GREENFIELDS PETROLEUM CORPORATION

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE DATE: DECEMBER 31, 2017

FEBRUARY 8, 2018

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbl/d	barrels per day	MMcf	million cubic feet
Mbbl	thousands of barrels	Bcf	billion cubic feet
boe	barrels of oil equivalent, including barrels of crude oil and natural gas, unless otherwise indicated	Mcf/d	thousand cubic feet per day
boe/d	barrels of oil equivalent per day		
Mboe	thousand boe		
NGL	natural gas liquids		
MMBtu	million British thermal units		
API	American Petroleum Institute		

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.317
Cubic metres	Cubic feet	35.315
Bbls oil	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

EXCHANGE RATES

Except as otherwise indicated, all dollar amounts referenced in this Statement of Reserves Data and Other Oil and Gas Information are expressed in United States dollars. The following table sets forth: (i) the rates of exchange for United States dollars expressed in Canadian dollars, in effect at the end of each of the periods indicated; and (ii) the average of exchange rates during such periods, in each case based on the noon rate reported by the Bank of Canada.

	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Rate at end of period	1.2545	1.3427	1.3840
Average noon spot rate during period	1.2986	1.3248	1.2787

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

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

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

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

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

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

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

The following terms, used in the preparation of the GLJ Report and this document, have the following meanings:

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir.

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

“**crude oil**” or “**oil**” means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

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

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

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

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

D) provide improved recovery systems.

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

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

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

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

C) dry hole contributions and bottom hole contributions;

D) costs of drilling and equipping exploratory wells; and

E) costs of drilling exploratory type stratigraphic test wells.

“**exploratory well**” means a well that is not a development well, a service well or a stratigraphic test well.

“**field**” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “**structural feature**” and “**stratigraphic condition**” are intended to denote localized geological features, in contrast to broader terms such as “**basin**”, “**trend**”, “**province**”, “**play**” or “**area of interest**”.

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

“**gross lease**” means:

A) in relation to the Corporation’s interest in production or reserves, its “company gross lease reserves”, are it’s working interest (operating or non-operating) marketable share, before deduction of royalties and without including any royalty interests of the Corporation;

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

C) in relation to properties, the total area of properties in which the Corporation has an interest.

“**light crude oil**” means crude oil with a relative density greater than 31.1 degrees API gravity.

“**medium crude oil**” means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

“**natural gas**” means a naturally occurring mixture of hydrocarbon gases and other gases.

“**natural gas liquids**” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

“**net**” means:

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

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

C) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“**non-associated gas**” means an accumulation of natural gas in a reservoir where there is no crude oil.

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

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

“**property**” includes:

A) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

B) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

C) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

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

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

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

C) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“**proved property**” means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation, or injection for combustion.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "**exploratory type**" if not drilled into a proved property; or (b) "**development type**", if drilled into a proved property. Development type stratigraphic wells are also referred to as "**evaluation wells**".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

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

ADDITIONAL DEFINITIONS

Wherever used in this Statement of Reserves Data and other Oil and Gas Information, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

"**Azerbaijan**" means the Republic of Azerbaijan;

"**Bahar Energy**" means Bahar Energy Limited, a company incorporated in the Jebel Ali Free Zone, Dubai, UAE, a 100% wholly owned subsidiary of the Corporation;

"**Bahar Gas Field**" means the gas field located in the offshore Caspian Sea area of Azerbaijan that is the subject of the ERDPSA and contains approximately 204 offshore wells;

"**Contractor Parties**" means, collectively, SOA and Bahar Energy as contractors under the ERDPSA;

"**Corporation**" or "**GPC**" means Greenfields Petroleum Corporation;

"**ERDPSA**" means the exploration, rehabilitation, development and production sharing agreement, which includes the Bahar Gas Field and the Gum Deniz Oil Field, dated December 22, 2009, among Bahar Energy, SOCAR and SOA;

"**Exploration Area**" means the contract exploration area referred to as the Bahar-2 area as specified in the ERDPSA;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent qualified reserves evaluators;

"**GLJ Report**" means the report of GLJ dated February 2, 2018 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2017;

"**Gum Deniz Oil Field**" means the oil field located in the offshore Caspian Sea area of Azerbaijan that is the subject of the ERDPSA;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Rehabilitation Area**" means the rehabilitation area in the Gum Deniz Oil Field and the Bahar Gas Field as specified in the ERDPSA;

"**SOA**" means SOCAR Oil Affiliate;

"**SOCAR**" means the State Oil Company of the Republic of Azerbaijan;

"**UAE**" means the United Arab Emirates; and

"**U.S.A.**" or "**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any state of the United States of America and the District of Columbia.

DISCLOSURE OF RESERVES DATA

The GLJ Report was prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time (the "**COGE Handbook**"). The GLJ Report estimates the reserves of Bahar Energy as of December 31, 2017 (which includes the wells, lands, reserves, facilities, equipment and other assets including the Bahar Gas Field and the Gum Deniz Oil Field) which it holds pursuant to the ERDPSA. The estimated reserves included in the GLJ Report include all of Bahar Energy's interest in the ERDPSA. The Corporation owns a 100% interest in Bahar Energy who in turn owns an 80% participating interest in the ERDPSA, and, as such, the reserve estimates and other data provided which are derived from the GLJ Report reflect the Corporation's 100% interest in Bahar Energy.

Information presented herein is presented in accordance with the requirements of Form 51-101F1.

The tables below are a summary of the oil, NGLs and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on constant and forecast price and cost assumptions. The tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

Boe's may be misleading particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The GLJ Report is based on certain factual data supplied by the Corporation and GLJ's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Corporation for the year ended December 31, 2017 include a full year of operating data on the properties of the Corporation.

Summary of Oil and Natural Gas Reserves as of December 31, 2017 – Forecast Prices and Costs

	Gross Lease Reserves [1]			Net Reserves [2]		
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Conventional Natural Gas**	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Conventional Natural Gas**
	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mmcf
Proved						
Developed Producing	152	13	4,295	132	11	3,720
Developed Non-Producing	2,940	2,141	202,376	2,047	1,488	140,304
Undeveloped	9,809	544	29,607	6,404	302	14,267
Total Proved	**12,901**	**2,698**	**236,278**	**8,583**	**1,801**	**158,292**
Probable	14,139	1,992	159,673	6,157	773	56,857
Total Proved plus Probable	**27,041**	**4,690**	**395,951**	**14,740**	**2,573**	**215,149**

Notes:

(1) "**Gross Lease Reserves**" are the 8/8th's, marketable reservoir volumes.

(2) "**Net Reserves**" are the Corporation's 100% share of Bahar Energy's reserves pursuant to the ERDPSA which are net of the interest of SOA and other deductions consisting of operating and capital cost recovery as well as future contributions to the ERDPSA Abandonment Fund factored in the determination of the Corporations' share of volumes.

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs

	Discounted At [1]				
	0%	**5%**	**10%**	**15%**	**20%**
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	5,834	5,694	5,563	5,440	5,326
Developed Non-Producing	275,355	210,458	165,892	134,224	111,040
Undeveloped	190,099	130,618	89,572	60,608	39,751
Total Proved	**471,288**	**346,769**	**261,027**	**200,272**	**156,117**
Probable	437,485	341,844	276,600	229,320	193,561
Total Proved plus Probable	**908,773**	**688,614**	**537,626**	**429,593**	**349,678**

Note:

(1) The amounts included herein are the same on a before and after tax basis because, pursuant to the ERDPSA, an income tax equivalent to 20% of the profit is paid by SOCAR on behalf of the Contractor Parties to the government of Azerbaijan. Any US taxes will be partially offset by the tax credits. In addition, the Contractor Parties are exempt from all other taxes, duties and royalties in Azerbaijan, other than certain customs fees, personal income tax and contributions to the state social insurance funds of Azerbaijan.

	Unit Value before Income Tax Discounted at 10% ($/boe)
Proved	
Developed Producing	7.29
Developed Non-Producing	6.16
Undeveloped	9.86
Total Proved	**7.10**
Probable	16.86
Total Proved plus Probable	**10.11**

Additional Information Concerning Future Net Revenue – Undiscounted Forecast Prices and Costs [1][2]

	Revenue	Operating Costs	Development Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Total Proved	1,101,709	419,632	210,789	471,288	-	**471,288**
Total Proved plus Probable	1,701,141	518,016	274,352	908,773	-	**908,773**

Notes:

(1) No column concerning royalties has been provided as Bahar Energy is not subject to royalties.

(2) No column concerning abandonment and reclamation costs has been provided. Bahar Energy has a future obligation to make quarterly cash payments into an abandonment fund beginning July 1, 2021 based on calculations agreed with SOCAR. The payment obligation is limited by the ERDPSA and the amounts funded are recognized as Operating Costs and reimbursed to Bahar Energy through cost recovery in the period in which the obligation is paid.

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (Discounted at 10%/Year)	Unit Value Before Income Taxes (Discounted at 10%/Year)
	(M$)	($/boe)
Proved		
Light and Medium Crude Oil [1]	112,315	13.63
Conventional Natural Gas [2]	148,711	5.21
Proved plus Probable		
Light and Medium Crude Oil [1]	266,118	18.78
Conventional Natural Gas [2]	271,508	6.96

Notes:

(1) Including associated by-products.

(2) Including associated by-products.

Pricing Assumptions - Forecast Prices and Costs

GLJ used the following pricing and inflation rate assumptions as of December 31, 2017 in its evaluation contained in the GLJ Report in estimating GPC's reserves data using forecast prices and costs.

	Brent Oil Price [1]	Net Realized Oil Price [2]	Natural Gas Contract Price	Net Realized NGL Price [2]	% Cost Escalation Operating Expenses	Inflation rate
	($/bbl)	($/bbl)	($/MMBTU)	($/bbl)	(%)	(%)
Forecast						
2018	65.50	58.57	2.69	58.57	0.0	0.0
2019	63.50	56.63	2.69	56.63	2.0	2.0
2020	63.00	56.10	2.69	56.10	2.0	2.0
2021	66.00	58.86	2.69	58.86	2.0	2.0
2022	69.00	61.61	2.69	61.61	2.0	2.0
2023	72.00	64.37	2.69	64.37	2.0	2.0
2024	75.00	67.12	2.69	67.12	2.0	2.0
2025	78.00	69.87	2.69	69.88	2.0	2.0
2026	80.33	72.00	2.69	72.00	2.0	2.0
2027	81.88	73.38	2.69	73.38	2.0	2.0
2028+	+2%/yr [3]	+2%/yr [3]	2.69	+2%/yr [3]	2.0	2.0

Notes:

(1) Per GLJ Petroleum Consultants Crude Oil Price Forecast effective January 1, 2018.

(2) Net Realized Oil Prices are calculated at approximately 94% of GLJ forecast Brent Crude Price less $3.00/bbl for transportation and marketing costs.

(3) Escalation rates are based on the Society of Petroleum Evaluation Engineers annual survey of projected expenses and costs.

The weighted average net realized sales prices for the year-ended December 31, 2017 were $3.02/Mcf for natural gas and $47.40/bbl (Oil price subject to year-end 2017 financial closing adjustments as December 2017 oil liftings have not been priced at the date of this report).

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

The following table sets forth reconciliation of GPC's gross proved reserves, gross probable reserves and gross proved plus probable reserves at December 31, 2017, against such reserves as at December 31, 2016, based on forecast price and cost assumptions.

Azerbaijan

Proved	**Light and Medium Crude Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2016	**5,169**	**108,805**	**1,106**	**24,409**
Technical Revisions	3,626	43,678	441	11,347
Infill Drilling	-	11,875	270	2,249
Production	(212)	(6,066)	(16)	(1,239)
Balance at December 31, 2017	**8,583**	**158,292**	**1,801**	**36,766**

Probable	**Light and Medium Crude Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2016	**5,063**	**59,576**	**615**	**15,607**
Technical Revisions	1,094	(19,742)	(228)	(2,424)
Infill Drilling	-	17,023	386	3,223
Production	-	-	-	-
Balance at December 31, 2017	**6,157**	**56,857**	**773**	**16,406**

Proved plus Probable	**Light and Medium Crude Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2016	**10,232**	**168,381**	**1,720**	**40,016**
Technical Revisions	4,720	23,936	214	8,923
Infill Drilling	-	28,898	655	5,472
Production	(212)	(6,066)	(16)	(1,239)
Balance at December 31, 2017	**14,740**	**215,149**	**2,573**	**53,171**

The changes in balances between year end 2016 and year end 2017 were the result of ongoing technical assessments undertaken by the operator BEOC for the past 18 months. The assessments supported an increase in Natural Gas and Natural Gas Liquids which led to Technical Revisions from additional gas recompletions identified in the Bahar Gas Field and Infill Drilling in the NKP gas reservoir in the Bahar Gas Field. The assessments also supported an increase in Medium and Light Crude Oil which led to Technical Revisions from identifying additional oil recompletions and the implementation of Waterfloods in the Gum Deniz Oil Field.

Undeveloped Reserves

The following discussion generally describes the basis on which GPC attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves. Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook.

The majority of these reserves are planned to be on stream within a three-years time frame. In some cases, it will take longer than three years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to weather conditions and regulatory approvals).

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied in, wells drilled near the end of the fiscal year or wells further away from GPC gathering systems. In addition, such reserves may relate to planned infill drilling locations.

The table sets forth the proved undeveloped reserves volumes that were first attributed in each of the three most recent financial years.

	Company Gross Reserves First Attributed by Year-end			
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Barrels of Oil Equivalent**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)
2015	-	-	-	-
2016	-	-	-	-
2017	4,598	295	13,433	7,132

Probable Undeveloped

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

The table sets forth the probable undeveloped reserves volumes that were first attributed in attributed in each of the three most recent financial years.

	Company Gross Reserves First Attributed by Year-end			
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Barrels of Oil Equivalent**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)
2015	206	-	-	206
2016	-	-	-	-
2017	4,012	23	-	4,035

Significant Factors or Uncertainties Affecting Reserve Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. GPC reserves are evaluated by GLJ, an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecasted prices and costs only) and proved plus probable reserves (using forecast prices and costs only).

Azerbaijan

	Development Costs	
	Proved Reserves	**Proved plus Probable Reserves**
	(M$)	(M$)
2018	24,076	24,612
2019	101,131	110,164
2020	40,780	60,547
2021	17,327	45,768
2022	7,958	7,525
Remaining Years	19,517	25,736
Total Undiscounted	**210,789**	**274,352**

GPC typically utilizes three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favorable terms. The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and may reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make the development of a property uneconomic.

Oil and Gas Properties

The following is a description of the oil and gas properties in which the Corporation has an indirect interest through Bahar Energy's 80% participating interest in the ERDPSA.

The properties associated with the ERDPSA are related to oil and gas production in the shallow waters of the Caspian Sea south of the Absheron Peninsula located about 15 kilometers from downtown Baku, Azerbaijan. The facilities include 146 offshore platforms, multiple pipelines and 9.6 kilometers of steel causeways with well pads from an offshore island south into the shallow waters of the Caspian Sea. One main collector pipeline carries fluids produced from the Gum Deniz Oil Field across Gum Island to separation facilities on the mainland. Four pipelines transport gas and liquids from the Bahar Gas Field directly to gas separation facilities located on the mainland.

Gum Island, lying 2.5 kilometers offshore, is connected to the mainland by a stone and paved causeway. This island houses the main operating offices, warehousing and equipment storage, and a marine base for offshore operations. The main fluid and gas handling facilities including oil and gas storage, separation, compression and metering stations are all located onshore on the mainland, and are therefore not subject to the offshore operating environment.

Gas and liquids production coming ashore from Bahar gas field traverses through a slug catcher and three-phase separation and dehydration facilities. The dry gas is then sent to a low pressure compressor station for onward shipment through sales meters and into the SOCAR pipeline system for delivery to the local gas market.

Oil, water and associated gas production from the Gum Deniz Oil Field are collected offshore and delivered through a main collector pipeline across the Island and the stone causeway to the mainland where gas, oil and water are separated through a series of separation facilities. Oil is stored in six 2000 cubic meter tanks prior to shipment to the SOCAR tank farm at Surakhany. Water is cleaned to discharge specification. Associated gas is used as fuel or is sent to one of two high pressure compressor stations for delivery to a line that carries it back to Gum Deniz Oil Field where it is used for gas lift in producing wells.

Many of the producing and planned well re-entries have wellheads and platforms, which have been severely neglected over the last 15 to 20 years and require maintenance, cleanup and repair. Much of this infrastructure has not seen maintenance or repair expenditure after investment was diverted to Western Siberia before the collapse of the Soviet Union.

The Exploration Area had a three-year exploration phase with a one-year extension available, during which Bahar Energy was required to shoot 60 kilometers of 3D seismic and drill one well in order to maintain its rights in the Exploration Area. The Exploration Area may be relinquished if non-commercial quantities of hydrocarbons are not discovered.

Currently there are 34 producing wells, 24 of which are in the Gum Deniz Oil Field and produce oil with associated gas and 10 of which are located in the Bahar Gas Field and produce natural gas with condensate. For the Bahar Energy's ownership only, another 222 wells are shut in. No wells have been plugged and abandoned.

Bahar Gas Field, Republic of Azerbaijan

Bahar Gas Field lies in the Caspian Sea about 25 kilometers off the coast of the Apsheron peninsula. It was developed from 76 offshore platforms. A central processing and metering platform gathers the gas and liquids for onward transport via four 12-inch pipelines to the shore-based gas and liquid handling facilities. Each wellhead platform has a small separate adjacent platform extension for housing operations personnel. All record keeping and field operations are conducted offshore and personnel are transferred by crew boat on various rotational schedules. The platforms are built on 24 to 30 pilings each in an average water depth of 20 meters. BEOC has rehabilitated the platforms and infrastructure necessary for production operations. Many of the other platforms and infrastructure will be usable after refurbishment is undertaken. Workers and equipment is brought to and from the platforms by crew and crane vessels. Crew vessels rely on boat docks and gangways for platform access, so access is weather dependent. Roughly 200 wells were drilled in the Bahar Gas Field of which 101 wells have been retained. Currently 10 wells are producing natural gas and condensate. The platforms have testing facilities, but production is then recombined for flow to the facilities onshore.

Gum Deniz Oil Field, Republic of Azerbaijan

The Gum Deniz Oil Field is located just south of the Apsheron peninsula between Gum Island and the Bahar Gas Field. The field begins on Gum Island, which is 2.5 kilometers from the mainland, and progresses southward into the Caspian Sea. Much of the field was developed from platforms connected to a 9.6 kilometers steel causeway. About 70 platforms were constructed to develop the field. The causeways allow small packages of drilling and workover equipment to be moved onto the wellhead platforms and it is easy for motorized vehicles to drive out and inspect the operations. Oil, water and gas are delivered via a main collector pipeline along the causeway, across the Island and on to the onshore treatment facilities. There are currently 24 wells producing of the 155 retained oil wells. The wells are currently producing via electrical submersible pumps or gas lift using compressed gas from the onshore gas compression facilities.

Similar to the Bahar Gas Field, many of the platforms and facilities that service the Gum Deniz Oil Field are in poor condition due to the minimal capital investments since the separation of the former Soviet Union. The wells, platforms, causeway and facilities that are necessary for production have been refurbished and are suitable and safe for oil and gas operations. This has allowed for more workovers and recompletions to be undertaken. Other platforms can be refurbished as needed to enable additional workovers or drilling.

Drilling Activity and Location of Production and Wells

Oil and Gas Wells

The following table summarizes GPC's gross and net interests through Bahar Energy as at December 31, 2017 in field wells that are producing and non-producing.

	Producing Wells				**Non-Producing Wells (3)**			
	Oil		**Natural Gas**		**Oil**		**Natural Gas**	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Azerbaijan	24	19.2	10	8	131	104.8	91	72.8

Notes:

(1) "**Gross**" refers to all wells in which GPC has either a working interest or a royalty interest.

(2) "**Net**" refers to the aggregate of the percentage working interests of GPC in the gross wells before deduction of royalties.

(3) "**Non-Producing wells**" refers to wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons. Non-Producing wells in which GPC has an interest are located no further than 10 kilometers from existing pipelines.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which GPC has an interest through Bahar Energy and also the number of net acres for which GPC's has rights to explore, develop or exploit the potential energy resources of the Exploration Area under the ERDPSA. The initial three-year exploration term from October 1, 2010 through September 30, 2013 has expired, however SOCAR has not terminated the rights to this acreage and Bahar Energy continues to assess the economic merits of drilling an exploration well based on the results of the analysis of the 3D seismic data and further subsurface studies. Prior to any proposed drilling an exploration well, an extension to the exploration period will be obtained from SOCAR.

	Gross Undeveloped Acres (1)	**Net Undeveloped Acres (1)**	**Net Acres Expiring Within One Year**
Azerbaijan Exploration Area (2)	26,676	26,676	-

Notes:

(1) Unproved Properties have no attributed reserves as of December 31, 2017. Undeveloped acreage within properties where reserves have been booked as of December 31, 2017 has not been included.

(2) In the Exploration Area pursuant to the ERDPSA, Bahar Energy is required to acquire a minimum of 60 square kilometers of 3D seismic and potentially drill at least one exploration well should a viable drilling prospect be identified. The obligation to acquire the 3D seismic has been met and potential drilling prospects continue to be evaluated.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Development of the Corporation's properties with no attributed reserves are subject to capital allocation constraints and influenced by many factors and uncertainties, including market prices of oil and natural gas, results of exploration and development activities in the Exploration Area, and the timing and anticipated benefits of infrastructure construction and rehabilitation activities.

Forward Contracts

The Corporation is not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas. The Corporation's primary revenues are from oil and gas sales produced in Azerbaijan under the ERDPSA. Oil is sold through SOCAR and priced, on a quality differential basis, to the U.S. dollar based Intercontinental Exchange ("**ICE**") Brent oil price at sales date. Beginning April 1, 2017, under an amended Gas

Sales Agreement that extends the contract for five years, natural gas will be sold to SOCAR at a fixed price of $2.69/Mcf under the amended Gas Sales Agreement, which is a decrease from the previous sales price of $3.96/Mcf. At December 31, 2017, the Corporation had no outstanding financial instruments, or financial derivatives contracts subject to commodity price risk.

Additional Information Concerning Abandonment Costs

In an effort to finance abandonment of all fixed assets employed in the ERDPSA by the Contractor Parties (Bahar Energy and SOA), the parties will open a joint escrow account at a bank of good international repute to be agreed between SOCAR and the Contractor Parties. This account will be known as the "**Abandonment Fund**" and will be administered by the operating company in coordination with SOCAR for maximum value. All monies allocated to the Abandonment Fund will be recoverable as operating costs. In no event will the Abandonment Fund exceed 15% of all capital costs incurred in the Exploration Area and the Rehabilitation Area, respectively.

The "Protocol on the Abandonment of Fixed Assets" for the Rehabilitation Area was executed with SOCAR on December 12, 2012. The provisions of the protocol specify that an abandonment plan with cost estimate must be completed no later than one year prior to the tenth calendar year following the effective date of October 1, 2010 with funding of the Abandonment Fund to commence July 1, 2021. The calculation of the quarterly amounts to be funded into the Abandonment Fund are based on the estimated abandonment costs (limited to 15% of cumulative capital costs), cumulative production from the date the Abandonment Fund is established and estimated remaining recoverable reserves.

For the Exploration Area, no abandonment obligation exists until there has been a commercial discovery and cumulative production from this contract area reaches 50% of the recoverable reserves identified in the development plan. At that time, the same funding procedures noted for the Rehabilitation Area will be employed. There is no abandonment obligation in the event that Bahar Energy terminates the ERDPSA or if the exploration term for the Contract Exploration Area is allowed to expire.

As a result, all costs of abandonment that the Contractor Parties undertake during the term of the ERDPSA will be cost recovered under the ERDPSA. At the end of the term of the ERDPSA, all remaining abandonment obligations are transferred to SOCAR.

The Corporation cannot estimate Bahar Energy's asset retirement obligations at present, and the Corporation does not expect Bahar Energy to incur significant expenditures with respect to asset retirement obligations over the next three years. The Corporation will be liable for its share of ongoing environmental obligations. Ongoing environmental obligations are expected to be funded out of cash flow.

Tax Horizon

The Corporation does not believe that it will incur any income taxes in the intermediate term. In the United States, the Corporation expects to have operating loss carry-forward and foreign tax credits to offset the taxable income during the intermediate term. In accordance with the ERDPSA, SOCAR pays income taxes applicable to the ERDPSA on behalf of Bahar Energy to the government of Azerbaijan. As a result of these factors, the Corporation does not expect to have generated taxable income in the United States for at least four to six years, if not longer.

The Corporation does not have any income generating assets in Canada.

Costs Incurred

The following table summarizes the Corporation's gross property acquisition costs, exploration costs and development costs for the year ended December 31, 2017.

Azerbaijan

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs [1]
Total (M$)	-	-	-	24,631

Note:
(1) The above indicated amount of Development Costs may be adjusted for year-end 2017 financial closing due April 30, 2018.

Exploration and Development Activities

The Corporation did not complete, or participate in the completion of, any exploration or development wells during the year ended December 31, 2017.

For the remainder of 2018, the Corporation will focus on platform refurbishment and upgrades in the Bahar Gas Field, oil and gas processing facility upgrades, adding an additional gas lift line in the oil field, upgrades fire, support infrastructure and safety monitoring systems, reservoir engineering studies in Gum Deniz Oil and Bahar Gas Fields following the completion of static models in both fields, and the workover and recompletion of 37 wells in Gum Deniz and Bahar fields.

Production Estimates

The following table summarizes the Corporation's 100% share of Bahar Energy's estimated future annual production volumes for the assets evaluated in the GLJ Report for the 12 months beginning January 1, 2018 and ending December 31, 2018 for each product type.

Field	Light and Medium Crude Oil and NGL	Conventional Natural Gas	Barrels of Oil Equivalent	%
	(bbl/d)	(Mcf/d)	(boe/d)	
Bahar, Azerbaijan	165	20,591	3,597	81.9
Gum Deniz, Azerbaijan	792	-	792	18.1
Total Proved	**957**	**20,591**	**4,389**	**100**
Bahar, Azerbaijan	53	3,860	697	76.5
Gum Deniz, Azerbaijan	214	-	214	23.5
Total Probable	**267**	**3,860**	**911**	**100**

Production History

The following table on a quarterly basis for the year ended December 31, 2017, discloses the Corporation's share of average daily entitlement volume less compensatory petroleum volumes delivered to SOCAR.

	Three Months Ended			
	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Light and Medium Crude Oil (bbl/d) [1]	709	674	573	550
Conventional Natural Gas (Mcf/d)	17,296	17,120	15,902	16,214
Natural Gas Liquids (bbl/d)	-	-	-	-
Total (boe/d)	**3,591**	**3,527**	**3,223**	**3,252**

Note:
(1) Includes Natural Gas Liquids which volumes are commingled with the crude oil liftings delivered to SOCAR.

Prices Received, Production Costs, Marketing Cost, and Netback

The following table discloses on a quarterly basis for the year ended December 31, 2017, the Corporation's revenue share of entitlement production after deducting for production costs and marketing costs, such as transportation and storage charges, custom and bank fees and selling expenses.

	Three Months Ended			
($ per bbl)	**March 31, 2017**	**June 30, 2017**	**Sept. 30, 2017**	**Dec. 31, 2017** (1)
Prices Received (2)	48.20	42.89	48.46	54.54
Production Costs	13.90	13.99	14.03	13.80
Marketing Costs	0.50	0.46	0.50	0.50
Netback	**33.80**	**28.44**	**33.93**	**40.24**

	Three Months Ended			
($ per Mcf)	**March 31, 2017**	**June 30, 2017**	**Sept. 30, 2017**	**Dec. 31, 2017** (1)
Prices Received	3.96	2.69	2.69	2.69
Production Costs	2.32	2.33	2.34	2.30
Marketing Costs	-	-	-	-
Netback	**1.64**	**0.36**	**0.35**	**0.39**

	Three Months Ended			
($ per boe)	**March 31, 2017**	**June 30, 2017**	**Sept. 30, 2017**	**Dec. 31, 2017 (1)**
Prices Received (2)	28.58	21.25	21.89	22.86
Production Costs	13.90	13.99	14.03	13.80
Marketing Costs	0.50	0.46	0.50	0.50
Netback	**14.18**	**6.80**	**7.36**	**8.56**

Note:
(1) Prices Received, Production and Marketing Costs may be subject to year-end 2017 financial closing adjustments.
(2) Light and Medium Crude Oil includes Natural Gas Liquids which volumes are commingled with crude oil liftings delivered to SOCAR.

Average Production Volume

The following table discloses the Corporation's average daily production for the year ended December 31, 2017.

Field	**Light and Medium Crude Oil** (2)	**Conventional Natural Gas**	**Natural Gas Liquids** (2)	**Barrels of Oil Equivalent** (2)
	(bbl/d)	(Mcf/d)	(bbl/d)	(boe/d)
Bahar, Azerbaijan	-	16,619	-	2,770
Gum Deniz, Azerbaijan	626 (1)	-	-	626 (1)
Total	**626**	**16,619**	**-**	**3,396**

Note:
(1) Includes Natural Gas Liquids produced from the Bahar Gas Field which volumes are commingled and processed at Gum Deniz Oil Field facilities.
(2) Production volumes may be subject to year-end 2017 financial closing adjustments.

Forms 51-101F2 and 51-101F3

Form 51-101F2, Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Form 51-101F3, Report of Management and Directors on Oil and Gas Disclosure for the period ended December 31, 2017 can be found on the Corporation's SEDAR profile at www.sedar.com.