FORM 51-101F1
Statement of Reserves Data and Other Oil and Gas Information

PART 1: DATE OF STATEMENT

This statement of reserves data and other oil and gas information is dated 30 April 2018 and the effective date of the data is 31 December 2017.

References to oil, natural gas, natural gas liquids, reserves (gross, net, proved, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, constant prices and costs, operating costs, development costs, future net revenue and future income tax expenses, shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and Companion Policy 51-101CP.

All dollar figures are in Canadian dollars unless otherwise specified.

PART 2: DISCLOSURE OF RESERVES DATA

New Zealand Energy Corp. (the "**Company**") has one petroleum mining permit ("**PMP**") with reserves and two petroleum mining licenses ("**PML**") with reserves. The Permits are adjacent and located in the Taranaki Basin on the North Island of New Zealand.

Since December 2010 the Company has held a 100% interest in the Copper Moki PMP (split out of the Eltham Petroleum Exploration Permit in July 2014). The Company also holds a 50% interest in and has reserves attributable to the Waihapa and Ngaere PMLs.

The oil and natural gas reserves and net present value of future net revenue of the Copper Moki PMP and the Waihapa and Ngaere PMLs were evaluated by Deloitte LLP ("**Deloitte**"), which prepared a report regarding such reserves dated effective 31 December 2017 (the "**Reserve Report**").

The following tables are based on information contained in the Reserve Report, and calculations prepared by the Company, which show oil and natural gas reserves associated with the Company's Copper Moki, Waihapa and Ngaere permits and the net present value of estimated future revenue for these reserves using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance the forecast price and cost assumptions contained in the Reserve Report will be attained, and variances could be material. Assumptions relating to costs and other matters are included in the Reserve Report. The recovery and reserve estimates of the Company's oil and natural gas reserves included in this statement of reserves data are estimates only and there is no guarantee the estimated reserves will be recovered. Risks and uncertainties that could cause the actual reserves to differ from those anticipated include, but are not limited to, the underlying risks of the oil and gas industry (operational risks in development, exploration and production; potential delays or changes in plans with respect to work programs or expenditures; uncertainty of reserves estimates; uncertainty in production and cost projections; political and environmental factors), and commodity price and exchange rate fluctuations.

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 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 the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The term barrels of oil equivalent ("**BOE**") may be misleading, particularly if used in isolation. The Company uses a standard measure of six thousand cubic feet of natural gas ("**Mcf**") to one barrel of oil ("**bbl**" or "**stb**") when converting natural gas to barrels of oil equivalent, or BOE. This conversion ratio is based on an energy equivalency method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

OIL AND GAS RESERVES SUMMARY						
Forecast Pricing and Costs						
As at 31 December 2017						
	Light & Medium Oil		Natural Gas		Barrels Oil Equivalent	
Reserves Category	Gross[2] Mstb[1]	Net[3] Mstb	Gross MMcf[1]	Net MMcf	Gross Mboe[1]	Net Mboe
Proved						
Developed Producing	186.7	164.0	743.3	642.7	310.6	271.1
Developed Non-Producing	202.5	178.9	318.4	277.0	255.6	225.0
Undeveloped	129.3	111.2	116.3	100.2	148.6	127.9
Total Proved	**518.4**	**454.1**	**1,178.1**	**1,019.9**	**714.8**	**624.1**
Probable	248.2	217.5	455.4	395.7	324.1	283.4
Total Proved and Probable	**766.6**	**671.6**	**1,633.5**	**1,415.6**	**1,038.9**	**907.5**

Notes:

(1) Mstb – Thousand barrels; MMcf – Million cubic feet; MBOE – Thousand barrels of oil equivalent

(2) Gross reserves are the Company's working interest share before the deduction of royalty obligations payable to the New Zealand Government and Beach Energy Resources NZ (TAWN) Limited.

(3) Net reserves are the Company's working interest share after deduction of royalty obligations payable to the New Zealand Government and Beach Energy Resources NZ (TAWN) Limited

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE						
Before & After Tax						
Forecast Prices and Costs						
As at 31 December 2017						
	Net Present Value of Future Net Revenues Before and After Tax Discounted at %/year					
Reserves Category	0% $000	5% $000	10% $000	15% $000	20% $000	Unit Value 10% ($/BOE)
Proved						
Developed Producing	-462.4	214.9	489.8	627.9	702.0	1.81
Developed Non-Producing	9,634.8	6,131.6	4,319.4	3,276.2	2,606.8	19.19
Undeveloped	5,078.3	3,566.9	2,570.3	1,904.8	1,445.5	20.10
Total Proved	**14,250.7**	**9,913.4**	**7,379.4**	**5,808.8**	**4,754.3**	**11.82**
Probable	14,405.4	8,530.7	5,790.7	4,232.2	3,232.7	20.43
Total Proved Plus Probable	**28,656.2**	**18,444.1**	**13,170.1**	**10,041.0**	**7,987.0**	**14.51**

TOTAL FUTURE NET REVENUE							
Undiscounted							
Forecast Prices and Costs							
As at 31 December 2017							
	Revenue	Royalties	Operating Costs	Investment Costs	Abandonment Costs	Income Taxes	Revenue Before & After Income Taxes
Reserves Category	$000	$000	$000	$000	$000	$000	$000
Proved							
Developed Producing	22,753.0	2,829.2	12,084.7	0.0	8,301.7	0.0	-462.4
Developed Non-Producing	23,338.5	2,842.4	8,976.8	1,339.0	545.4	0.0	9,634.8
Undeveloped	13,633.3	1,909.1	4,141.0	2,065.4	439.5	0.0	5,078.3
Total Proved	**59,724.8**	**7,580.7**	**25,202.4**	**3,404.4**	**9,286.6**	**0.0**	**14,250.7**
Probable	32,611.2	4,128.1	12,986.1	325.0	766.6	0.0	14,405.4
Total Proved Plus Probable	**92,336.1**	**11,708.8**	**38,188.6**	**3,729.4**	**10,053.2**	**0.0**	**28,656.2**

Future Net Revenue By Production Group (primary product) Before Tax, Discounted at 10%/year Forecast Prices and Costs As at 31 December 2017				
Reserves Category	**Production Group**	**Future Net Revenue ($000)**	**Unit Value**	**Unit**
Total Proved	Light and Medium Crude Oil	7,379	11.83	$/bbl
Proved + Probable	Light and Medium Crude Oil	13,170	14.50	$/bbl

PART 3: PRICING ASSUMPTIONS

Price and market forecasts prepared by Deloitte and used in the Reserve Report are summarized below. The prices are Deloitte's best estimate of future pricing, based on the many uncertainties that exist in the petroleum industry, and considering inflation forecasts and exchange rates.

Summary of Pricing and Inflation rate Assumptions Forecast Prices and Costs As at December 31 2017				
	Oil[1] US$/bbl	**Gas[2]** US$/Mcf	**Inflation rate** (%/year)	**Exchange Rate** (CDN/USD)
2018	$61.00	$8.30	0.0%	0.780
2019	$62.75	$8.05	2.0%	0.800
2020	$64.50	$7.90	2.0%	0.825
2021	$71.10	$7.95	2.0%	0.850
2022	$77.95	$8.10	2.0%	0.850
2023	$79.50	$8.30	2.0%	0.850
2024	$81.10	$8.45	2.0%	0.850
2025	$82.70	$8.60	2.0%	0.850
2026	$84.35	$8.80	2.0%	0.850
2027	$86.05	$8.95	2.0%	0.850
2028	$87.75	$9.15	2.0%	0.850
2029	$89.50	$9.35	2.0%	0.850
2030	$91.30	$9.50	2.0%	0.850
2031	$93.15	$9.70	2.0%	0.850
2032	$95.00	$9.90	2.0%	0.850
2033	$96.90	$10.10	2.0%	0.850
2034	$98.85	$10.30	2.0%	0.850
2035	$100.80	$10.50	2.0%	0.850
2036	$102.85	$10.70	2.0%	0.850
2037	$104.90	$10.95	2.0%	0.850

1. The Company has an agreement, effective 1 January 2018, with OMV New Zealand Limited (previously sold via Shell New Zealand (2011) Limited), pursuant to which OMV New Zealand Limited has agreed to purchase the company's crude oil on a Brent price basis. The values in the table are the Brent spot price forecasts from Deloitte. Based on the 2018 year sales contract fixed differential, the Company receives Brent pricing less C$2.90/bbl.

2. The gas price represented in the above table is referenced to UK NBP. Based on the previous year's sales, a differential of C$2.77/Mcf has been applied to Copper Moki and Waihapa as a reasonable expectation of what the Company will receive. Actual contracted gas sales price is NZ$4.50 /GJ i.e. ~C$3.90 /Mcf

The weighted average price received by the Company for oil in the year ended 31 December 2017 was C$65.04 per barrel.

PART 4: RECONCILIATION OF CHANGES IN RESERVES

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE						
Forecast Prices and Costs						
As at 31 December 2017						
	Light & Medium Oil			Conventional Gas		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf
31 December 2016	688.0	335.6	1,023.6	784.7	349.9	1,134.6
Production	-40.7	0.0	-40.7	-99.4	0.0	-99.4
Technical Revisions	-126.8	-85.9	-212.7	494.8	107.7	602.5
Extensions & Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquistions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-2.1	-1.5	-3.6	-2.0	-2.2	-4.2
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0
31 December 2017	**518.4**	**248.2**	**766.6**	**1,178.1**	**455.4**	**1,633.5**

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Proved and Probable Undeveloped Reserves
Forecast Prices and Costs
As at 31 December 2017

Reserves Category	Light & Medium Oil (Gross Mstb)		Natural Gas (Gross MMcf)		Barrels Oil Equivalent (Gross MBOE)	
	First Attributed	Aggregate	First Attributed	Aggregate	First Attributed	Aggregate
Proved Undeveloped						
31-Dec-15	-	128	-	90	-	143
31-Dec-16	-	125	-	88	-	140
31-Dec-17	-	129	-	116	-	149
Probable Undeveloped						
31-Dec-15	-	76	-	53	-	85
31-Dec-16	-	76	-	53	-	85
31-Dec-17	-	76	-	69	-	88

Proved and probable undeveloped reserves are generally those reserves related to well(s) awaiting the installation of an artificial lift system. Proved and probable undeveloped reserves have been assigned to a crestal well on the Waihapa Permit with a Tikorangi Formation target. The initial rate and profile of the well was estimated based on the performance of the other wells in the field.

The Company does not anticipate any unusually high development costs (noting the proposed use of ESPs) or operating costs related to development of the reserves, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

Estimated development costs deducted in the estimation of future net revenue attributable to the reserve categories noted below are as follows**:**

Estimated Future Development Costs
Forecast Prices and Costs
As at 31 December 2017
(in thousands of dollars)

Year	Proved Reserves	Proved plus Probable Reserves
2018	550	875
2019	789	789
2020	2,065	2,065
2021	-	-
2022	-	-
Total	**3,404**	**3,729**

The Company expects to fund the above development costs from a combination of existing working capital, cash flow from operations, and new debt or equity issues (if available on favourable terms). The cost of funding is not expected to have an effect on disclosed reserves or future net revenue, or to make the development of the properties uneconomic.

PART 6: OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The Company is focusing its activities in the Taranaki Basin on the west coast of the North Island of New Zealand. The Company has a 100% working interest in PMP 55491 ("**Copper Moki Permit**") and PEP 51150 ("**Eltham Permit**"); and a 50% interest in PML 38138 ("**Tariki Permit**"), PML 38140 ("**Waihapa Permit**") and PML 38141 ("**Ngaere Permit**") (collectively, the "**TWN Permits**"), and a 50% interest in the Waihapa Production Station, a full-cycle midstream processing facility. Collectively, these permits cover 70,350 acres on New Zealand's North Island.

Taranaki Basin

Copper Moki Permit

The Copper Moki PMP was granted on 28 July 2014 for an initial period of 8 years, and was split out of the Eltham Permit. The permit covers 943 acres (3.8km^2). The field comprises the Copper Moki-1 and Copper Moki-2 wells which produce from the Mt Messenger Formation (Late Miocene) using beam pump artificial lift, and associated surface production facilities. In November 2015 a water flood project was started in the Copper Moki-1 pool with the conversion of Waitapu-2 (previously shut in) from an oil producer to a water injection well. Copper Moki-3, a former high water-cut producer, is currently shut in. The wells have collectively produced a total of 422,164bbl from the Mt. Messenger Formation as at the end of March 2018, including oil produced during testing. The wells produce ~41^o degree API oil that is trucked to the Waihapa Production Station and then by pipeline to the Shell-operated Omata Tank Farm in New Plymouth and sold at Brent pricing.

Eltham Permit

The Eltham Permit was originally granted to the previous permit holder on 23 September 2008 for a period of five years. The Company was granted an extension for a second five-year term to 23 September 2018, and as part of that process relinquished 50% of the permit area. The total acreage of the current Eltham Permit, is 46,444 acres (187.9 km^2), of which approximately 6,046 acres (24.5 km^2) is offshore.

The Company drilled ten exploration wells on the Eltham Permit, four of which were successful producers and together with Copper Moki-4 were transferred to the Copper Moki PMP. The remaining exploration wells (see "Oil Wells" below) following evaluation, had been deemed unsuccessful/not commercial.

An Appraisal Extension Application has been lodged with a modified Work Program and over a greatly reduced area of approximately 898 acres (3.6km^2)of PEP 51150. The application area includes the 2012 Arakamu-2 discovery well, which produced oil from the Miocene Mt. Messenger Formation when tested in Q1-13. The Appraisal Extension is being assessed by the regulatory authority, New Zealand Petroleum and Minerals

TWN Permits and Waihapa Production Station ("TWN Assets")

The Company acquired the TWN Assets from Origin Energy on 28 October 2013. The assets include three PMLs (the Tariki Permit, Waihapa Permit and Ngaere Permit) ("TWN Permits") covering 22,962 onshore acres, as well as the Waihapa Production Station (WPS). The permits are contiguous with the northern border of the Eltham Permit. The Company holds a 50% interest in the TWN Assets (11,481 acres) together with L&M Energy ("**L&M**"), which acquired the other 50%. The Company and L&M have formed a 50/50 joint arrangement to explore, develop and operate the TWN Assets, with the Company acting as the operator. Permit areas were subject to minor revisions by the regulator in early 2018.

The TWN Permits offer multi-zone production and potential from the Urenui, Mt. Messenger, Moki, Tikorangi and Kapuni formations. Included with the TWN Permits were 16 established drill pads, most of which have oil and gas gathering pipelines in place to deliver production to the WPS. The acquisition also included 93 km^2 of 3D seismic data covering the south end of the TWN Permits and 585 km of 2D seismic data, along with log data from 27 previously drilled wells.

The WPS provides gathering, processing and sales infrastructure in the Taranaki Basin. WPS and its associated infrastructure includes a 45 mmcf/d gas processing, gas compression and liquefied petroleum gas extraction facility; a 51-km 8-inch gas sales pipeline from the WPS to the Stratford gas power generation plant then onwards to terminate at New Plymouth; 59 km of oil/gas mixed product pipelines including gas lift lines; a 25,000 bbl/d oil processing facility; a 49-km oil sales pipeline from the WPS to the Omata Tank Farm in New Plymouth capable of transporting up to 15,500 bbl/d; and an 18,000 bbl/d water processing and disposal system.

The Waihapa-Ngaere Tikorangi Limestone reservoir underlying the TWN Permits was discovered in 1988 and has produced more than 23 million barrels of oil to date through a succession of operators. Field oil production peaked at 15,046 bbl/day in 1994. Currently production is from six Tikorangi wells (four on continuous gas lift and two intermittently) and some minor production from two Mt Messenger wells.

The Company's near-term development plan for the TWN Assets is focussed on the Tikorangi Enhanced Oil Recovery project. This project is designed to mobilize stranded oil by reducing reservoir pressure through increasing total fluid production (reservoir voidage) to levels substantially greater than the natural aquifer can recharge. Stage-1 was implemented in Q3-16, with a new gas-lift valve system fitted to Waihapa-6. Oil cut rose resulting in a quadrupling of oil production from the well. Stage 2 was completed in Q1-17 with continuous gas-lift implemented in Ngaere-2 and -3, and an upgrade from 2 to 3 valve gaslift in Ngaere-1. The increase in water and gas throughput generated by this necessitated gas processing modifications and upgrades (Stage 3) prior to bringing further production volumes on line. This work was completed late in 2017 and planning for Stage 4, a high rate ESP installation in Ngaere-1 to achieve overall fluid offtake of 14,000 bfpd, is underway with the activity scheduled for mid-2018. A subsequent Stage 5 is envisaged to enable further oil production optimisation within the plant maximum capacity limit of 18,000 bbls per day of fluid (levels not seen since 1995), and would likely include a further ESP.

In the longer term, accessing the crestal area of the Waihapa-Ngaere Tikorangi structure is expected to be possible by a side-track from Waihapa-4 or from Waihapa-H1. However, it is also possible the reduction in reservoir pressure may create a secondary gas cap that displaces the same oil reserves downwards to become assessible from the existing wells. Reservoir studies to investigate this will be completed in 2018.

In addition, contingent resources and exploration targets in the Mt. Messenger, Tikorangi and Kapuni formations may be drilled in future appraisal and exploration programs in the TWN permits.

Oil Wells

The following table sets forth the number and status of oil wells in which the Company had a working interest as at 31 December 2017.

Well Name	Permit Name	Purpose	Producing		Non-Producing	
			Gross	Net	Gross	Net
Copper Moki-1	Copper Moki	Exploration	1	1	-	-
Copper Moki-2	Copper Moki	Exploration	1	1	-	-
Waitapu-2	Copper Moki	Exploration	-	-	1	1
Two Wells	Copper Moki	Exploration			2	2
Five wells	Eltham	Exploration	-	-	5	5
Toko-2B	Ngaere	Reactivated	1	0.5	-	-
Ngaere-3	Ngaere	Reactivated	1	0.5	-	-
Ngaere-2A	Ngaere	Reactivated	1	0.5	-	-
Ngaere-1	Ngaere	Reactivated	1	0.5	-	-
Waihapa-H1	Waihapa	Reactivated	1	0.5	-	-
Waihapa-6A	Waihapa	Reactivated	1	0.5	-	-
Seven other wells	Waihapa		-	-	7	3.5
Six other wells	Tariki		-	-	6	3
Total			**8**	**5**	**21**	**14.5**

All of the Company's currently producing wells are oil wells with associated gas. The Company has not specifically drilled natural gas wells but is actively studying reactivation of one such well in the Tariki Permit.

Permit Status: Renewals and Relinquishments

The table below outlines the current status and activity associated with NZEC's existing permits:

Permit	Permit name	Expiry	Activity
PML 38138	Tariki	20 July 2021	
PML 38140	Waihapa	19 June 2036	
PML 38141	Ngaere	19 June 2036	
PMP 55491	Copper Moki	27 July 2022	
PEP 51150	Eltham	22 September 2018	Appraisal Extension Application lodged with regulator with modified work program over a greatly reduced area

Tariki/Waihapa/Ngaere (TWN) PMLs

A small area (0.32km^2) of PML 38141 (Ngaere) was relinquished to remove an overlap with the adjacent permit PMP 52278 (Ahuroa), as agreed during the acquisition of the TWN assets.

Copper Moki:

There has been no activity specifically related to PMP conditions.

Eltham:

As stated above, an Appraisal Extension Application has been lodged with a modified Work Program and over a greatly reduced area of PEP 51150. If unsuccessful, a decision will be made on whether to drill an exploration well or surrender the permit.

Properties with No Attributed Reserves

The following table sets out the Company's interest in unproved properties as at 31 December 2017:

Permit	Location	Working Interest (%)	Gross Acres	Net Acres
Eltham Permit	Taranaki Basin, New Zealand	100	46,444	46,444
Tariki Permit	Taranaki Basin, New Zealand	50	3,566	1,783
Total			**50,010**	**48,227**

The Company estimates the following expenditures will be required in the five-year period commencing 1 January 2018 to complete the minimum work program and maintain the Company's Eltham Permit in good standing; otherwise, the PEP must be surrendered. The Company does not know whether its appraisal extension application (including a modified work program) will be approved, or what the scope of a future work programme may involve (and no estimate is provided). Expenditure for 2018 continues to assume the existing commitment to drilling an exploration well. No estimate is made post 2018 pending the appraisal application.

Permit	2018 ($)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	Total ($)
Eltham Permit	3,432,000	N/A	N/A	N/A	N/A	3,432,000

For properties with no attributed reserves, the Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Forward Contracts

The Company does not have any forward contracts under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas.

Additional Information Concerning Abandonment and Reclamation Costs

Management estimates abandonment and reclamation costs based on past experience and analysis of industry peers.

Copper Moki Permit

As at 31 December 2017, management expected to incur abandonment and reclamation costs on five net wells located on the Copper Moki Permit. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $1.8 million (estimated present value of $1.2 million using a 10% discount rate). Within the next three financial years, the Company estimates abandonment and reclamation costs, net of estimated salvage value, will total $Nil (estimated present value of $Nil using a 10% discount rate).

Of the abandonment and reclamation costs disclosed above, $476,000 was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

Eltham Permit

As at 31 December 2017, management expected to incur abandonment and reclamation costs on four net wells located on the Eltham Permit. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $717,000 (estimated present value of $683,000 using a 10% discount rate). The Company expects this will be incurred within the next two financial years.

Of the abandonment and reclamation costs disclosed above, $725,000 was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

TWN Permits and Waihapa Production Station

As at 31 December 2017, preliminary estimates carried out by management suggest the Company's 50% interest in abandonment and reclamation costs related to 19 existing wells (9.5 net wells) on the TWN Permits is approximately $6.0 million (estimated present value of $1.6 million using a 10% discount rate). In addition, the Company's interest in estimated reclamation costs for the Waihapa Production Station is expected to be approximately $8.4 million (estimated present value of $1.4 million using a 10% discount rate).

Of the abandonment and reclamation costs disclosed above, $2.5 million was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

Ranui Permit

In December 2013 the Company surrendered the Ranui Permit (PEP 38342), located in the East Coast Basin. As at 31 December 2017, management expected to incur abandonment and reclamation costs on the Ranui Permit related to one well. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $223,000 which is expected to be incurred within the next three financial years.

Tax Horizon

Regulations in New Zealand allow companies with common shareholdings to share losses and tax deductions across those companies, provided certain requirements are satisfied. These requirements are complex and include a requirement for 49% of continuity of ownership in the loss company, while 66% commonality of ownership has to exist in the group companies. Depending on the Company's ability to maintain shareholder continuity, as well as on the levels of production, commodity prices and capital expenditures, management currently does not expect to pay any income tax arising from cash flows on either the Copper Moki Permit or the TWN Permits.

Costs Incurred

The following table summarizes the estimated costs incurred for each of the following categories in the most recently completed fiscal year:

Expenditure ($)	Twelve months ended 31 December 2017
Property acquisition costs (proved properties)	-
Property acquisition costs (unproved properties)	-
Exploration costs (1)	-
Development costs (2)	62,700
Total	**62,700**

Notes:
(1) Includes geological and geophysical capital expenditures and drilling costs for exploration wells.
(2) Includes development drilling, completion and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The Company did not drill any exploratory oil wells in the most recently completed fiscal year. The Company's most important current and likely exploration and development activities on its properties in 2018 are as follows:

TWN Permits and Waihapa Production Station

The Company continues to focus its near-term development efforts on the TWN Permits. The Company's objective is to increase production and cash flow while reducing expenses, and believes opportunities exist on the TWN Permits to achieve this objective. More specifically, the enhanced oil recovery project (described above) will be progressed. The proposed work in 2018 is the implementation of Stage 4 - installing an electric submersible pump (ESP) in Ngaere-1 to achieve overall fluid offtake of ~14,000 bfpd.

Copper Moki Permit

The Company will continue to operate its two producing wells with pump-jack/rod pumps. Workover operations to change the downhole rod pump in Copper Moki-1 were completed in mid-February 2018, with subsequent production results above expectation. By end February 2018, Copper Moki-1 was producing at ~100 bopd and 115 bwpd. In early March 2018, following pump-jack servicing, the stroke rate was increased by 15%. This resulted in a further increase in production volumes - through the balance of March 2018 Copper Moki-1 produced at an average of 160 bopd, with a decreasing water cut.

Given the ongoing success of the Copper Moki-1 pool water-flood studies are progressing to investigate water-flood support of the Copper Moki-2 producing oil pool.

Eltham Permit

As stated above, an Appraisal Extension Application has been lodged with a modified Work Program and over a greatly reduced area of PEP 51150. If unsuccessful, a decision will be made on whether to drill an exploration well or surrender the permit.

Production Estimates

The following table sets out the volumes of production estimated for the year ending 31 December 2018 from the Copper Moki, Waihapa and Ngaere permits, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained earlier in Part 2 of this statement of reserves data.

Category	**Light and Medium Oil (bbl/d)**	**Natural Gas (Mcf/d)**	**Barrels of Oil Equivalent (BOE/d)**
Copper Moki			
Gross Proved Production	51.7	31.1	56.9
Gross Probable Production	13.7	6.7	14.8
Waihapa/Ngaere			
Gross Proved Production	59.5	210.0	94.5
Gross Probable Production	0.7	2.6	1.1

Production History

The Company started producing from its wells on the Copper Moki Permit as follows: Copper Moki-1, December 2011; Copper Moki-2, April 2012; Copper Moki-3, June 2012; Waitapu-2, December 2012. The Company started producing from its six reactivated wells on the TWN Permits in November 2013. The following table summarizes certain information regarding estimated production, product prices received, estimated royalties incurred, estimated operating expenses and the estimated resulting netback for the year ended 31 December 2017:

	Quarter Ended				Year Ended
	31 Mar 2017	30 Jun 2017	30 Sep 2017	31 Dec 2017	31 Dec 2017
Average Daily Production (NZEC share)					
Light and medium oil (bbl/d)	141	120	99	88	112
Gas (Mcf/d)	-	-	-	-	-
Average Prices Received					
Light and medium oil ($/bbl)	66.70	61.54	60.24	74.45	65.04
Gas ($/Mcf)	-	-	-	-	-
Royalties Paid (NZEC share)					
Light and medium oil ($/bbl)	5.80	5.74	1.65	7.33	5.02
Gas ($/Mcf)	-	-	-	-	-
Production Costs ($/bbl) (NZEC share)	25.62	32.99	12.44	40.39	27.32
Field Netback Received ($/bbl)	35.27	22.81	46.15	26.74	32.70

The Company's working interest share of production volumes, in total and for each important field, for the year ended 31 December 2017, are set out in the following table:

Production Volume	**Light and Medium Oil (bbl)**	**Natural Gas (Mcf)**
Copper Moki Permit	22,006	23,388
Waihapa and Ngaere Permits	18,647	94,863
Total	**40,653**	**118,251**