remainder as Unrecoverable.

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. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Refer to COGEH and Figure 5-1.

Reserves, Contingent Resources, and Prospective Resources should not be combined without recognition of the significant differences in criteria associated with their classification. For example, the sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as Remaining Recoverable Resources. When resources categories are combined, it is important that each component of the summation also be



provided, and it should be made clear whether and how the components in the summation were adjusted for risk.

Reserve Classification: Reserves are classified by AJM in accordance with the following definitions published by COGEH and which meet the standards established by National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities and found in Appendix 1 to Companion Policy 51-101 CP, Part 2 Definition of Reserves.

Reserve Categories

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- 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:

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.

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.

Possible Reserves are 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.

Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

Developed Reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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 category (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 subdivide 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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest – level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

ROYALTIES AND TAXES

General

All royalties and taxes, including the lessor and overriding royalties, are based on current government regulations, leases or farmout agreements.

Lessor interests and burdens applicable to each entity are detailed in the Well Interests Table.

AJM Petroleum Consultants utilize reserves and valuation program Mosaic (Version 2.5), a software product of Entero Corporation.



OPERATING AND CAPITAL CONSIDERATIONS

Operating and capital costs were based on current costs escalated to the date the cost was incurred. Costs listed on the Capital Sheet and Economic Parameter Sheet are in current year dollars. The economic runs provide the escalated dollar costs as found in the Pricing Table 1 in the Price and Market Demand section.

Reserves estimated to meet the standards of NI51-101 of constant prices and costs, are based on unescalated operating and capital costs.

Capital costs were either provided by the Corporation (and reviewed by AJM for reasonableness); or determined by AJM taking into account well capability, facility requirement, and distance to markets. Facility expenditures for shut-in gas are forecast to occur in the month prior to the wells first production.

Operating costs were determined from historical data on the property as provided by the evaluated Corporation. If this data was not available or incomplete, the costs were based on AJM experience and historical database. Operating costs are defined into three types.

The first type, variable (\$/Unit), covers the costs directly associated with the product production. Costs for processing, gathering and compression are based on raw gas volumes. Over the life of the project the costs are inflated in escalated runs to reflect the increase in costs over time. In a constant dollar review the costs remain flat over the project life.

The second type, fixed plant or battery (\$/year), is again a fixed component over the project life and reflects any gas plant or battery operating costs allocated back to the evaluated group. The plant or battery can also be run as a separate group and subsequently consolidated at the property level. It must be noted that discussion with the client is required to determine operational feasibility of the facility over time. Parts of the plant may be shut-in as capacity is reduced over time. At some future point in time capital may be required to optimize the facility or take the product to a different facility paying a trucking cost for oil and gathering and processing fee for gas. Potential availability and location of plants with excess capacity has to be considered. As per previous operating costs, this cost is also inflated over time in escalated cases and held constant in constant dollar runs.



The third type takes the remaining costs that are not associated with the first two and assigns them to the well based on a fixed and variable component. A split of 65 percent fixed and 35 percent variable assumes efficiencies of operation over time, i.e.: the well operator can reduce the number of monthly visits as the well matures, workovers may be delayed, well maintenance can also be reduced. The basic assumption is that the field operator will continue to find efficiencies to reduce the costs over time to maintain the overall \$/Boe cost. Thus as the production drops over time the 35 percent variable cost will account for these efficiencies. If production is flat all the costs will also remain flat. Both the fixed and variable costs in this type are inflated in the escalated case and held constant in the constant dollar review. These costs also include property taxes, lease rentals, government fees, and administrative overhead.

In evaluations conducted for purposes of NI51-101, well abandonment costs have been included and these costs were either provided by the Corporation (and reviewed by AJM for reasonableness) or estimated by AJM based on its experience. For undeveloped reserve estimates for undrilled locations, site reclamation costs are also included for the purpose of determining whether reserves should be attributed to that property in the first year in which the reserves are considered for attribution to the property.

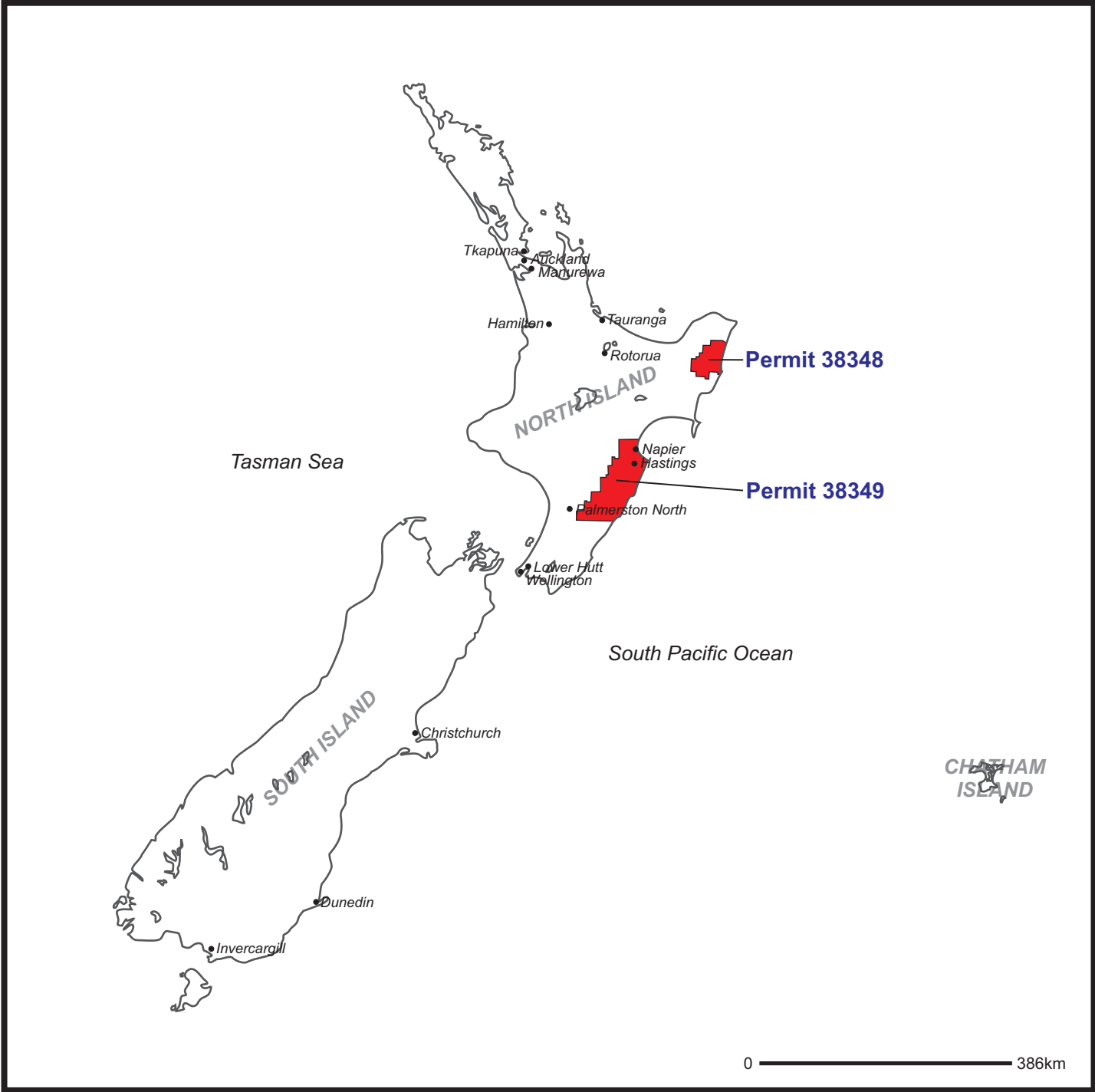



GLOSSARY OF TERMS

This glossary is provided only for convenience. AJM subscribes to the Glossary of Terms as defined by the Canadian Oil and Gas Evaluation Handbook. The COGE Handbook can be obtained from the Petroleum Society of CIM at www.petsoc.org.

Gross Reserves	These are the total reserves to be recovered from a property.
Company Gross Reserves	These are the working interest owner's share of gross reserves before the deduction of royalties. Royalty interest share of reserves is not included in this category.
Company Net Reserves	These are the working interest owner's share of gross reserves after the deduction of royalties. Royalty interest share of reserves is included in this category.
Net Profits Interests	Occasionally, interests in oil and gas properties are encumbered by net profits interests, in addition to lessor and overriding royalty interests. A net profits interest is an interest in production income only and not in production. The net profits interest owner may have value, but has not interest in reserves; therefore, no reserves are assigned to this owner.
Net Operating Income	Company interest income after the sale of oil, gas, by-products plus other income, less burdens and operating expenses.
Before Tax Cash Flow	Net operating income less any capital investment to the property
Discounting	Discounting utilized by AJM Petroleum Consultants being the projections of values discounted to the middle of a given period utilizing the following formula: Discount Factor: $\frac{1}{(1 + i)^{n-1/2}}$ where i = interest rate as a decimal per period and n = number of periods.

Crude Oil	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 non-hydrocarbon compounds, but does not include liquids obtained from the processing of natural gas.
Synthetic Crude Oil	A mixture of hydrocarbons derived by upgrading crude bitumen from oil sands, and kerogen from oil shales or other substances such as coal. May contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil.
Raw Natural Gas	Natural gas as it is produced from the reservoir prior to processing. It is gaseous at the conditions under which its volume is measured or estimated.
Marketable Natural Gas (Sales Gas)	Natural gas that meets specifications for its end use, whether it occurs naturally or results from the processing of raw natural gas. Field and plant fuel and losses are excluded, excepting those related to downstream reprocessing plants.
Natural Gas Liquids	Those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.
Expenses Fixed	Expenses that do not vary with fluctuations in the producing rate.
Expenses Variable	Expenses that vary with fluctuations in the producing rate.



	
<p>Trans-Orient Petroleum Ltd. Property Location Map Effective September 1, 2008</p>	
PROJECT: tra loc	DATE: 2008/10/09

PROPERTY INDEX

1. East Coast Basin, New Zealand

TRANS-ORIENT PETROLEUM LTD.

EAST COAST BASIN, NEW ZEALAND

Effective Date: September 1, 2008

Prepared by:

R. G. Bertram, P. Eng.

L. D. Boyd, P. Geol.



EAST COAST BASIN, NEW ZEALAND

Trans-Orient Petroleum Ltd.'s ("Trans-Orient") East Coast Basin property is on the east coast of New Zealand's North Island in the vicinity of Napier. The company holds a 100 percent working interest in two onshore petroleum exploration permits ("PEPs") that target the East Coast Fold Belt. PEP 38348 is located north of Napier and Hawke Bay and covers 530, 535 acres. PEP 38349 covers 1,633,651 acres and is to the south of Napier. The company committed to an initial work program consisting of geological and geophysical studies along with the acquisition, processing, and interpretation of 50 kilometers (20 kilometers in PEP 38348, 30 km in PEP 38349) of seismic prior to November 2008. Prior to November 8, 2009, the company is required to drill two exploratory wells (one on each permit). Royalties paid to the New Zealand government (the 'Crown') for discoveries found before December 31, 2009 consist of an Ad Valorem royalty of one percent on natural gas and five percent on oil plus an Accounting Profits royalty of 15 percent on the first \$NZ 250 million of gross sales reverting to a 20 percent royalty thereafter. Discoveries made after December 31, 2009 are subject to a five percent Ad Valorem royalty plus a 20 percent Accounting Profits Royalty.

This report summarizes the company's unconventional Paleocene resources within the Whangai Shale and Waipawa Black Shale. Although the company has not drilled any wells to test the Paleocene shales, several wells have penetrated the shale zones in the past. These wells include the Rere 1 well in the northern PEP 38348 permit, Opoutama 1 in PEP 38346, and Hukarere-1 which was drilled offshore in PEP 38344.

The Opoutama 1 well was drilled in 1967 and encountered 734 meters of Whangai shale at 1,469 meters. This well's total depth was 3,657 meters. Rere-1 was drilled to a total depth of 4,351 meters in 1985. The well encountered 392 meters of Whangai zone at 1,990 meters. The Hukarere-1 well was drilled in 2001 in Hawke Bay to a total depth of 3,230 meters. This well also encountered 323 meters of the Whangai shale beginning at 2,764 meters.

GEOLOGY

New Zealand's East Coast Basin extends over 40,000 Km² of the North Island. It is characterized by a Late Cretaceous to Oligocene passive margin section overlain by a very thick Miocene-Pliocene active margin sequence. The whole sequence was deposited in marine conditions, with non-marine deposits



and especially coal very limited in areal extent and thickness, and present as remnants only near the western margin of the Basin. Deep water deposits including clay rich shales and turbidite sandstones predominate in the thick Mid to Upper Cretaceous and Eocene sequences.

The East Coast of New Zealand is a highly structured complex basin with structures clearly visible in outcrop and on seismic. In the southern and central part the dominant structural trend is north-northeast to south-southwest to northeast to southwest, with most prospective structures generated by southeast to east-southeast verging reverse faults. Many of these faults have a dextral wrench component. In the North part of the basin the structural trends are more variable with a series of major normal faults generally downthrown to the east or southeast.

Oil seeps are present throughout the basin from South to North on both of Trans-Orient's permits. Biomarker and isotope studies indicate that the main oil-prone source rocks are the deep marine shales of the Whangai and Waipawa Black Shale. (Francis, Bennett, Courteney, 2004)

RESOURCES ASSESMENT

Prospective resources have been assigned to the two permits based upon a review of the well log data and core pyrolysis results provided by the company. Where possible, AJM reviewed the methods by which the company estimated the in place resource volumes. In cases where a range of parameters was provided, the lower values were taken to be the minimum (P_{99}), and the high values were taken to be the maximum (P_1). Original in-place resources were determined by probabilistic calculations.

Probabilistic volumes were determined for each of three cases: low estimate (P_{90}), best estimate (P_{50}) and high estimate (P_{10}). These estimates utilized the low, best, and high estimates for reservoir parameters such as overall pay, areal extent, and results from source rock pyrolysis testing. Estimates of areal extent were based upon the regional mapping and outcrop information provided by the company. The minimum area estimate was determined by assigning a one township areal, while the maximum area estimate was based upon a moderate percentage of the total combined permit area. The determination of the low, best, and high hydrocarbon in place estimates include consideration for the range of reported S_1 (free hydrocarbons in the source rock) and S_2 (hydrocarbons available through hydro-cracking or diagenesis) values. The products of these calculations were plotted on a probability scale so that the correct low (P_{90}) and high (P_{10}) hydrocarbon in place volumes could be interpolated.

The best estimate (P_{50}) hydrocarbon in place volume of 12.6 billion barrels is the total available volume (S_1 plus S_2) for both the Waipawa and Whangai shales. A summary of the prospective resources for both permits is included in Appendix A.

DEVELOPMENT FACTORS

The Waipawa and Whangai shales represent an unconventional development similar to that of the Bakken Formation within the Willesden Basin in southern Saskatchewan and North Dakota. The area has several oil and natural gas seeps that clearly indicate the area is prospective for hydrocarbons. Prior to any defined development, additional drilling, sampling and testing will be required to further quantify the hydrocarbon potential in the area.

The company has plans to drill an exploratory well on each of the permits. The cost of the each well is estimated to be \$CDN 1,500,000. This capital will allow for the drilling of a 1,500 m vertical test that will recover significant core. In addition, each well will have a modern well log suite run to allow for the optimal review and characterization of the shale zones. As per the exploration permit requirements, these wells should be drilled and tested by the end of the third quarter of 2009.

AJM's long term forecast for light oil is \$US 100.00/bb WTI. New Zealand has an active market for petroleum products, and the exploration permits are close to a major ocean port in Napier. As a result, it is expected that any future development in the area will have access to markets and transportation infrastructure.

RISK FACTORS

The major risk factors for this development are strictly geological. New Zealand has a strong and stable democratic government and has a positive business environment, and as noted above, the development will have ready access to both markets and transportation infrastructure. The geological risks include the possibility that the free hydrocarbons available within the matrix of the shale will not readily flow in commercial quantities. In addition, the overall areal extent and thickness of the shale zones will need to be verified as only a small number of wells have penetrated the zones of interest.



Trans-Orient Petroleum Ltd.
East Coast Basin - PEP 38348 & 38349

Prospective Hydrocarbon-In-Place Resource Estimate - Free Hydrocarbons (S₁)

Waipawa Black Shale

		Low Estimate	Best Estimate	High Estimate	Swanson's Mean
Area	(acres)	58,575	187,470	600,000	272,560
Thickness	(feet)	50.0	81.2	132.0	87.1
Thickness	(metres)	15.2	24.8	40.2	26.5
Pyrolysis S ₁	(kg/tonne)	3.41	5.00	7.33	5.22
Recovery Factor	(fraction)	0.01	0.02	0.05	0.03
Original HC-In-Place	(Mstb)	536,555	1,736,072	5,617,220	2,540,561
Recoverable HC-In-Place	(Mstb)	9,386	38,820	160,561	66,512

Whangai Shale

		Low Estimate	Best Estimate	High Estimate	Swanson's Mean
Area	(acres)	58,575	187,470	600,000	272,560
Thickness	(feet)	1,150.0	1,398.21	1,700.0	1414.3
Thickness	(metres)	350.5	426.18	518.2	431.1
Pyrolysis S ₁	(kg/tonne)	0.2	0.42	0.8	0.46
Recovery Factor	(fraction)	0.01	0.03	0.07	0.03
Original HC-In-Place	(Mstb)	804,200	2,482,187	7,661,349	3,532,540
Recoverable HC-In-Place	(Mstb)	15,204	65,673	283,667	115,930

Total Original HC-In-Place (Mstb) 1,340,754 4,218,259 13,278,569 6,073,101



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East Coast Basin - PEP 38348 & 38349

Prospective Hydrocarbon-In-Place Resource Estimate - Total Potential Hydrocarbons (S₁+S₂)

Waipawa Black Shale

		Low Estimate	Best Estimate	High Estimate	Swanson's Mean
Area	(acres)	58,575	187,470	600,000	272,560
Thickness	(feet)	50.0	81.2	132.0	87.1
Thickness	(metres)	15.2	24.8	40.2	26.5
Pyrolysis S ₁ +S ₂	(kg/tonne)	10.23	15.00	21.99	15.67
Original HC-In-Place	(Mstb)	1,609,665	5,208,216	16,851,659	7,621,684

Whangai Shale


		Low Estimate	Best Estimate	High Estimate	Swanson's Mean
Area	(acres)	58,575	187,470	600,000	272,560
Thickness	(feet)	1,150.0	1398.2	1,700.0	1414.3
Thickness	(metres)	350.5	426.2	518.2	431.1
Pyrolysis S ₁ +S ₂	(kg/tonne)	0.69	1.25	2.25	1.38
Original HC-In-Place	(Mstb)	2,412,599	7,446,562	22,984,048	10,597,619

Total Original HC-In-Place (Mstb) 4,022,263 12,654,778 39,835,707 18,219,302






- Permit 38348 Area
- Well

	
<p>Trans-Orient Petroleum Ltd. Permit 38348, New Zealand Effective September 1, 2008</p>	
PROJECT: 38348	DATE: 2008/10/09



- Permit 38349 Area
- Evaluated Well



Trans-Orient Petroleum Ltd.
Permit 38349, New Zealand
Effective September 1, 2008

PROJECT: 38349	DATE: 2008/10/09
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