MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated November 14, 2013, for the three months ended September 30, 2013 and should be read in conjunction with the Company's accompaning condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2013.

The condensed consolidated interim financial statements for the three months ended September 30, 2013, have been prepared in accordance with IAS, Interim Financial Reporting Standards ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Results for the period ended September 30, 2013, are not necessarily indicative of future results. All figures are expressed in Canadian dollars unless otherwise stated.

ABOUT TAG OIL LTD

TAG Oil Ltd. ("TAG or the Company") is a Canadian registered oil and gas producer and explorer with assets consisting of approximately 2.7 million acres of land onshore in the Taranaki, East Coast and Canterbury Basin's of New Zealand and 30,816 (77,039 gross acres) offshore in the Taranaki Basin as at September 30, 2013. TAG's business plan is designed to grow through increased cash provided by operating activities, strategic acquisitions and continued exploration/development drilling to grow reserves.

Maintaining 100% ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's 100% owned and operated Cheal, Cardiff and Sidewinder oil and gas fields insures the Company can commercialize all discoveries and developments expeditiously, as well as offer third party processing to other companies in the Basin.

The Company's fiscal year 2012 and 2013 shallow drilling program, focused within TAG's 100% owned Cheal and Sidewinder fields, targeted the proven Urenui and Mt. Messenger formations and provides TAG with long-term stable production, predictable decline rates and significantly more subsurface knowledge that is being incorporated into future drilling programs. The resulting cash flow, when combined with a strong balance sheet, has allowed TAG to embark on the most active and diverse exploration program in the Company's history for fiscal 2014.

The fiscal year 2014 drilling program activity is focused substantially within the Company's four new Taranaki Basin permits awarded in the 2012 New Zealand Blocks Offer as well as a deep well (Cardiff-3) currently being drilled within the Cheal mining permit. This program is well underway with significant progress on the consenting, construction and drilling of nine new shallow wells and two deep wells. This is discussed in more detail below.

The Company remains in a strong financial position, with sufficient working capital to fund operations and meet all commitments for the foreseeable future.

FINANCIAL AND OPERATING HIGHLIGHTS

- At September 30, 2013, the Company had cash of $61.4 million, working capital of $62.9 million and no debt.
- Capital expenditures made on oil and gas assets and Opunake Hydro Limited ("OHL") in the first six months of fiscal year 2014 were $26.6 million compared to $33.3 million for the same period last year.
- Average daily production increased by 25% to 2,227 BOE's per day in the first six months of fiscal year 2014 compared to 1,784 BOE's per day the same period last year. Average daily production increased by 14% to 2,100 BOE's per day in the quarter ending September 30, 2013 compared to the same period last year.
- Revenue in the six months of fiscal year 2014 was $30.6 million representing a 43% increase over the same period last year.
- Cash provided by operating activities for the six months ending September 30, 2013, prior to non-cash working capital adjustments, was $17 million compared to $11.85 million last year. After non-cash adjustments, operating activities provided $14.2 million in cash for the six months to September 30, 2013 compared to $15.0 million in the same period last year.
- The Company concluded a bought deal offering consisting of 5,700,000 common shares of the Company at a price of $4.40 per Common Share for aggregate gross proceeds of $25,080,000. The Company has also granted the Underwriters an option to purchase, on the same terms as the Offering, up to an additional 855,000 Common Shares at a price of $4.40 per Common Share for

TAG Oil Ltd.
www.tagoil.com

Corporate Office
885 West Georgia Street
Suite 2040
Vancouver, BC
Canada V6C 2G2
ph 604-682-6496
fx 604-682-1174

Technical Office
P.O. Box 402
New Plymouth, 4340
New Zealand
ph 64-6-759-4019
fx 64-6-759-4065

additional gross proceeds of $3,762,000. The Over-Allotment Option is exercisable in whole or in part at any time prior to 30 days after the Closing Date.

- The Company, commencing December 1, 2013, appointed Mr. Chris Ferguson as its Chief Financial Officer ("CFO"), replacing Mr. Blair Johnson.

- The Company is drilling the deep gas/condensate prospect, Cardiff-3 which is currently drilling ahead to its total depth targeted at 4,900 meters with testing expected in November/Decmber followed by fracking operations expected to take place in January of 2014. All required consents have been received for operations to be conducted.

- The Company has drilled three shallow wells and has spudded a fourth well in PEP 54877 with joint venture partner East West Petroleum. Permanent production facilities have been completed to enable testing and production of these wells. At the time of this report the Cheal-E1 and Cheal-E2 wells are on test with strong initial oil flows.

- The Company has signed a new surface access agreement in the East Coast Basin permit for drilling access on PEP 38348.

PROPERTY REVIEW

Taranaki Basin:

PMP 38156 - Cheal Oil and Gas Field (TAG 100%)

At the time of this report, the Cheal field has nineteen shallow wells on full, part-time or constrained production out of a total of twenty wells that are capable of producing. The remaining well is awaiting the installation of new production equipment. The Cheal field produced an average of 1,482 BOE's per day in the quarter ended September 30, 2013, compared to an average of 897 BOE's per day for the same period in fiscal 2013, representing a 67% increase as a result of the completion of the Cheal facilities expansion compared to last year when the facilities were still under construction.

The Cheal wells are providing steady oil production and, as expected, more predictable decline rates. The majority of wells at the Cheal oil and gas field are now on production and utilizing good oil field practice, the Company will continue to optimize production methods and perform planned routine maintenance on a regular basis, which requires certain wells to be shut-in periodically.

The deep well prospect, Cardiff-3, was spudded in September and is currently drilling ahead to its total depth targeted at 4,900 meters. The Company plans to perforate the well and intends to initially production test on an unstimulated natural flow to better understand the reservoir performance. A hydraulic-fracture stimulation will be performed depending on a number of factors such as the unstimulated flow rates, total meters of net gas pay, indicative in situ permeability, and the interpreted volume of original gas in place that could be accessed with this well bore. It is anticipated that in the event of a success at Cardiff-3, a total of three wells would be needed to fully develop the prospective resource estimated at 160 BCF and 5.49 million barrels of condensate on a P50 basis.

The Cardiff-3 well is being drilled from the Cheal-C site, which is connected by a pipeline to the Cheal-A processing facilities which provides open access to the New Zealand gas sales network allowing for fast-track development of the well upon success.

PMP 53803 - Sidewinder Oil and Gas Field (TAG 100%)

At the time of this report, the Sidewinder field has four wells on full, part-time or constrained production out of a total of seven wells that are capable of producing. The remaining three wells are awaiting the installation of production equipment or workovers. The Sidewinder field produced an average of 618 BOE's per day in the quarter ended September 30, 2013, compared to an average of 951 BOE's per day for the same period in fiscal 2013, representing a 34% decrease. The decrease is largely due to the Sidewinder wells coming off their initial flush production and natural decline rates. The Sidewinder-A7 well bore, drilled earlier this year, has been designed to enable the Company to drill the Hellfire deep prospect at a later date.

PEP 38748 (TAG 100%)

The permit work program includes the drilling of two exploration wells prior to August 2014. During the quarter, the Company has been liasing with stakeholders and is negotiating an access agreement for a well-site lease. Resource consent documents are currently being prepared and, once granted, the Company will begin construction of the well-site lease and drilling the wells

PEP 54876, PEP 54877 and PEP 54879 (TAG 50%, 70% and 50% respectively and operator)

As stated above, the Company has embarked on the most diverse and active drilling campaign in its history with drilling and completion operations occuring simultaneously. The drilling efforts and ability to fast-track discoveries into production through the Company's existing 100% owned facilities will enable the Company to add reserves and increase cash flow on success. The shallow exploration wells, targeting the Mt Messanger and Urenui zones, that are discussed in the following permits are expected to show similar characteristics to our existing Cheal shallow wells which have averaged EUR of 300 BOE's per day and provide steady, long-term oil production after the initial flush production.

PEP 54876 – (TAG 50% and operator)

The permit work program includes reprocessing 200 kilometers of 2D seismic and drilling one exploration well, which is to be funded 100% up to $2.5 million by the Company's joint venture partner East West Petroleum Limited ("EWP") with any costs in excess of $2.5 million being shared based on each companies pro-rata interest in the permit. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million of net oil and natural gas revenue before all future revenue is split according to each party's working interest.

During the quarter and to date, the Company has completed reprocessing of seismic data and has incorporated that data into a drill-ready prospect known as Southern Cross. In addition, the Company has been liasing with stakeholders and has signed an access agreement for a well-site lease. Resource consent is currently sought and, once granted, the Company will begin construction of the well-site lease and drill the wells.

PEP 54877 – (TAG 70%)

The permit work program includes the drilling of five exploration wells, two of which have been funded 100% to $5.0 million by the Company's joint venture partner EWP with costs in excess of $5.0 million being shared based on each companies pro-rata interest in the permit. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million per well of net oil and natural gas revenue before all future revenue is split according to each party's working interest.

At the time of this report, the Company has signed two land access agreements, securing two well-site locations, known as Cheal D and Cheal E, to drill up to five commitment wells. Resource consent applications have been granted that allow the Company to drill up to twelve wells on each site. Construction has been completed for the Cheal E site and three of five wells have been drilled and completed. Two of the wells have been drilled, logged and completed as anticipated commercial producers and initial testing has confirmed moveable hydrocarbons to surface. The third well has recently reached TD and has been logged with completion operations currently underway. At the time of this report the fourth well has spudded and is expected to reach total depth in November. Facilities to enable production testing of the wells is complete and initial testing of the wells is underway.

A second site, Cheal D, will be constructed next year in anticipation of further drilling on this permit with Cheal D site also enabling the Company to drill wells within the Companys' Cheal mining permit as well.

PEP 54879 – (TAG 50%)

The permit work program includes drilling three shallow exploration wells, one of which is to be funded to a total of $2.5 million by the Company's joint venture partner EWP. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million net oil and natural gas revenue before all future revenue is split according to each party's working interest.

At the time of this report, the Company has identified a well-site location, known as Cheal-G, and has signed a land access agreement. A resource consent application to drill up to twelve wells has been approved by and construction of the well-site lease is about to commence.

PEP 54873 – (TAG 100%)

The Heatseeker prospect has been identified clearly on 2D seismic and has similar geological features to the adjacent landmark Kapuni gas/condensate discovery field, including apparent 4-way dip closure at the crest of the feature. The permit is located in close proximity of the Kapuni gas / condensate processing facility which could allow for an efficient route to commercialization upon discovery.

During the quarter and to date, the Company has been liasing with stakeholders and has signed an access agreement for a well-site lease. Resource consent to drill the Heatseeker well is currently being processed by the local council and, once granted, the Company will begin construction of the well-site lease in preparation for the drilling of the Heatseeker well, scheduled to follow the Cardiff-3 well in early 2014.

PEP 52181 - Kaheru Offshore (TAG 40%)

Planning work by the Operator, New Zealand Oil and Gas, continues for the Kaheru-1 offshore well. The Kaheru prospect is located in 22 meters of water and is a shallow water extension of the onshore Taranaki production fairway. A large 145 km2 3D seismic survey with several reprocessing volumes covers the entire prospect and allows for four way dip closure imaging. The prospect is offset by prolific oil and gas fields along the entire thrust belt trend. The multi-zone prospect Kaheru has been independently evaluated (on a 100% basis) as having a resource potential of 43 MMbbs oil with 72 BCF of associated gas.

A budget for long lead items and well preparations was approved and the Joint Venture has secured a rig slot in order to drill the Kaheru well at the end of the jack-up rig's existing schedule at the end of calendar 2014 to early 2015.

East Coast Basin:

At September 30, 2013, the Company controls a 100% working interest in three exploration permits totaling 1.42 million acres in the East Coast basin of New Zealand. The Company has acquired proprietary 2D seismic data, completed extensive geological surface and sub-surface studies initially drilled a number of stratigraphic wells within three of the permits.

The Company has added East Coast Basin unconventional drilling to its growth plan with a dedicated effort to unlocking the potential within the Company's 1.42 million acre tight-oil play that compares favourably to commercial tight-oil plays in North America. In April of 2013, the Company drilled and cased its first tight-oil well, Ngapaeruru-1, with promising initial results achieved over a 155 meter gross hydrocarbon column. Additional drilling of at least three wells is expected over the next 12 to 18 months to achieve TAG's goal of converting undiscovered resource potential within the Company's permits to proved reserves. The Company recently announced the addition of two unconventional oil and gas specialists from North America to the New Zealand team and the opening of an East Coast Basin office in Napier to enable the Company to plan and execute a cost-effecitve long-term plan in the East Coast Basin.

PEP 38348 - (TAG 100%)

The Company is preparing to undertake the first phase of the drilling on the northern PEP 38348 permit with continued extensive consultation with all stakeholders, including local iwi, landowners and local and central government. Initial construction, surface lease access and drilling consent applications for the Punawai-1 well have been approved by regional and district councils. The Company has also secured a new surface access agreement to drill a well, referred to as Waitangi Valley-1 on the permit and the well consent application has been submitted for approval. The Company anticipates a well targeting the East Coast basin tight-oil source rocks in PEP 38348 will be drilled in early 2014.

PEP 38349 - (TAG 100%)

At the date of this report, data from logging of the Ngapaeruru-1 well is being studied by independent laboratories for expert analysis and initial data recovered and interpreted to date is encouraging. Detailed petrophysical evaluation continues with a full suite of unconventional logs to ascertain source rock quality, fracture identification, geochemistry, and rock moduli data. This data is critical to determining the most suitable completion method for production testing the Ngapaeruru-1 well, as well as to better understand the long term feasibility of TAG's East Coast Basin opportunity. Upon receipt of the final information related to completion options for Ngapaeruru-1, operations to complete the well will be planned with a goal to complete the well in calendar 2014.The Company also began planning for a 30km 2D seismic survey to be completed by May 2014 and initiated landowner and stakeholder engagement for a second well to be drilled on the permit in 2014.

PEP 53674 - (TAG 100%)

During the quarter, and at the date of this report, the Company completed the re-processing of 30 km of 2D seismic data and a field study to combine the data with a recently completed geochemical survey to enable greater understanding of the near surface geology of the permit. The results of this work will be analyzed to provide valuable insight to the development of the permit.

Canterbury Basin:

The Canterbury Basin is a frontier basin on New Zealand's South Island, with a proven onshore and offshore hydrocarbon system as evidenced by the presence of numerous oil and gas shows onshore and discoveries made offshore.. The Company controls 1.17 million acres of conventional and unconventional targets in a permit that spans onshore as well as shallow offshore, with water less than 100 meters deep. The onshore / offshore permit holds considerable promise and is optimally located within the migration pathway of a proven working hydrocarbon system. Anadarko Petroleum, which is slated to bring a jack-up rig to New Zealand in early 2014, estimates +150 mmbls, or several trillion cubic feet of gas in each of their offshore Canterbury permits. Shell is also scheduled to drill nearby offshore in 2014, and Australian explorer Beach Energy entered the basin with an offshore permit award in October 2012 to the North of TAG's PEP 52589.

PEP 52589 (TAG 100%):

The Company evaluated the 80km of new onshore 2D seismic data the Company acquired in November 2012 over leads initially identified using geochemical surface data has identified a number of leads and prospects within the permit. Based on the success of the initial seismic acquisition the Company has concluded that a futher 40km of 2D seismic data would be beneficial to allow better understanding of the closure and aerial extent of four newly mapped features as well as better understanding the potential resource within this frontier acreage. Based on the results and interpretation of the proprietry 2D seismic data the Company be in a position to evaluate a drilling commitment. On September 13, 2013 a change of conditions was approved by New Zealand Petroleum and Minerals to acquire, process and interpret 40km of 2D seismic data before committing to drill a well.

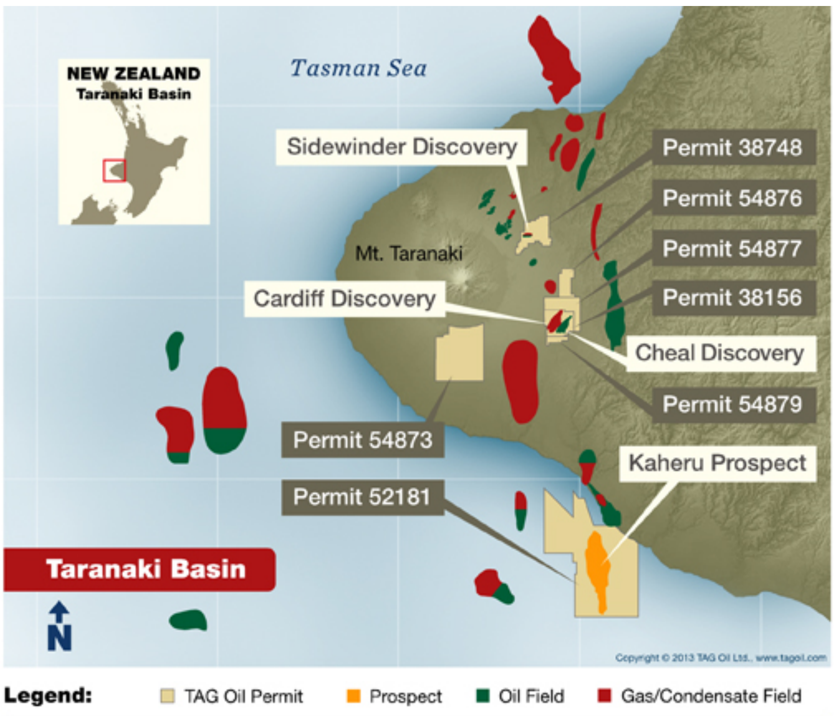
Opunake Hydro Limited ("OHL") and Coronado Resources Limited ("Coronado"):

On September 28, 2013, the Company sold its 90% stake in OHL to Coronado Resources Ltd in exchange for common shares of Coronado valued at approximately $3.6 million. The common shares of Coronado that have been issued to TAG and the vendor of the remaining 10% interest represents full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction increases TAG's shareholding in Coronado from 40% to 49% and accordingly Cornado is consolidated into the TAG group accounts at September 30, 2013.

CAPITAL EXPENDITURES

For the three months ended September 30, 2013, the Company invested $4,998,787 on its oil and gas exploration and evaluation assets compared to $2,043,123 invested last year and $9,367,133 was spent on proved oil and gas properties and OHL compared to $20,141,779 last year. For the six months ended September 30, 2013, the Company invested $12,091,693 in oil and gas exploration and evaluation assets compared to $2,824,629 last year and $14,541,962 was invested on proved oil and gas properties and OHL compared to $30,446,252 last year.

Taranaki Basin:



Permit	Ownership Interest	2014 Q2	Q1	2013 Q2	Six months ended 2014	2013
Mining Permits						
PMP 38156	100%	**7,531,518**	295,156	18,639,346	**7,826,674**	27,684,686
PMP 53803	100%	**1,062,010**	1,878,205	1,502,433	**2,940,215**	2,761,566
		8,593,528	2,173,361	20,141,779	**10,766,889**	30,446,252
Exploration Permits						
PEP 38748	100%	**130,190**	1,496,668	-	**1,626,858**	-
PEP 54873	100%	**1,307,287**	190,322	-	**1,497,609**	-
PEP 54876	50%	**48,873**	449	-	**49,322**	-
PEP 54877	70%	**2,707,522**	73,770	-	**2,781,292**	-
PEP 54879	50%	**108,177**	449	-	**108,626**	-
PEP 52181	40%	**188,577**	207,560	9,000	**396,137**	101,520
		4,490,626	1,969,218	9,000	**6,459,844**	101,520
OHL	90%	**773,605**	3,001,468	-	**3,775,073**	-
Total Taranaki Basin		**13,857,759**	7,144,047	20,150,779	**21,001,806**	30,547,772

Capital expenditures at Cheal for Q2 2014 of $7.5 million related to the Company's share of lease and drilling costs along with the purchase of materials and installation of facilities for the joint venture permit PEP 54877 to allow testing of the Cheal-E1, Cheal-E2 and Cheal-E3 wells The Company has constructed and owns the Cheal E-site facilities 100% and will charge a fee to the PEP 54877 joint venture to use the facilities based on the share of oil and gas throughput used by the joint venture. As a result, capital expenditures were higher in Q2, 2014 compared to Q1, 2014. Expenditure at Cheal in Q2, 2013 of $18.6 million is higher than the comparable quarter in fiscal 2014 as the Company invested in the Cheal facilities upgrade and drilling activities in in the prior year. At the Sidewinder oil and gas field the Company invested $1.1 million related to tie-ins and minor facilities upgrades which is lower than Q1, 2014 and the comparable period last year where expenditures were invested in drilling activities.

The Company invested $4.5 million in exploration permits in the Taranaki basin during Q2 2014, including:

a) PEP 54873 where $1.3 million was incurred related to long-lead items and consenting of a lease for the drilling of the deep Heatseeker well.
b) PEP 54877 where $2.7 million was incurred related to the Company's share of drilling and lease construction costs for the Cheal-E1, Cheal-E2 and Cheal-E3 wells.
c) investment in the remaining Taranaki exploration permits of $0.5 million related to general exploration costs.

OHL's capital expenditure in Q2 2014 consisted of installation costs related to a third one megawatt gas fired genset to accompany the existing two single megawatt gensets at the Cheal-A site.

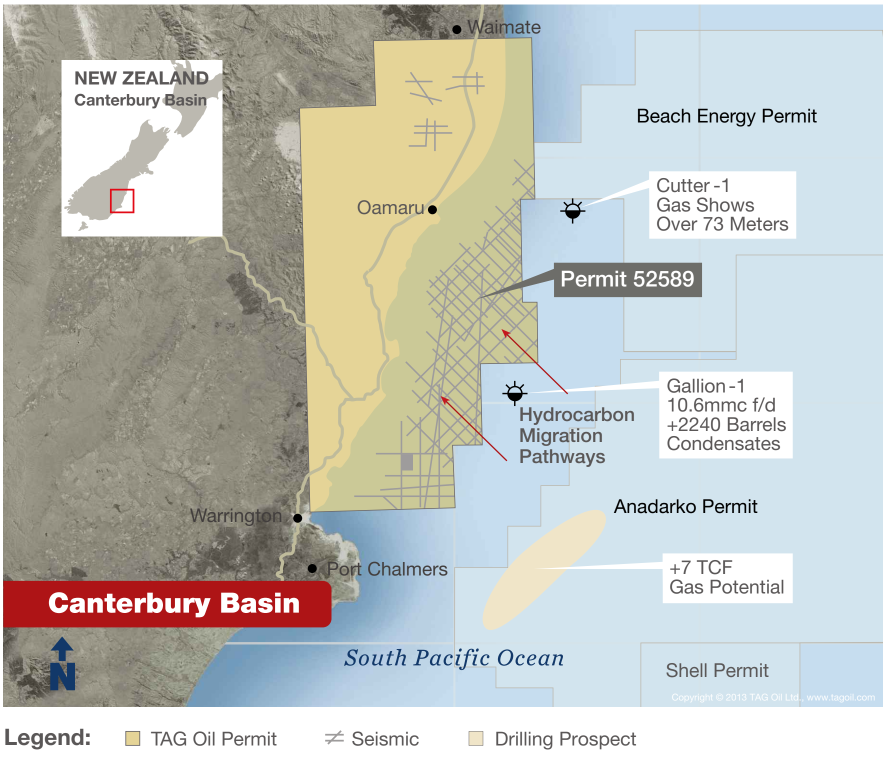
East Coast Basin:

Permit	Ownership Interest	2014		2013	Six months ended	
		Q2	Q1	Q2	**2014**	2013
PEP 38348	100%	**91,122**	60,501	46,941	**151,623**	361,669
PEP 38349	100%	**179,812**	4,942,496	(99,227)	**5,122,308**	20,075
PEP 50940 (1)	100%	**208,329**	-	-	**208,329**	-
PEP 53674	100%	**8,465**	39,510	695,470	**89,646**	780,455
PEP 52676(1)	100%	**15,348**	81,181	695,470	**54,858**	780,455
		503,076	5,123,688	1,338,654	**5,626,764**	1,942,654

(1) Permits relinquished during quarter ended September 30, 2013

Total expenditures on the East Coast permits in Q2 2014 were primarily incurred in consenting and general exploration expenditures compared to Q1 2014 where the major expenditure was drilling the Ngapaeruru-1 well.

Canterbury Basin:



Permit	Ownership Interest	2014		2013	Six months ended	
		Q2	Q1	Q2	**2014**	2013
PEP 52589	100%	5,085	-	695,470	5,085	780,455
		5,085	-	695,470	5,085	780,455

United States:

Total expenditures relate to recording the fair value of the Madison mining assets on consolidation to the TAG accounts following the transfer of OHL to Coronado for shares.

Operation	Ownership Interest	2014		2013	Six months ended	
		Q2	Q1	Q2	**2014**	2013
Madison mine - exploration	100%	**2,684,543**	-	-	**2,684,543**	-
Madison mine - development	100%	**670,199**	-	-	**670,199**	-
		3,354,742	-	-	**3,354,742**	-

SUMMARY OF QUARTERLY INFORMATION

	2014		**2013**				**2012**	
	Q2 **$**	**Q1** **$**	**Q4** **$**	**Q3** **$**	**Q2** **$**	**Q1** **$**	**Q4** **$**	**Q3** **$**
Total revenue	**15,884,584**	14,698,198	12,297,777	10,851,223	9,616,276	11,825,925	16,701,663	12,976,714
Costs	**(4,826,074)**	(4,954,663)	(3,947,730)	(3,289,307)	(3,123,182)	(3,680,324)	(5,382,240)	(4,280,725)
Foreign exchange	**(1,011,928)**	145,971	426,343	(69,453)	(474,603)	280,575	181,318	(129,433)
Stock option compensation	**(558,633)**	(937,898)	(1,276,261)	(2,004,076)	(1,499,954)	(840,721)	(1,137,058)	(1,590,387)
Other (costs) / income	**(7,046,147)**	(5,430,999)	(7,483,238)	(4,849,866)	(4,819,833)	(2,866,212)	(3,475,940)	(2,650,559)
Net income (loss)	**2,411,802**	3,520,609	16,891	638,521	(301,296)	4,719,243	6,887,743	4,325,610
Basic income (loss) per share	**0.04**	0.06	0.00	0.01	(0.01)	0.09	0.12	0.08
Diluted income (loss) per share	**0.04**	0.06	0.00	0.01	(0.00)	0.08	0.12	0.08
Production (BOE/d)	**2,100**	2,354	1,691	1,727	1,848	1,721	2,157	2,032
Capital expenditures (1)	**14,466,488**	12,349,082	20,032,321	21,116,096	22,203,753	11,112,181	12,924,484	12,164,822
Operating cash flow *(2)*	**8,562,643**	8,468,130	18,136,293	5,610,691	4,409,684	7,443,881	10,853,666	7,169,637

(1) Capital expenditures for the six months ended September 30, 2013 include costs amounting to $3,354,742 related to the acquisition of the Madison Mine owned by Coronado Resources

(2) Operating cash flow is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital

Revenue, daily production and operating cash flow have increased by 65%, 14% and 94% respectively when compared with the same quarter last year due to higher oil and gas production at Cheal following the commissioning of the Cheal gas plant in March 2013. Net income of $2,411,802 for Q2 2014 when compared to the net loss of $301,296 for the same period last year is primarily due to an increase in oil and gas sales volume and pricing in Q2 2014 that were partially offset with with a $0.4 million increase in depletion due to higher production rates, a $0.5 million increase in foreign exchange loss, a $0.9 million decrease in stock based compensation and a $0.2 million increase in wage and salaries required to manage the expanded business.

The Company continues to have a strong capital expenditure program based around cash provided from operating activities and a strong balance sheet. As noted above in fiscal 2014, the Company has drilled three shallow wells and has made significant progress on our first deep gas/condensate well. The Company will continue to develop the Taranaki Basin permits over many years and plans to drill another six shallow wells and a second deep gas/condensate well within the next 6 to 9 months. Successful discoveries from the drillling campaign can be placed efficiently into production using the existing 100% TAG owned Cheal and Sidewinder facilities.

RESULTS FROM OPERATIONS

Oil and Natural Gas Production, Pricing and Revenue

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Daily production volumes(1)					
Oil (bbls/d)	**1,209**	1,075	738	**1,143**	930
Natural gas (BOE/d)	**891**	1,279	1,110	**1,084**	854
Combined (BOE/d)	**2,100**	2,354	1,848	**2,227**	1,784
Daily sales volumes(1)					
Oil (bbls/d)	**1,227**	1,058	741	**1,142**	929
Natural gas (BOE/d)	**782**	1,115	876	**948**	616
Combined (BOE/d)	**2,009**	2,173	1,617	**2,090**	1,545
Natural Gas (Mmcf/d)	**4,694**	6,690	5,259	**5,687**	3,697
Product pricing					
Oil ($/bbl)	**113.30**	104.87	109.97	**109.42**	108.41
Natural gas ($/Mcf)	**5.18**	5.72	4.38	**5.50**	4.44
Sales					
Total revenue – gross	**$15,884,584**	$14,698,198	$9,616,276	**$30,582,782**	$21,442,201
Less other revenue – gross	**(861,603)**	(1,120,919)	-	**(1,982,522)**	-
Oil and natural gas revenue – gross	**15,022,981**	13,577,279	9,616,276	**28,600,260**	21,442,201
Oil and natural gas royalties(2)	**(1,632,648)**	(1,473,864)	(1,077,031)	**(3,106,512)**	(2,406,572)
Oil and natural gas Revenue – net	**$13,390,333**	$12,103,415	$8,539,245	**$25,493,748**	$19,035,629

(1) Natural gas production converted at 6 Mcf:1BOE (for BOE figures)
(2) Includes a 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field
(3) Other revenue is electricity revenue related to OHL.

Oil and natural gas gross revenue increased 56% in the quarter ended September 30, 2013, compared to the same period last year. The increase in revenue is attributable to a 24% increase in sales volume (on a BOE basis), a 18% increase in natural gas prices and a 3% increase in oil prices.

Oil production was 64% higher in the quarter ended September 30, 2013 compared to the same period last year due to the Cheal facility upgrade being completed. Oil production was 12% higher in the quarter ended September 30, 2013 compared to the quarter ended June 30, 2013, due to improved reliability of the Cheal facilities and fewer work-overs completed in Q2 2014.

Natural gas production was 20% lower and 30% lower on a BOE per day basis in the quarter ended September 30, 2013 compared to the quarter ended September 30, 2012 and the quarter ended June 30, 2013, respectively. The decrease in both cases is due to the natural decline in the Sidewinder wells in Q2, 2014.

Production by area (BOE/d)	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Cheal	**1,482**	1,523	897	**1,503**	1,107
Sidewinder	**618**	831	951	**724**	677
	2,100	2,354	1,848	**2,227**	1,784

During the six months ended September 30, 2013, the Cheal and Sidewinder oil and gas fields produced 209,130 (2013: 170,247) gross barrels of oil and 1,190 Mmcf (2013: 938 Mmcf) of natural gas and sold 209,113 (2013: 170,058) gross barrels of oil and 1,041 Mmcf (2013: 677 Mmcf) of natural gas.

During the three months ended September 30, 2013, the Cheal and Sidewinder oil and gas fields produced 111,268 (2013: 67,857) gross barrels of oil and 492 Mmcf (2013: 612 Mmcf) of natural gas and sold 112,852 (2013: 68,178) gross barrels of oil and 432 Mmcf (2013: 484 Mmcf) of natural gas.

Royalties

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Royalties	**1,632,648**	1,473,864	1,077,031	**3,106,512**	2,406,572
As a percentage of revenue	**10%**	10%	11%	**10%**	11%

Royalties increased 52% and 29% in the three and six months ended September 30, 2013 respectively when compared to the comparative periods ended September 30, 2012 due to higher revenues being generated in the 2014 fiscal year. The Royalty, as a percentage of revenue, decreased from 11% in the three and six months ended September 30, 2012 to 10% in the comparative periods in fiscal 2014, as no royalty is paid on gas sold from either Cheal or Sidewinder under the agreement to acquire of the Cheal oil and gas field and Sidewinder exploration permit.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received in the first six months of fiscal year 2014 and a 7.5% royalty paid on net oil proceeds from Cheal as part of the Company's agreement to acquire a 69.5% interest in the Cheal oil and gas field. The Sidewinder overriding royalty agreement requires TAG to pay a 5% royalty on net sales revenue on the first 200,000 barrels of oil produced from the date of acquisition and then dropping to a 2.5% royalty on net oil sales revenue thereafter. At September 30, 2013, 12,797 barrels of oil (September 30, 2012: 7,132) had been produced from the date of the PMP 53803 (formerly PEP 38748) permit acquisition leaving 187,203 (September 30, 2012: 192,868) barrels of production required before the royalty reduction to 2.5%. Sidewinder royalties also include a 3.33% royalty on net oil and gas proceeds payable to a previous partner.

Production, Transportation and Storage

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Total production costs	**2,270,017**	2,582,020	1,424,168	**4,852,037**	2,826,287
Electricity production costs	**(633,886)**	(743,757)	-	**(1,377,643)**	-
Oil and gas production costs*	**1,636,131**	1,838,263	1,424,168	**3,474,394**	2,826,287
Per BOE ($)	**8.47**	8.58	8.38	**8.53**	8.65
Transportation and storage costs	**923,409**	898,779	621,983	**1,822,188**	1,570,647
Per BOE ($)	**4.78**	4.20	3.66	**4.47**	4.81

* Production costs are oil and gas costs only. Electricity produciton costs related to OHL are excluded from the production numbers above

Total production costs decreased 1% from Q1, 2014 to Q2, 2014 despite a decrease in production volume due to higher facilities reliability in Q2, 2014. Production costs per BOE also decreased as a result and will continue to be monitored for areas to increase efficiency. Oil and gas production costs were 15% higher in dollar terms and 1% higher on a BOE basis in Q2, 2014 when compared to the same quarter last year due to increased costs of operating of the Cheal gas processing plant commissioned in March 2013.

Electricity production costs to September 30, 2013 were lower than the costs for the quarter ended June 30, 2013 as there was less demand due to the seasonal nature business operations.

Transportation and storage costs have increased 31% per BOE in the quarter ended September 30, 2013, compared to the same period last year and have increased 14% from the quarter ended June 30, 2013. The increase is due to a higher proportion of oil to natural gas produced in Q2, 2014 (natural gas does not incur transportation or storage costs).

Oil and Gas Operating Netback ($/BOE)

	2014		2013	Six months ended	
($/BOE)	**Q2**	Q1	Q2	**2014**	2013
Oil and gas revenue	**81.28**	63.38	56.56	**74.76**	65.65
Royalties	**(8.45)**	(6.88)	(6.34)	**(7.62)**	(7.37)
Transportation and storage costs	**(4.78)**	(4.20)	(3.66)	**(4.47)**	(4.81)
Production costs	**(8.47)**	(8.58)	(8.38)	**(8.53)**	(8.65)
Netback per BOE ($)	**59.58**	43.72	38.18	**54.14**	44.82

Operating netback is the operating margin the company receives from each barrel of oil equivilent sold. The netback on a BOE basis for the current quarter is 56% higher when compared to the netback in the same period last year and 36% higher than the netback for the quarter ended June 30, 2013. The higher per BOE revenue, royalties and transportation and storage costs in Q2, 2014 compared to the Q1, 2014 and Q2, 2013 are due to a higher proportion of oil produced from Sidewinder and Cheal oil and gas fields as natural gas has a lower price per BOE and does not incur transportation charges.

Emmissions Trading Scheme

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Emmissons trading scheme ($)	**(26,171)**	9,888	185,265	**(16,283)**	237,043
Per BOE ($)	**(0.14)**	(0.14)	1.09	**(0.04)**	.073

ETS costs were negative in the quarter and six months to September 30, 2013 as decreased carbon unit prices reversed amounts accrued at earlier higher prices.

Insurance

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Directors and officers insurance	**11,578**	11,577	12,693	**23,155**	27,618
Insurance	**159,143**	104,682	78,495	**263,825**	184,167
	170,721	116,259	91,188	**286,980**	211,785
Per BOE ($)	**0.88**	0.54	0.54	**0.70**	0.65

Insurance increased 36% during the six months ending September 30, 2013 from $286,980 to $211,785 due to generally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

Equity Loss in Associated Companies

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Loss in Associate ($)	**164,329**	57,312	17,462	**221,641**	17,462

On September 28, 2013, the Company sold its share of OHL to Coronado Resources Limited ("Coronado") increasing its shareholding in Coronado from 40% to 49% and gaining a controlling interest. Coronado was fully consolidated at September 30, 2013 and the share of loss incurred under equity accounting for the Coronado investment before acquiring control is recorded in the compresensive statement of profit and loss. The increase in loss for Q2, 2014 compared to Q2 2013 and Q1, 2014 is due to higher costs related to the OHL acquisition.

General and Administrative Expenses ("G&A")

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Consulting fees	**126,047**	65,834	190,171	**191,881**	211,187
Directors fees	**77,297**	76,796	66,000	**154,093**	130,500
Filing, listing and transfer agent	**11,891**	65,896	72,268	**77,787**	167,954
Reports	**128,173**	12,398	334,338	**140,571**	464,462
Office and administration	**140,618**	164,041	123,302	**304,659**	222,639
Professional fees	**64,553**	168,306	228,813	**232,859**	262,966
Rent	**65,501**	62,035	62,434	**127,536**	120,190
Shareholder relations and communications	**91,266**	144,617	27,541	**235,883**	157,046
Travel	**119,783**	110,663	74,878	**230,446**	190,218
Wages and salaries	**707,113**	606,092	463,152	**1,313,205**	792,738
Overhead recoveries	**(4,216)**	-	-	**(4,216)**	-
	1,528,026	1,476,678	1,642,897	**3,004,704**	2,719,900
Per BOE ($)	**7.91**	6.89	9.66	**7.37**	8.33

G&A costs have decreased by 18% on a per BOE basis in Q2, 2014 when compared with the same quarter last year and have increased by 15% when compared to the quarter ended June 30, 2013. In the six months to September 30, 2013 G&A costs have increased by 10% but decreased by 12% on a BOE basis compared to the comarative period last year.

Consulting fees have decreased in Q1, 2014 and Q2, 2014 compared to Q2, 2013 due to the company employing more permenant staff in New Zealand to resource the company to support the growth of the Company's expanded operations in the current year. The increase in consulting fees from Q2, 2014 compared to Q1, 2014 was primarily due to technical studies undertaken by the Company's consultants. Professional fees have decreased in the quarter and six months ended September 30, 2013, compared to the same periods last year, as costs were higher in the prior periods due to legal costs incurred related to the Company's dispute with a former employee.

Shareholder relations and communications have increased in the quarter and six months ended September 30, 2013, compared to the same periods last year due to joining the Petroleum Exploration and Production New Zealand association and ongoing corporate activities associated with shareholder communication. Reports expenditure has increased in the quarter and six months ended September 30, 2013 compared to last year due to more work undertaken on the Cheal and Sidewinder oil and gas fields last year. The increase in reports for Q2, 2014 compared to Q1, 2014 is due to work commissioned on the Company's deep prospect inventory.

Office and administration costs, travel and wages and salaries have increased in the first six months of fiscal year 2014, compared to last year as the Company has moved several staff from consulting to permanent employment contracts and also employed more staff to support expanded activities related to drilling, operations, acquisitions and financing and converted consultants to permanent employees.

Share-based Compensation

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Share-based compensation	**558,633**	937,898	1,499,954	**1,496,531**	2,340,675
Per BOE ($)	**2.89**	4.38	8.82	**3.67**	7.17

Share-based compensation costs are non-cash charges which reflect the estimated value of stock options granted and the Company applies the Black-Scholes option pricing model using the closing market prices on the grant dates and to date the Company has calculated option benefits using a volatility ratio of 75% and a risk free interest rate of 2.5% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

The Company recorded a 63% decrease in total share–based compensation costs in the quarter ended September 30, 2013 when compared with the same period last year. The decrease in total share-based compensation costs was due to options issued in the 2013 fiscal year having a higher option value assigned to each option grant due to the the Company's higher share price at the time of grant as well as more options being fully vested and amortised in the comparable 2013 fiscal year periods than in the 2014 fiscal year to date.

In the quarter ended September 30, 2013, the Company granted nil (2013: 1,395,000) options and nil (2013: 180,832) options were exercised at a weighted average price of $nil (2013: $3.60) per share. In the six months ended September 30, 2013, the Company granted $nil (2013: 1,395,000) options and 71,429 (2013: 180,832) options were exercised at a weighted average price of $3.00 (2013: $8.32) per share.

Depletion, Depreciation and Accretion

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Depletion, depreciation and accretion	**3,608,171**	3,911,450	3,198,014	**7,519,621**	5,083,810
Per BOE ($)	**18.68**	18.26	18.81	**18.46**	15.57

Depletion, depreciation and accretion increased 48% in the first six months of fiscal year 2014, compared to the same period in fiscal year 2013 and increased 13% in Q2, 2014 compared to Q2, 2013. The increase in depletion is due to the additional capital costs of the new Sidewinder wells and increased initial natural gas production in the six months from these wells based on the 2P reserves calculated at March 31, 2013 and used for the units of production depletion calculation. Depletion at Cheal is also higher reflecting the higher drilling costs subject to depletion associated with last years drilling campaign.

Foreign Exchange (Gains) / Losses

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Foreign exchange (gain) / loss ($)	**1,011,928**	(145,971)	474,603	**865,957**	194,028

The foreign exchange loss for the current quarter and year to date was caused by fluctuations of both the U.S. dollar and New Zealand dollar in comparison to the Canadian dollar.

Interest Income

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Interest income	**188,792**	181,601	314,993	**370,393**	583,955

Decreased interest income for fiscal year 2014 to date reflects the lower cash balances held when compared to comparative quarters in fiscal year 2013.

Net Income and Operating Margin

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Net income ($)	**2,411,802**	3,520,609	(301,296)	**5,932,411**	4,417,947
Per share, basic ($)	**0.04**	0.06	(0.01)	**0.10**	0.07
Per share, diluted ($)	**0.04**	0.06	0.00	**0.09**	0.07

Operating margin increased by $2.7 million in Q2, 2014, compared to Q2, 2013 due to a $6.3 million increase in revenue, a $1.1 million increase in production, transportation and storage costs and a $0.6 million increase in royalty costs as a result of higher production at Cheal and Sidewinder. The increase in operating margin was partially offset by a $0.4 million increase in depreciation, depletion and accretion, a $0.9 million decrease in share-based compensation, a $0.1 million decrease in general and administrative costs and a $0.5 million increase in foreign exchange gain in the quarter ended September 30, 2013 compared to the quarter ended September 30, 2012.

For the six months ended September 30, 2013, the Company generated a 34% increase in net income compared to the same period last year and due to a 43% increase in revenue from higher production at both Cheal and Sidewinder and after considering increased depletion, increased salaries and wages and decreased share based compensation as discussed above.

Cash Flow

	Six months ended	
	2014	2013
Operating cash flow ($) *(1)*	**17,030,773**	11,853,565
Cash provided by operating activities ($)	**14,156,153**	14,981,452
Per share, basic ($)	**0.24**	0.25
Per share, diluted ($)	**0.23**	0.24

(1) Operating cash flow is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital

Operating cash flow increased 44% from $11.9 million in the six months to September 30, 2012 to $17.0 million in the six months to September 30, 2013 as a result of higher sales of oil in gas and lower propotional increases in transportation and storage and royalties as gas sales do not incur transportation charges or some third party royalties as detailed above.

A $2.3 million increase in receivables related to the timing of payments from oil sales and a $1.5 million increase in inventory on hand during the six-month period ended September 30, 2013 was responsible for a decrease in cash provided by operating activities reported for the quarter ended September 30, 2013 when compared with the six months ended September 30, 2012.

Cash provided by operating activities decreased 6% in the six months ended September 30, 2013 compared to the six months ended September 30, 2012. The decrease in the curent year, despite an increase in net income after adding back non-cash operating items, was due to the previoulsy mentioned increase in receivables compared to a $1.8 million decrease last year related to the timing of payments from oil sales the increase in inventory compared to a $1.3 million decrease last year.

The Company had the following commitments for Capital Expenditure at September 30, 2013**:**

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases *(1)*	756,574	259,243	497,331
Other long-term obligations *(2)*	77,244,000	43,639,000	33,605,000
Total Contractual Obligations *(3)*	**78,000,574**	**43,898,243**	**34,102,331**

(1) The Company has commitments relating to office leases situated in New Plymouth, New Zealand and Vancouver.

(2) The Other Long Term Obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report that relate to operations and infrastructure. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

(3) The Company's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

The details of the Company's material commitments shown above are as follows

Permit	Commitment	Less than One Year $	More than One Year $
PMP 38156	Workovers, optimisations and lease improvements	3,780,000	
	Drill 1 deep gas well in Cardiff structure	8,156,000	
PMP 53803	Workovers, optimisations and lease improvements	683,000	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	13,990,000	
PEP 54876 (1)	Drilling of one shallow exploration well and reprocess 2D seismic	1,386,000	
PEP 54877 (1)	Drilling of three shallow exploration wells	5,823,000	
PEP 54879 (1)	Drilling of two shallow exploration wells	2,773,000	
PEP 38748	Drilling of two shallow exploration wells and lease improvements	53,000	4,280,000
PEP 50940	Nil	-	
PEP 52181	Drilling Kaheru-1	106,000	16,593,000
PEP 52589	Permit costs and 2D seismic	890,000	
PEP 52676	Permit costs and geochemical sampling	704,000	
PEP 53674	Permit costs and geochemical sampling	85,000	
PEP 38348	Drilling of two shallow exploration wells and 2D seismic acquisition	5,104,000	6,480,000
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	106,000	6,252,000
TOTAL COMMITMENTS		**43,639,000**	**33,605,000**

(1) The commitment does not include the cost of wells funded by the Company's joint venture partner.

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the SuppleJack wells previoulsy drilled. The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments. Commitments and work programs are subject to change.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2013, the Company had $61.2 million (September 30, 2012: $86.1 million) in cash and cash equivalents and $62.9 million (September 30, 2012: $84.5 million) in working capital. As of the date of this report the Company is adequately funded to meet its planned operations and ongoing requirements for the next twelve months based on the current exploration and development programs and anticipated revenue from the Cheal and Sidewinder oil and gas fields.

Additional material commitments, changes to production estimates or any acquisitions by the Company may require a source of additional financing. Alternatively certain permits may be farmed-out, sold or relinquished.

Please refer to subsequent events for additional information.

NON-GAAP MEASURES

The Corporation uses certain terms for measurement within this MD&A that do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP"), including IFRS, and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "operating cash flow", "operating netback" and "operating margin" are not recognized measures under the applicable IFRS. Management of the Corporation believes that these terms are useful to provide shareholders and potential investors with additional information, in addition to profit and loss and cash flow from operating activities as defined by IFRS, for evaluating the Corporation's operating performance and leverage. References to operating cash flow are to cash revenue less direct operating expenses, which includes operations and maintenance expenses and taxes (other than income and capital taxes) but excludes general and administrative expenses. Operating netback denotes oil and gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses.

Operating cash flow

	Six months ended	
	2014	2013
Cash provided by operating activities	**14,156,153**	14,981,452
Changes for non cash working capital accounts	**2,874,620**	(3,127,887)
Operating cash flow	**17,030,773**	11,853,565

Operating netback

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Total revenue	**$15,884,584**	$14,698,198	$9,616,276	**$30,582,782**	$21,442,201
Less electricity revenue	**(861,603)**	(1,120,919)	-	**(1,982,522)**	-
Oil and natural gas revenue	**15,022,981**	13,577,279	9,616,276	**28,600,260**	21,442,201
Less oil and natural gas royalties	**(1,632,648)**	(1,473,864)	(1,077,031)	**(3,106,512)**	(2,406,572)
Less transportation and storage costs	**(923,409)**	(898,779)	(621,983)	**(1,822,188)**	(1,570,647)
Less total production costs	**(2,270,017)**	(2,582,020)	(1,424,168)	**(4,852,037)**	(2,826,287)
Add back electricity production costs	**633,886**	743,757	-	**1,377,643**	-
Operating Netback	**10,830,793**	9,366,373	6,493,094	**20,197,166**	14,638,695

Operating margin

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Revenue	**$15,884,584**	$14,698,198	$9,616,276	**$30,582,782**	$21,442,201
Less oil and natural gas royalties	**(1,632,648)**	(1,473,864)	(1,077,031)	**(3,106,512)**	(2,406,572)
Less production costs	**(2,270,017)**	(2,582,020)	(1,424,168)	**(4,852,037)**	(2,826,287)
Less transportation and storage costs	**(923,409)**	(898,779)	(621,983)	**(1,822,188)**	(1,570,647)
Operating Margin	**11,058,510**	9,743,535	6,493,094	**20,802,045**	14,638,695

OFF-BALANCE SHEET ARRANGEMENTS AND PROPOSED TRANSACTIONS

The Company has no off-balance sheet arrangements or proposed transactions.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Financial instruments on the Company's balance sheet include cash, accounts receivable and accounts payable. The carrying value of these instruments approximates their fair value due to the short term nature of the instruments. The Company manages its risk through its policies and procedures, but generally has not used derivative financial instruments to manage risks other than managing electricity pricing risk through hedges that approximate electricity consumption for third party's.

RELATED PARTY TRANSACTIONS

As required under IAS 24, related party transactions include compensation paid to the Company's CEO, COO, Chairman, and CFO as well as to the remaining board of directors as part of the ordinary course of the Company's business. The Company reports that no related party transactions have occurred during the reporting period other than ongoing compensation as disclosed in the table below.

The Company is of the view that the amounts incurred for services provided by related parties approximates what the Company would incur to arms-length parties for the same services. Compensation paid to key management personnel for the six months ended September 30:

	2014		2013	Six months ended	
	Q2	Q1	Q2	**2014**	2013
Share-based compensation	**321,823**	$568,620	$1,065,007	**890,443**	$1,699,028
Management wages and director fees	**254,396**	245,629	251,353	**500,025**	498,216
Total management compensation	**576,219**	$814,249	$1,316,360	**1,390,468**	$2,197,244

SHARE CAPITAL

a. At September 30, 2013, there were 59,170,252 common shares outstanding
b. At November 14, 2013, there were 64,870,252 common shares outstanding and there are 3,708,334 stock options outstanding, of which 3,143,334 have vested.

The Company has one class of common shares. No class A or class B preference shares have been issued.

Please refer to Note 10 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

On October 7, 2013 the Company announced the appointment of Mr. Chris Ferguson as its Chief Financial Officer, replacing Mr. Blair Johnson effective December 1, 2013.

The Company concluded an agreement whereby the Underwriters agreed to purchase, on a bought deal basis for resale to the public, 5,700,000 common shares (the "Common Shares") of the Company at a price of $4.40 per Common Share for aggregate gross proceeds of $25,080,000 (the "Offering"). The Company has also granted the Underwriters an option to purchase, on the same terms as the Offering, up to an additional 855,000 Common Shares at a price of $4.40 per Common Share for additional gross proceeds of $3,762,000 (the "Over-Allotment Option"). The Over-Allotment Option is exercisable in whole or in part at any time prior to 30 days after the Closing Date (as defined herein). In the event that the option is exercised in its entirety, the aggregate gross proceeds of the Offering will be approximately $28,842,000.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the condensed consolidated interim financial statements requires management to make estmates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these condensed consolidated interim financial statements. Further information on the Company's critical accounting estimates can be found in the notes to the consolidated annual financial statements and the annual MD&A for the year ended March 31, 2013. There have been no changes to the Company's critical accounting estimates as of September 30, 2012.

BUSINESS RISKS AND UNCERTAINTIES

The Company, like all companies in the international oil and gas sector, is exposed to a variety of risks which include title to oil and gas interests, the uncertainty of finding and acquiring reserves, funding and developing those reserves and finding storage and markets for them. In addition there are commodity price fluctuations, interest and exchange rate changes and changes in government regulations. The oil and gas industry is intensely competitive and the Company must compete against companies that have larger technical and financial resources. The Company works to mitigate these risks by evaluating opportunities for acceptable funding, considering farm-out opportunities that are available to the Company, operating in politically stable countries, aligning itself with joint venture partners with significant international experience and by employing highly skilled personnel. The Company also maintains a corporate insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts and other operating accidents and disruptions. The oil and gas industry is subject to extensive and varying environmental regulations imposed by governments relating to the protection of the environment and the Company is committed to operate safely and in an environmentally sensitive manner in all operations. There have been no significant changes in these risks and uncertainties in the first six months of the 2014 fiscal year. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

New Accounting Pronouncements

The Company adopted the following new IFRS standards effective April 1, 2013

(a) IFRS 10, *Consolidated Financial Statements,* IFRS 11, *Joint Arrangements,* IFRS 12, *Disclosure of Interests in Other Entities,* and amendments to IAS 27, *Separate Financial Statements* and IAS 28, *Investments in Associated and Joint Ventures:*

These five new standards establish control as the basis for consolidation and provide enhanced disclosure requirements for the Company's interests in other entities and the effects of those interests on the Company's financial statements. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Company assessed its consolidation conclusions on April 1, 2013, and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries or investees. IFRS 11 also had no impact as the Company had classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements. The Company will continue to include herein its proportionate share of the relevant assets and liabilities.

(b) IFRS 7*, Financial Instruments Disclosures*

This standard contains amendments relating to disclosure requirements for the offsetting of financial assets and liabilities when offsetting is permitted under IFRS. Amendments to IFRS 7 required minimal disclosure changes in the Company's financial statements as of March 31, 2013.

(c) IFRS 13, *Fair Value Measurement*:

This new standard provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Company adopted IFRS 13 on April 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at April 1, 2013.

(d) IFRS 19, *Employee benefits*

This standard includes fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. Amendments to IFRS 19 required minimal disclosure changes in the Company's financial statements as of March 31, 2013.

(e) IAS 1, *Presentation of Financial Statements*

The Company has adopted the amendments to IAS 1, Presentation of Financial Statements, effective April 1, 2013. These amendments require the Company to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

Accounting standards issued but not yet applied

In May 2013, the IASB released an amendment to IAS 36, "*Impairment of Assets"* . This amendment requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). The amendment is effective January 1, 2014. Early adoption is permitted.

Please refer to Note 2 of the March 31, 2013 audited consolidated financial statements.

Managements Report on Internal Control over Financial Reporting

Disclosure controls and procedures and internal controls over financial reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Any system of internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There have been no changes in the Company's internal control over financial reporting during the six months ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Additional information relating to the Company is available on Sedar at www.sedar.com.

FORWARD LOOKING STATEMENTS

The MD&A contains forward-looking statements within the meaning of securities laws, including the "safe harbour" provisions of Canadian securities legislation. Forward-looking statements and information concerning anticipated financial performance are based on management's assumptions using information currently available. Material factors or assumptions used to develop forward-looking information include drilling programs and results, facility and pipeline construction operations and enhancements, potential business prospects, unitization, growth strategies, the ability to add production and reserves through development and exploration activities, the ability to reduce costs and extend commitments, projected capital costs, government legislation, well performance, the ability to market production, the commodity price environment and quality differentials and exchange rates. Management also assumes that the Company will continue to be able to maintain permit tenures in good standing, that the Company will be able to access equity capital when required and that the Company will maintain access to necessary oil and gas industry services and equipment to conduct its operations. Although management considers its assumptions to be reasonable based on these factors, they may prove to be incorrect.

Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "assume", "believe", "estimate", "expect", "forecast", "guidance", "may", "plan", "predict", "project", "should", "will", or similar words suggesting future outcomes. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: oil and natural gas production estimates and targets, including those at Cheal and Sidewinder, including, without limitation, statements regarding BOE/d production capabilities, an increase in cash flow, reserves and reserve values through a properly executed development plan at Cheal and Sidewinder, including maximizing the value at Cheal through the implementation of further optimization operations, successful completion of infrastructure enhancements at Cheal and Sidewinder and additional successful drilling; anticipated revenue from the Cheal and Sidewinder oil and gas fields; converting the undiscovered resource potential to proved reserves within the East Coast Basin, completing announced exploration acquisitions; capital expenditure programs and estimates including those set out herein under "Use of Proceeds"; and the impact of the transition to International Financial Reporting Standards ("IFRS") on the Company's financial statements.

Because forward-looking information addresses future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking information. These risks and uncertainties include, but are not limited to: access to capital, commodity price volatility; well performance and marketability of production; transportation and refining availability and costs; exploration and development costs; infrastructure costs, the recoverability of reserves; reserves estimates and valuations; the Company's ability to add reserves through development and exploration activities; accessibility of services and equipment, fluctuations in currency exchange rates; and changes in government legislation and regulations.

The forward-looking statements contained herein are as of November 14, 2013, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

Undiscovered Hydrocarbon-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. There is no certainty that any portion of the undiscovered resources will be discovered or that, if discovered, it will be economically viable or technically feasible to produce.

Exploration for hydrocarbons is a speculative venture necessarily involving substantial risk. TAG's future success in exploiting and increasing its current reserve base will depend on its ability to develop its current properties and on its ability to discover and acquire properties or prospects that are capable of commercial production. However, there is no assurance that TAG's future exploration and development efforts will result in the discovery or development of additional commercial accumulations of oil and natural gas. In addition, even if further hydrocarbons are discovered, the costs of extracting and delivering the hydrocarbons to market and variations in the market price may render uneconomic any discovered deposit. Geological conditions are variable and unpredictable. Even if production is commenced from a well, the quantity of hydrocarbons produced inevitably will decline over time, and production may be adversely affected or may have to be terminated altogether if TAG encounters unforeseen geological conditions. TAG is subject to uncertainties related to the proximity of any reserves that it may discover to pipelines and processing facilities. It expects that its operational costs will increase proportionally to the remoteness of, and any restrictions on access to, the properties on which any such reserves may be found. Adverse climatic conditions at such properties may also hinder TAG's ability to carry on exploration or production activities continuously throughout any given year.

The significant positive factors that are relevant to the estimate contained in the independent resource assessment are:

- proven production in close proximity;
- proven commercial quality reservoirs in close proximity; and
- oil and gas shows while drilling wells nearby.

The significant negative factors that are relevant to the estimate contained in the independent resource assessment are:

- tectonically complex geology could compromise seal potential; and
- seismic attribute mapping in the permit areas can be indicative but not certain in identifying proven resource.

Disclosure provided herein in respect of BOE (barrels of oil equivalent) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Readers are further cautioned that disclosure provided herein in respect of well flow test results may be misleading, as the test results are not necessarily indicative of long-term performance or of ultimate recovery.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS
Garth Johnson
President, CEO, and Director
Vancouver, British Columbia

Alex Guidi, Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Ronald Bertuzzi, Director
Vancouver, British Columbia

Blair Johnson, CFO
Auckland, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

Randy Toone, Country Manager
New Plymouth, New Zealand

Giuseppe (Pino) Perone, Corporate Secretary
Vancouver, British Columbia

CORPORATE OFFICE
885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 3E8
Telephone: 1-604-682-6496
Facsimile: 1-604-682-1174

REGIONAL OFFICE
New Plymouth, New Zealand

SUBSIDIARIES
TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Limited
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited
DLJ Management Corp.
Coronado Resources Limited

BANKER
Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL
Blake, Cassels & Graydon
Vancouver, British Columbia

Bell Gully
Wellington, New Zealand

AUDITORS
De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT
Computershare Investor Services Inc.
100 University Avenue, 9th Floor
Toronto, Ontario
Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

ANNUAL GENERAL MEETING
The Annual General Meeting will be held on December 12, 2013 at 10:00am at the offices of Blake, Cassels & Graydon located at Suite 2600, 595 Burrard Street
Vancouver, B.C. V7X 1L3

SHARE LISTING
Toronto Stock Exchange (TSX)
Trading Symbol: TAO

OTCQX Trading Symbol: TAOIF

SHAREHOLDER RELATIONS
Telephone: 604-682-6496
Email: ir@tagoil.com

SHARE CAPITAL
At November 14, 2013, there were 64,870,252, shares issued and outstanding.
Fully diluted: 68,578,586 shares.

WEBSITE
www.tagoil.com