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Persta Resources Inc.

(incorporated under the laws of Alberta with limited liability)

(Stock Code: 3395)

ANNUAL RESULTS ANNOUNCEMENT FOR THE YEAR ENDED DECEMBER 31, 2017

FINANCIAL AND OPERATING HIGHLIGHTS

	Year ended December 31,		**Increase/**
	2017	2016	**(Decrease)**
	C\$'000	*C\$'000*	**%**
Production revenue from crude oil and natural gas sales	**21,443**	23,706	**(9.5)**
Trading revenue from natural gas sales	**1,241**	—	**N/A**
Operating Netback*(Note 1)*	**13,645**	15,599	**(12.5)**
Adjusted EBITDA*(Note 2)*	**7,544**	12,898	**(41.5)**
Loss and total comprehensive loss for the year attributable to owners of the Company	**(11,637)**	(2,286)	**409.1**
Loss per share	**(0.04)**	(0.01)	**300.0**
Total production volume (Boe)	**1,042,571**	1,310,000	**(20.4)**
Daily average production volume (Boe/d)	**2,856**	3,579	**(20.2)**

Note 1: Operating Netback is defined as revenue less royalties, trading cost and operating costs. Operating Netback is a non-IFRS financial measure, see "Non-IFRS Financial Measures" on pages 30 to 31 of this announcement.

Note 2: Adjusted EBITDA is defined as earnings before deduction of finance expenses, income taxes, depletion and depreciation, write-offs, transaction costs and share-based compensation. Adjusted EBITDA is a non-IFRS financial measure, see "Non-IFRS Financial Measures" on pages 30 to 31 of this announcement.

The board of directors (the "**Board**") of Persta Resources Inc. ("**Persta**" or the "**Company**") hereby announces the annual results of the Company for the year ended December 31, 2017 together with the comparative figures for the year ended December 31, 2016 as follows:

STATEMENT OF LOSS AND OTHER COMPREHENSIVE LOSS
For the year ended December 31, 2017
(Expressed in Canadian dollars)

		Year ended December 31,	
		2017	2016
	Note	***C$***	*C$*
Production revenue from crude oil and natural gas sales	*4*	**21,443,207**	23,705,746
Royalties		**(2,793,481)**	(1,780,341)
		18,649,726	21,925,405
Trading revenue from natural gas sales	*4*	**1,240,648**	—
Trading cost from natural gas purchases		**(499,859)**	—
		740,789	—
Net revenue		**19,390,515**	21,925,405
Operating costs		**(5,746,160)**	(6,326,913)
General and administrative costs		**(6,149,973)**	(2,711,725)
Depletion and depreciation		**(6,179,377)**	(7,764,395)
Write-off of exploration and evaluation assets		**(900,685)**	(812,452)
Write-off of property, plant and equipment		**(2,212,697)**	—
Share-based compensation		**—**	(221,332)
(Loss)/profit from operations		**(1,798,377)**	4,088,588
Other income		**49,066**	11,174
Transaction costs		**(3,003,350)**	(2,980,561)
Finance expenses		**(6,884,131)**	(3,405,005)
Loss before income taxes		**(11,636,792)**	(2,285,804)
Income taxes	*5*	**—**	—
Loss and total comprehensive loss for the year attributable to owners of the Company		**(11,636,792)**	(2,285,804)
Loss per share			
Basic and diluted	*6*	**(0.04)**	(0.01)

The accompanying notes form part of the financial information.

STATEMENT OF FINANCIAL POSITION
As at December 31, 2017
(Expressed in Canadian dollars)

	Note	As at December 31, 2017 C$	2016 C$
ASSETS			
Current assets			
Cash and cash equivalents		**2,363,183**	3,966,154
Investments		**3,333,500**	—
Accounts receivable	*2*	**1,813,992**	3,228,055
Prepaid expenses, deposits and deferred financing costs		**870,286**	1,385,198
		8,380,961	8,579,407
Non-current assets			
Exploration and evaluation assets		**40,065,106**	14,562,811
Property, plant and equipment		**62,645,297**	68,288,825
		102,710,403	82,851,636
TOTAL ASSETS		**111,091,364**	91,431,043

STATEMENT OF FINANCIAL POSITION (Continued)
As at December 31, 2017
(Expressed in Canadian dollars)

		As at December 31,	
		2017	2016
	Note	***C$***	*C$*
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	*3*	**8,230,602**	3,457,229
Bank loan		**22,197,243**	—
Decommissioning liabilities		**205,429**	—
		30,633,274	3,457,229
Non-current liabilities			
Other liabilities		**3,798,280**	—
Bank loan		**—**	35,055,200
Decommissioning liabilities		**1,966,719**	1,708,047
		5,764,999	36,763,247
Total liabilities		**36,398,273**	40,220,476
Shareholders' equity			
Share capital		**204,366,683**	169,247,367
Accumulated deficit		**(129,673,592)**	(118,036,800)
Total shareholders' equity		**74,693,091**	51,210,567
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY		**111,091,364**	91,431,043

The accompanying notes form part of the financial information.

NOTES TO THE FINANCIAL INFORMATION

For the year ended December 31, 2017

(Expressed in Canadian dollars unless otherwise indicated)

1 BASIS OF PREPARATION AND ACCOUNTING POLICIES

The financial information set out in this announcement does not constitute the financial statements of Persta Resources Inc. (the "**Company**") for the year ended December 31, 2017, but are extracted from the draft financial statements.

The draft financial statements have been prepared in accordance with all applicable International Financial Reporting Standards ("**IFRSs**"), which collective term includes all applicable individual IFRSs, International Accounting Standards ("**IASs**") and Interpretations issued by the International Accounting Standards Board ("**IASB**") and the disclosure requirements of the Hong Kong Companies Ordinance. The financial statements also comply with the applicable disclosure provisions of the Rules Governing the Listing of Securities on The Stock Exchange of Hong Kong Limited (the "**Listing Rules**").

2 ACCOUNTS RECEIVABLE

	As at December 31,	
	2017	2016
	C$	*C$*
Trade receivables	**1,813,992**	3,069,420
Other receivable		
— Amount due from Ji Lin Hong Yuan Trade Group Limited ("**JLHY**")*(Note)*	**—**	156,283
— Others	**—**	2,352
	1,813,992	3,228,055

Note: As at December 31, 2016, the amount due from JLHY was attributable to the settlement of withholding tax on behalf of JLHY by the Company. The amount was non-trade in nature, unsecured, non-interest bearing and due on demand, which was fully settled in February 2017.

(a) ***Aging analysis of trade receivables***

As at December 31, 2017, the aging analysis of trade receivables (included in accounts receivable), based on the invoice date (or date of revenue recognition, if earlier) and net of allowance for doubtful debts, is as follows:

	As at December 31,	
	2017	2016
	C$	*C$*
Within 1 month	**1,798,983**	3,054,555
1 to 2 months	**144**	428
Over 3 months	**14,865**	14,437
	1,813,992	3,069,420

Trade receivables are to be collected within 25 days from the date of billing.

(b) ***Impairment of accounts receivable***

Impairment losses in respect of trade receivables are recorded using an allowance account unless the Company determines that recovery of the amount is remote, in which case the impairment loss is written off against trade receivables directly. No impairment loss has been recognized in respect of trade receivables for the years ended December 31, 2017 and 2016.

No trade receivables, which are included in accounts receivable, are considered individually nor collectively to be impaired. No material balances of trade receivables are past due.

3 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	As at December 31,	
	2017	2016
	C$	*C$*
Trade payables	**182,386**	921,300
Accrued liabilities	**2,679,869**	1,511,302
Accrued compensation for independent non-executive directors per Phantom Unit Plan*(Note)*	**262,833**	140,000
Subtotal	**3,125,088**	2,572,602
Other payables	**5,105,514**	884,627
Total	**8,230,602**	3,457,229

Note: The accrued compensation for independent non-executive directors per Phantom Unit Plan will be accrued quarterly and paid in accordance with the terms set out in the Phantom Unit Plan as set out in the Company's prospectus dated 28 February 2017.

For the year ended December 31, 2017, the Company drilled four wells with C$4,362,647 of unpaid capital expenditure in other payables (2016: nil).

All trade payables and accrued liabilities are expected to be settled within one year or are payable on demand.

Aging analysis of trade payables and accrued liabilities

As at December 31, 2017, the aging analysis of trade payables and accrued liabilities (included in accounts payable and accrued liabilities), is as follows:

	As at December 31,	
	2017	2016
	C$	*C$*
Within 1 month	**1,226,481**	1,254,933
1 to 3 months	**1,635,774**	1,169,331
Over 3 months but within 6 months	**—**	8,338
	2,862,255	2,432,602

4 REVENUE

The amount of each significant category of revenue recognized for the years ended December 31, 2017 and 2016 is as follows:

	Year ended December 31,	
	2017	2016
	C$	*C$*
Production revenue from natural gas, natural gas liquids and condensate	**19,961,130**	22,605,768
Production revenue from crude oil	**1,482,077**	1,099,978
	21,443,207	23,705,746
Trading revenue from natural gas	**1,240,648**	—

For the year ended December 31, 2017, the Company's customer base includes two customers (2016: two customers), with whom transactions have exceeded 10% of the Company's revenues. For the year ended December 31, 2017, revenues from sales to these customers amounted to C$18,043,366 (2016: C$20,049,946).

5 INCOME TAXES

The provision for income taxes differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the loss before income taxes. The difference results from the following items.

	Year ended December 31,	
	2017	2016
	C$	*C$*
Loss before income taxes	**(11,636,792)**	(2,285,804)
Combined Federal and Provincial tax rate	**27%**	27%
Expected tax benefit	**(3,141,934)**	(617,167)
Increase/(decrease) in taxes resulting from:		
— Non-deductible expenses	**58,381**	61,593
— Change in unrecognized deferred tax assets	**3,083,803**	556,350
— Change in enacted tax rate and others	**(250)**	(776)
Income tax expense	**—**	—

During the year ended December 31, 2017, the blended statutory tax rate was 27% (2016: 27%).

The components of unrecognized deferred tax assets are as follows:

	Year ended December 31,	
	2017	2016
	C$	*C$*
Deferred tax assets have not been recognized in respect of the following temporary differences:		
Property, plant and equipment and exploration and evaluation assets	**18,412,877**	24,114,130
Decommissioning liabilities	**2,172,148**	1,708,048
Non-capital losses	**12,425,390**	—
Share issue costs and others	**4,233,255**	—
Total	**37,243,670**	25,822,178

At December 31, 2017, the Company has approximately C$140 million of tax deductions, which include non-capital losses carry forwards of approximately C$12 million that will expire in 2037.

6 LOSS PER SHARE

The calculation of basic loss per share is based on the loss of C$11,636,792 and C$2,285,804 for the years ended December 31, 2017 and 2016 respectively and is calculated as follows:

	Year ended December 31,	
	2017	2016
	Number of shares	*Number of shares*
Weighted average number of common shares		
At the beginning of the year	**208,706,520**	206,495,226
Effect of new shares issued	**56,617,150**	2,110,778
At the end of the year	**265,514,301**	208,606,004
	C$	*C$*
Loss for the year	**(11,636,792)**	(2,285,804)
Loss per share		
Basic and diluted	**(0.04)**	(0.01)

On April 29, 2016, the Company completed a re-designation of Class A common shares as common shares, a conversion of all Class B and Class C common shares for common shares on a 1:1 basis, and a share split of the issued and outstanding shares on the basis of every one common share for two common shares.

There were no dilutive potential common shares for the years ended December 31, 2017 and 2016 due to the loss and therefore, diluted loss per share is the same as basic loss per share.

7 DIVIDEND

The Board did not approve the payment of a dividend for the years ended December 31, 2017 and 2016.

8. SUBSEQUENT EVENTS

In February 2018 the Company's lender initiated its semi-annual borrowing base review of its credit facility. This review is anticipated to be completed in the second quarter of 2018. The Company has classified its debt facility as current as of December 31, 2017 and will amend its disclosures as necessary to reflect the results of the review in future filings.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("**MD&A**") of the financial condition and performance of the Company for the year ended December 31, 2017 should be read in conjunction with the Company's financial information and notes thereto for the year ended December 31, 2017. All amounts and tabular amounts in MD&A are stated in thousands of Canadian dollars unless indicated otherwise.

SELECTED ABBREVIATIONS

In this MD&A, the abbreviations set forth below have the following meanings:

Crude Oil and Natural Gas Liquids

Bbls/d or Bbl/d	barrels of oil per day
Bbls or Bbl	barrels of oil or barrel of oil
Boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
C$/Bbl	Canadian dollars per barrel of oil
C$/Boe	Canadian dollars per barrel of oil equivalent
Mbbls or Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
Mbpd	thousand barrels per day
MMbbls	million barrels of oil
MMbbls/d	million barrels of oil per day
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
US$/Bbl	US dollars per barrel of oil

Natural Gas

Bcf	billion cubic feet
Bcm	billion cubic meters
Cf	cubic feet
C$/Mcf	Canadian dollars per thousand cubic feet
C$/MMbtu	Canadian dollars per million British thermal units
GJ	gigajoule
GJ/d	gigajoules per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day

MMcfe	million cubic feet of gas equivalent
MMcfe/d	million cubic feet of gas equivalent per day
tcf	trillion cubic feet
US$/MMbtu	US dollars per million British thermal units

Other

km	kilometres
km^2	square kilometres
m	meters
m^3	cubic meters
mg	milligrams
^oC	degrees Celsius

Conversion Factors — Imperial to Metric

Bbl = 0.1590 cubic metres (m^3)

Mcf = 0.0283 cubic metres (10^3m^3)

acres = 0.4047 hectares (ha)

Btu = 1054.615 joules (J)

feet (ft) = 0.3048 metres (m)

miles (mi) = 1.6093 kilometres (km)

pounds (Lb) = 0.4536 kilograms (kg)

Boe Conversions — Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) 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. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

FORWARD LOOKING INFORMATION

Certain statements in this MD&A are forward-looking statements that are, by their nature, subject to significant risks and uncertainties and the Company hereby cautions investors about important factors that could cause the Company's actual results to differ materially from those projected in a forward-looking statement. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will", "expect", "anticipate", "estimate", "believe", "going forward", "ought to", "may", "seek", "should", "intend", "plan", "projection", "could", "vision", "goals", "objective", "target", "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks (including the risk factors detailed in this MD&A), uncertainties and other factors some of which are beyond the Company's control and which are difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements, the Company strongly cautions investors against placing undue reliance on any such forward-looking statements. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the resources and reserves described can be profitably produced in the future. Further, any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

All forward-looking statements in this MD&A are expressly qualified by reference to this cautionary statement.

NON-IFRS FINANCIAL MEASURES

The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and sometimes referred to in this MD&A as Generally Accepted Accounting Principles ("**GAAP**") as issued by the International Accounting Standards Board ("**IASB**").

This MD&A also includes references to financial measures commonly used in the oil and natural gas industry. These financial measures are not defined by IFRS as issued by IASB and, therefore, are referred to as non-IFRS measures. The non-IFRS measures used by the Company may not be comparable to similar measures presented by other companies. See "Non-IFRS Financial Measures" for information regarding the following non-IFRS financial measures used in this MD&A: "operating netback", "adjusted EBITDA" and "total debt".

OVERVIEW

The Company was incorporated in Calgary, Alberta, Canada under the Business Corporations Act (Alberta) in 2005. Persta is an exploration and development company pursuing petroleum and natural gas production and reserves in Alberta, Canada. Persta focuses on long-term growth through acquisition, exploration, development and production in the Western Canadian Sedimentary Basin

(“**WCSB**”). The Company’s shares were listed on The Stock Exchange of Hong Kong Limited (the “**Stock Exchange**”) on March 10, 2017 (the “**Listing Date**”) pursuant to an initial public offering and trades under the stock code of “3395”.

Persta commenced operations on March 11, 2005 with the objective of building a successful Canadian natural gas and crude oil exploration, development and production company with a long-term business strategy. The Company acquired its first 6,400 net acres of land in an area in the WCSB in January 2007 known as the Alberta Foothills and drilled and commercially produced liquids-rich natural gas from the Company’s first deep well in this area in December 2008. Since then, the Company’s natural gas and crude oil production rate has organically grown and reached the highest production of 4,044 Boe/d for the year ended December 31, 2017. As at December 31, 2017, the Company held 118,807 net acres of land in the WCSB, which the Company intends to explore through drilling in locations listed in the Company’s multi-year inventory.

Presently, the Company has three core areas of operations:

- Alberta Foothills, which includes natural gas properties in the five areas of Basing, Voyager, Kaydee, Columbia and Stolberg. Basing is partially developed whilst Voyager, Kaydee, Columbia and Stolberg are undeveloped;

- Deep Basin Devonian, which includes undeveloped natural gas properties in Hanlan-Peco in West Alberta; and

- Peace River, which includes light oil properties in the Dawson area which is partially developed.

The Company’s long-term business strategy is to increase shareholder value by continuing to exploit and develop its oil and natural gas asset base in the three core exploration and production areas to increase its reserves, production and cash flows. The Company believes that it has a number of key strengths that will help the Company to execute its long-term business strategies, which include:

- economics and quality of resource base;

- size of resources within the Company’s acreage land position;

- location of resources and market access;

- holding sole operating control and land ownership; and

- an experienced management and technical team with a strong industry track record.

FUTURE PROSPECTS

The Company acquired Petroleum and Natural Gas ("**PNG**") Licenses for Basing, Voyager and Kaydee in the Alberta Foothills and for Dawson in Peace River between 2006 and 2017. The Company plans to initially develop its natural gas assets in Basing as part of its three-year development plan in addition to constructing certain facilities to support future increases in production and to lower production costs in the long run.

The Company also intends to explore and develop its resources in Voyager and Kaydee in the Alberta Foothills to expand reserves and also the undeveloped lands in Stolberg, Columbia and Deep Basin Devonian in the future.

THE RESERVES ESTIMATED BY GLJ

As at December 31, 2017	**Total**	**Natural gas**	**Crude oil, condensate and other natural gas liquids ("NGLs")**
	Mboe	%	%
Gross Proved Reserves	**10,806**	**94.6**	**5.4**
Gross Proved plus Probable Reserves	**15,220**	**94.6**	**5.4**

As at December 31, 2016	Total	Natural gas	Crude oil, condensate and other NGLs
	Mboe	%	%
Gross Proved Reserves	11,758	94.8	5.2
Gross Proved plus Probable Reserves	17,386	94.9	5.1

OPERATIONAL HIGHLIGHTS

For the year ended December 31, 2017, the Company achieved progress in the following areas:

- Acquired a total of 6,880 acres of land in the Alberta Foothills and Peace River Dawson areas with 100% working interest to further expand the Company's land position in core areas.
- Drilled four new wells targeting the Wilrich, Cardium and Mountain-Park formations and discovered natural gas resources in the Voyager area.
- Completed the workovers of existing wells to improve its performance and production at Basing in the Alberta Foothills and Dawson in Peace River area.

- Initiated front end engineering design ("**FEED**") for proposed future gas gathering and processing facilities.

SELECTED ANNUAL INFORMATION

	Year ended December 31,			
	2017	2016	2015	2014
AVERAGE DAILY PRODUCTION				
Natural gas (Mcf)	**15,879**	20,147	10,380	15,611
Crude oil (Bbls)	**70**	61	54	102
NGLs and Condensate (Bbls)	**140**	161	85	81
Oil Equivalent (Boe)	**2,856**	3,579	1,868	2,786
AVERAGE DAILY TRADING				
Natural gas (Mcf)	**194**	—	—	—
AVERAGE SALES PRICES				
Natural gas (C$ per Mcf)	**2.98**	2.72	3.61	4.70
Crude oil (C$ per Bbl)	**58.02**	49.53	49.09	93.50
NGLs (C$ per Bbl)	**28.10**	19.96	17.98	51.05
Condensate (C$ per Bbl)	**62.77**	52.81	61.81	88.92
FINANCIAL ($'000)				
Revenue	**22,684**	23,706	16,080	32,424
Trading cost	**(500)**	—	—	—
Royalties	**(2,793)**	(1,780)	(1,072)	(5,295)
Operating costs	**(5,746)**	(6,327)	(3,636)	(5,556)
Operating netback*(Note 1)*	**13,645**	15,599	11,371	21,573
Net (loss)/earnings	**(11,637)**	(2,286)	(2,485)	3,002
Net working capital*(Note 2)*	**(22,252)**	5,122	6,923	4,514
Total assets	**111,091**	91,431	100,547	105,078
Capital expenditures	**22,197**	1,412	5,374	18,208
OPERATING NETBACK PER SHARE*(Note 3)*				
Per basic share	**0.05**	0.07	0.06	0.14
Per diluted share	**0.05**	0.07	0.06	0.14
(LOSS)/PROFIT PER SHARE				
Per basic share	**(0.04)**	(0.01)	(0.01)	0.02
Per diluted share	**(0.04)**	(0.01)	(0.01)	0.02

Notes:

(1) Non-IFRS measure — see discussion under the heading "Non-IFRS Financial Measures".

(2) Net working capital consists of current assets less current liabilities.

(3) Operating netback per share is a non-IFRS financial measure calculated as operating netback divided by weight average number of common shares.

KEY FINANCIAL RATIOS

	Year ended December 31,			
	2017	2016	2015	2014
Current ratio *(Note 1)*	**0.27x**	2.48x	4.08x	1.79x
Return on assets *(Note 2)*	**–10.5%**	–2.5%	–2.5%	2.9%
Return on equity *(Note 3)*	**–15.6%**	–4.5%	–4.8%	5.8%
Gearing ratio *(Note 4)*	**34.8%**	69.6%	87.9%	90.9%

Notes:

(1) Current assets divided by current liabilities

(2) (Loss)/profit and total comprehensive (loss)/income for the year attributable to the owners of the Company divided by total assets and multiplied by 100%

(3) (Loss)/profit and total comprehensive (loss)/income for the year attributable to owners of the Company divided by total equity and multiplied by 100%

(4) Total debt which represents bank indebtedness, bank loan, shareholders' loan and other debts divided by total equity and multiplied by 100%

RESULTS OF OPERATIONS

Project Development and Production Volume

There are three phases in the Company's operations, comprising the exploration phase, the development phase and the production phase. During the exploration phase, the Company conducts geological and geophysical studies combined with seismic mapping to propose drilling locations which might generate natural gas and crude oil prospects on the undeveloped land the Company has acquired.

During the development and production phases, the Company's production volumes largely depend on its drilling and production schedule and access to transport and processing infrastructure to refine and deliver the Company's products to a sales point. There were 5 natural gas producing wells and 3 crude oil wells both as at December 31, 2017 and 2016.

Pricing forecasts directly affect the production volume of the Company. Producing wells may be shut in due to economic limit considerations and the production plan may be delayed or scaled down should there be unfavorable prices on the natural resources.

The natural gas market remains weakened in 2017, so the Company has strategically shut-in some production in response to the soft market, whilst retaining the reserves/resources for future recovery and long term growth. On the other hand, the Company has taken advantage of the low price environment and purchased from the market to fulfill the committed forward contracts for natural gas, saving operating costs and arbitraging from the price difference. The NGLs and condensate are the by-products from the production of natural gas and their production volumes decreased accordingly. In the meantime, the Company increased the production volumes of crude oil in 2017, which was mainly due to the recovery of the market price of crude oil since the second half of 2017.

For the year ended December 31, 2017, the Company's total production volume decreased by 267,429 Boe to 1,042,571 Boe compared to 1,310,000 Boe for the same period in 2016. It is noteworthy that the average production volume of 2,856 Boe/d for full year 2017 does not represent the Company's true production capability but is a result from our strategic shut-in.

The following table shows the number of producing wells and production volume for the Company's natural gas, crude oil, NGLs and condensate for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
Natural gas			
Producing wells (number of wells)	**5**	5	0.0%
Production volume (Mcf)	**5,795,775**	7,373,968	–21.4%
Natural gas			
Trading volume (Mcf)	**425,075**	—	N/A
Crude oil			
Producing wells (number of wells)	**3**	3	0.0%
Production volume (Bbl)	**25,546**	22,209	15.0%
NGLs and Condensate (by-product of natural gas)			
Producing wells (number of wells)	**5**	5	0.0%
Production volume (Bbl)	**51,062**	58,797	–13.2%
Total			
Producing wells (number of wells)	**8**	8	0.0%
Production volume (Boe)	**1,042,571**	1,310,000	–20.4%
Trading volume (Boe)	**70,846**	—	N/A

Average Sales Price

The Company mainly sells its natural gas, natural gas related products (NGLs and condensate) and crude oil products to gas and oil trading companies or companies involved in gas and oil trading. The selling price of its natural gas benchmarks to Canadian Gas Price Reporter, which is also known as the Alberta Energy Company natural gas price ("**AECO natural gas price**"), while the natural gas related products (NGLs and condensate) and crude oil products benchmark to the Edmonton light, sweet crude oil commodity price. During the year ended December 31, 2017, the Company also had in place one-year (January 1, 2017 to December 31, 2017) sales agreements to forward sell its natural gas at a specified price and volume. These sales values accounted for 84.6% of the Company's total revenue from crude oil and natural gas sales for the year ended December 31, 2017, compared with 50.0% for the same period in 2016. The sales of remaining production accounted for 15.4% of its total revenue from crude oil and natural gas sales for the year ended December 31, 2017, compared with 50.0% for the same period in 2016.

During the year ended December 31, 2017, the Company had strategically shut-in some production in response to the soft market, whilst retaining the reserves/resources for future recovery and long term growth. The Company has taken advantage of the low price environment and purchased 425,075 Mcf of natural gas from the market to fulfill the committed forward contracts for natural gas, saving on operating costs and arbitraging from the price difference.

The following table shows the average market prices and average sales prices for the Company's natural gas, crude oil, NGLs and condensate and the average realized price, average trading sales price and average forward sales price for the Company's natural gas for the year ended December 31, 2017:

	Year ended December 31,		
	2017	2016	Change
	C$	*C$*	%
Natural gas			
Average market price (C$ per Mcf) *(Note 1)*	**2.33**	2.37	–1.7%
Average realized price (C$ per Mcf) *(Note 2)*	**2.79**	2.29	21.8%
Average forward sales price (C$ per Mcf) *(Note 3)*	**3.02**	3.12	–3.2%
Average trading sales price (C$ per Mcf) *(Note 4)*	**2.92**	—	N/A
Average sales price (C$ per Mcf) *(Note 5)*	**2.98**	2.72	9.6%
Crude oil			
Average market price (C$ per Bbl) *(Note 6)*	**62.78**	57.32	9.5%
Average sales price (C$ per Bbl) *(Note 5)*	**58.02**	49.53	17.1%
NGLs			
Average market price (C$ per Bbl) *(Note 7)*	**36.61**	23.70	54.5%
Average sales price (C$ per Bbl) *(Note 5)*	**28.10**	19.96	40.8%

	Year ended December 31,		
	2017	2016	Change
	C$	*C$*	*%*
Condensate			
Average market price (C$ per Bbl) *(Note 7)*	**66.80**	56.12	19.0%
Average sales price (C$ per Bbl) *(Note 5)*	**62.77**	52.81	18.9%

Notes:

(1) The average market price was the AECO same day spot price averaged over the year.

(2) The average realised price represents the average price of natural gas sales excluding the sales derived from forward sales and trading sales.

(3) The average forward sales price was the price agreed in the forward sales agreements to sell the Company's natural gas at a specified price and volume.

(4) The average trading sales price was the weighted average price of sales for trading business.

(5) The average sales price was the weighted average price calculated by the Company.

(6) The average market price was the average Edmonton light, sweet crude oil settlement price over the year.

(7) The average market price was the average Alberta natural gas liquids price over the year.

Natural Gas

The Company's average sales price of natural gas consists of two components: the weighted average of the realized price and the average forward sales price of natural gas. The average realized price represents the average price of natural gas sales excluding the sales derived from forward sales.

For the year ended December 31, 2017, and comparing to the same period of 2016, the average market price of natural gas has decreased from C$2.37 per Mcf to C$2.33 per Mcf. The price recovery has helped the average realized price of natural gas to increase by 21.8% from C$2.29 per Mcf to C$2.79 per Mcf. This was offset by the 3.2% decrease of average forward sales price during the same period. To exploit weakness in the current market, the Company purchased natural gas from the market to fulfill the forward sales contracts with an weighted average price of C$2.92 per Mcf. The aforementioned factors collectively led to a 9.6% increase of the average natural gas sales price from C$2.72 per Mcf to C$2.98 per Mcf for the year ended December 31, 2017, compared to the same period of 2016.

Crude oil

The average market price of crude oil increased from C$57.32 per Bbl for the year ended December 31, 2016 to C$62.78 per Bbl for the same period in 2017. As a result, the Company's average sales price increased by 17.1% from C$49.53 per Bbl for the year ended December 31, 2016 to C$58.02 per Bbl for the same period in 2017.

NGLs

The average market price of NGLs increased from C$23.70 per Bbl for the year ended December 31, 2016 to C$36.61 per Bbl for the same period in 2017. As a result, the Company's average sales price increased 40.8% from C$19.96 per Bbl for the year ended December 31, 2016 to C$28.10 per Bbl for the same period in 2017.

Condensate

The average market price of condensate increased from C$56.12 per Bbl for the year ended December 31, 2016 to C$66.80 per Bbl for the same period in 2017, as a result, the Company's average sales price increased by 18.9% from C$52.81 per Bbl for the year ended December 31, 2016 to C$62.77 per Bbl for the same period in 2017.

The Company sells its natural gas benchmarked to the AECO natural gas price, crude oil benchmarked to the Edmonton light, sweet crude oil settlement price, and its NGLs and condensate benchmarked to the average Alberta natural gas liquids price. The Company also enters into forward sales agreements to sell its natural gas over a time period at a specified price and volume. Since the Company uses weighted average to calculate the average sales prices, the volatilities in price and volume sold each day will cause the average sales price of crude oil, NGLs and condensate and the average realized price of natural gas to be either lower or higher than the average market price for the same periods in 2017 and 2016.

Revenue

The following table shows the breakdown of the Company's revenue before royalties by types of natural resources for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Natural gas	**18,543**	20,050	–7.5%
Crude oil	**1,482**	1,100	34.7%
NGLs and condensate	**2,659**	2,556	4.0%
Total revenue	**22,684**	23,706	–4.3%

Sales of Natural Gas

The following table shows the sales volume and average sales price of the Company's natural gas for the year ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change %
Sales volume (Mcf)	**6,220,850**	7,373,968	–15.6%
Realized sales volume	**891,425**	3,562,451	–75.0%
Forward sales volume	**4,904,350**	3,811,517	28.7%
Trading sales volume	**425,075**	—	N/A
Average sales price (C$/Mcf)	**2.98**	2.72	9.6%
Realized sales price	**2.79**	2.29	21.8%
Forward sales price	**3.02**	3.12	–3.2%
Trading sales price	**2.92**	—	N/A

The revenue derived from the Company's sales of natural gas is a function of the average price and volume of natural gas sold. The Company's average sales price of natural gas consisted of the weighted average of the realized price and the forward sales price of natural gas. The sales volume of the Company's natural gas was dependent on the Company's production capacity influenced by its drilling plan and production wells in Alberta Foothills. Although the Company decreased its production volume in response to the soft market, the average sales price increased due to the forward sales contracts which fixed a sale price higher than the market price.

Sales of Crude Oil

The following table shows the sales volume and average sales price of the Company's crude oil for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change %
Sales volume (Bbl)	**25,546**	22,209	15.0%
Average sales price (C$/Bbl)	**58.02**	49.53	17.1%

The revenue derived from the Company's sales of crude oil was mainly subject to the average sales price and the sales volume of crude oil. The average sales price of the Company's crude oil is highly sensitive to Edmonton light, sweet crude oil price; and the sales volume of its crude oil was dependent on the Company's production capacity influenced by its drilling plan and production wells from the

Peace River area. Due to the improvement in the market price of crude oil, the average sales price increased, and the Company resumed the production from its oil well in Dawson area and increased its production volume in response to the improvement in the market price of crude oil.

Sales of NGLs and Condensate

The following table shows the sales volume and average sales price of the Company's NGLs for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change %
Sales volume (Bbl)	**15,771**	16,725	–5.7%
Average sales price (C$/Bbl)	**28.10**	19.96	40.8%

The following table shows the sales volume and average sales price of the Company's condensate for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change %
Sales volume (Bbl)	**35,291**	42,072	–16.1%
Average sales price (C$/Bbl)	**62.77**	52.81	18.9%

The revenue derived from the Company's sales of NGLs and condensate was mainly affected by the average sales price and sales volume of such products. Both the average sales price of the Company's NGLs and condensate are highly sensitive to the Alberta natural gas liquids commodity price and demand of the petrochemical industry, and the sales volume of its NGLs and condensate was dependent on the Company's production capacity influenced by its drilling plan and production wells in the Alberta Foothills area. Due to the improvement in the market price of NGLs and condensate, the average sales price increased, and as a by-product, the production volume decreased as a result of the decrease of natural gas production volume.

Trading Cost of Natural Gas

The following table shows the purchase volume and average purchase price of the Company's natural gas for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
			%
Purchase volume (Mcf)	**425,075**	—	N/A
Average purchase price (C$/Mcf)	**1.18**	—	N/A

Royalties

The following table shows the breakdown of the Company's royalties by types of natural resources for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	%
Natural gas, NGLs and condensate	**2,375**	1,487	59.7%
Crude oil	**418**	293	42.7%
Total royalties	**2,793**	1,780	56.9%

For the year ended December 31, 2017, the average royalty rate increased by 4.8% to 12.3% compared to 7.5% for the same period in 2016. The increase of the average royalty rate was primarily due to expiry of a royalty holiday during April 2017 for a natural gas well drilled in 2013.

Alberta requires royalties to be paid on the production of natural resources from lands for which it owns the mineral rights. In Alberta, royalties are mainly subject to royalty rate and royalty base, which are set by a sliding scale formula containing separate elements that account for market price and well production. Royalty rates will drop reflecting declining production rates when the well reaches a maturity threshold.

During the year ended December 31, 2017, the Company's royalty rate for natural gas ranged from 5% to 23%, the royalty rate for NGLs (propane and butane) was 30%, the royalty rate for condensate was 40%, and the royalty rate for crude oil ranged from 18% to 35%. The Company's royalty rate was also influenced by the Modernizing Alberta's Royalty Framework under which a company will pay a flat royalty of 5% on a well's early production until the well's total revenue, from all hydrocarbon products, equals the drilling and completion cost allowance as defined in the Alberta's Royalty Framework.

Natural gas, NGLs and condensate

For the year ended December 31, 2017, the royalties paid for natural gas, NGLs and condensate increased by C$887,166 to C$2,374,735 compared to C$1,487,569 for the same period in 2016, representing 85.0% and 83.6% of the total royalties respectively. The increase of royalties was primarily due to expiry of a royalty holiday during April 2017 from a natural gas well drilled in 2013.

Crude oil

For the year ended December 31, 2017, the royalties paid for crude oil increased by C$125,974 to C$418,746 compared to C$292,772 for the same period in 2016, representing 15.0% and 16.4% of the total royalties respectively. The increase of royalties was primarily due to the resumption of production from the oil well in Dawson area and increase of production volume in response to the improvement in the market price.

Operating Costs

The following table shows the breakdown of the Company's operating costs by types of natural resources for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
Total operating costs	***C$'000***	*C$'000*	%
Natural gas, NGLs and condensate	**5,372**	6,043	–11.1%
Crude oil	**374**	284	31.7%
Total	**5,746**	6,327	–9.2%
Average operating costs	**C$**	C$	%
Natural gas, NGLs and condensate (Per Boe)	**5.28**	4.69	12.6%
Crude oil (Per Bbl)	**14.63**	12.78	14.5%
Average cost (Per Boe)	**5.51**	4.83	14.1%

For the year ended December 31, 2017, the operating costs decreased by C$580,753 to C$5,746,160, compared to C$6,326,913 for the same period in 2016, which was mainly due to the decrease in production volumes of natural gas, crude oil and NGLs and condensate.

Natural Gas, NGLs and Condensate

Most of the Company's revenue was generated from the sales of natural gas, NGLs and condensate. As a result, the majority of operating costs come from the natural gas related business.

For the year ended December 31, 2017, and comparing to the same period of 2016, the market price of natural gas has decreased, and the Company has strategically shut-in some production in response to the soft market, whilst retaining the reserves/resources for future recovery and long term growth. The Company has taken advantage of the low price environment and purchased from the market to fulfill the committed forward contracts for natural gas, saving operating costs and arbitraging from the price difference.

The average operating costs for the year ended December 31, 2017 increased by C$0.59 per Boe to C$5.28 per Boe compared to C$4.69 per Boe for the same period in 2016, attributable to the take or pay payment of gas gathering, processing and transportation fees for committed volume.

Crude Oil

The market price of crude oil increased in the second half of 2017, therefore the Company resumed the production from the oil well in Dawson area which then led to the increase in both total and per unit operating costs for 2017.

The average operating costs for the year ended December 31, 2017 increased by C$1.85 per Bbl to C$14.63 per Bbl compared to C$12.78 per Bbl for the same period in 2016, which was due to the increase of liquid trucking and treatment cost and consumptions cost for recovery of production in Dawson area.

General and Administrative Costs

The following table shows the breakdown of the general and administrative costs for the years ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Staff costs	**2,323**	1,513	53.5%
Accounting, legal and consulting fees	**2,370**	252	840.5%
Office rent	**670**	530	26.4%
Other	**787**	417	88.7%
General and administrative expense	**6,150**	2,712	126.8%
Capitalized staff costs	**721**	444	62.4%

For the years ended December 31, 2017 and 2016, the general and administrative costs mainly consisted of staff costs, accounting, legal and consulting fees, office rental and others. Others mainly includes office supplies, insurance and travel and accommodation, etc.

For the year ended December 31, 2017, the general and administrative costs increased by C$3,438,248 to C$6,149,973 compared to C$2,711,725 for the same period in 2016, which was mainly due to an increase in staff cost and accounting, legal and consulting fees. The increase in staff costs was mainly due to: bonus for management of the Company after successful listing on the Stock Exchange. The increase in accounting, legal and consulting fee was mainly due to: (i) audit and review fees; (ii) lawyers' fees for legal matters; and (iii) compliance and consulting fees after successful listing on the Stock Exchange.

Phantom Unit Plan for independent non-executive Directors

The Company has in place a phantom unit plan for its independent non-executive directors effective on March 10, 2017 and applied retrospectively started from January 1, 2016 (the "Phantom Unit Plan"). In order for the eligible directors to receive phantom units, they need to complete a participation form prior to the commencement of each fee period (i.e. twelve-month period commencing January 1 and ending on December 31). For 2017 and 2016, each eligible Director agreed in writing to receive 60% of their fees (i.e. the designated percentage) relating to future services as a director in the form of phantom units under the Phantom Unit Plan. Since 2016, the eligible directors have agreed to receive C$15,000 quarterly under the Phantom Unit Plan (the "Phantom Fee").

Under the terms of the plan, the Company calculates the Phantom Units dividing the Phantom Fee by the weighted average-trading price of the Company's common shares for the 5 days preceding each quarter end multiplied by the number of Phantom Units awarded during the quarter. For the year ended December 31, 2017, total compensation accrued for each director under the Phantom Unit Plan is based on the total number of units awarded in the preceding quarters multiplied by the weighted average-trading price of the Company's common shares for the 5 days preceding the year end.

For the year ended December 31, 2017, the Company incurred C$122,833 (2016: C$140,000) of directors' compensation per the Phantom Unit Plan. As at December 31, 2017, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$262,833.

Finance Expenses

The following table shows the breakdown of the finance expenses for the year ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Interest expense and financing fees	**5,864**	3,063	91.4%
Amortization of debt issuance costs	**567**	315	80.0%
Loss on foreign exchange	**422**	—	N/A
Accretion expense	**31**	27	14.8%
Total finance expenses	**6,884**	3,405	102.2%

For the years ended December 31, 2017 and 2016, the finance expenses mainly consisted of interest expense on bank debt, foreign exchange gains and losses, financing costs, amortization of debt issuance costs and accretion expense. For the year ended December 31, 2017, finance expenses increased by C$3,479,126 to C$6,884,131 compared to C$3,405,005 for the same period in 2016. The increase of finance expenses was mainly due to the increase of finance expenses upon termination of the existing facility and entering into the new facility.

Amortization of debt issuance costs represented legal fees, commissions and commitment fees, which had been incurred since the closing of the credit and term facility arrangement in 2014. These costs were capitalized against the bank loan account and amortized as a debt issuance costs account. The Company amortized all the remaining amount of debt issuance costs as a result of termination of the existing facility and entering into the new facility.

The accretion expense is an expense recognized when updating the present value of the decommissioning provision.

Depletion and Depreciation

The following table shows the breakdown of the depletion and depreciation expenses for the year ended December 31, 2017 and 2016:

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Depletion	**6,171**	7,756	–20.4%
Depreciation	**8**	8	0.0%
Total depletion and depreciation	**6,179**	7,764	–20.4%
	C$	C$	%
Average depletion and depreciation (Per Boe)	**5.93**	5.93	0.0%

Depletion is calculated using the depletion base and the depletion ratio. Depletion is based upon the net book value of developed and producing assets at the end of the period and future development costs, and the depletion ratio is calculated based upon the production volume for the period divided by the total proved and probable reserves at the beginning of the period.

For the year ended December 31, 2017, the depletion expense comprised the depletion of developed and producing assets, and the depreciation expense comprised the depreciation of office fixed assets, include office furniture, office equipment, vehicles, computer hardware and computer software.

For the year ended December 31, 2017, the Company's depletion expense decreased by C$1,585,114 to C$6,170,771 compared to C$7,755,885 for the same period in 2016, which was mainly due to the increase in production volumes of natural gas in the Alberta Foothills.

Write-offs

During the years ended December 31, 2017 and 2016, the change in write-offs was mainly due to the expiry of certain Crown Leases and PNG Licenses.

Exploration and Evaluation Assets

For the year ended December 31, 2017, the Company recorded write-offs of exploration and evaluation lands totaling C$900,685 compared to C$812,452 for the same period in 2016. The write-offs resulted from the Company's decision to allow certain non-core lands with no future prospective value to expire.

Property, Plant and Equipment

For the year ended December 31, 2017, the Company recorded write-offs of developing and producing lands totaling C$2,212,697 as a result of the Company's decision to allow certain non-core lands with no future prospective value to expire; the Company had no write-offs for the year ended December 31, 2016.

Share-based Compensation

There was no share-based compensation during the year ended December 31, 2017. During the year ended December 31, 2016, the Company issued Class B shares to employees for cash proceeds. The deemed price of Class B shares issued was higher than the actual price, which resulted in share-based compensation of C$221,332.

Transaction Costs

Transaction costs represents listing expenses incurred in the process of getting the Company listed on the Stock Exchange.

For the year ended December 31, 2017, transaction costs increased by C$22,789 to C$3,003,350 compared to C$2,980,561 for the same period in 2016.

On March 10, 2017, the Company was successfully listed on the Stock Exchange and the Company issued 69,580,000 new shares at HK$3.16 per share (C$0.55 per share), raising gross proceeds of HK$220 million (approximately C$38 million). The costs associated with the issuance of new shares, including the deferred financing cost of C$1 million up to December 31, 2016, were approximately C$3 million and therefore the net amount to be recorded as share capital was approximately C$35 million.

Realized Gain/(Loss) on Financial Derivative Instruments

The Company holds a number of financial instruments, the most significant of which are accounts receivable, accounts payable, cash and loans. The financial instruments are recorded at fair market values on the balance sheet.

The Company did not enter into any financial derivatives for the years ended December 31, 2017 and 2016.

For the year ended December 31, 2017, foreign exchange loss increased to C$421,822 compared to nil for the same period in 2016. The loss is related to the revaluation of monetary items held in Hong Kong Dollars and the value changes with the fluctuation in the Hong Kong Dollars/Canadian Dollars exchange rates. The Company is exposed to the financial risk related to the fluctuation of foreign exchange rates for the monetary assets and liabilities denominated in the currencies other than the functional currencies to which they relate. The Company has not hedged its exposure to currency fluctuation and the Company currently does not have a foreign currency hedging policy. However, management closely monitors foreign exchange exposure and will consider hedging significant foreign currency exposure should the need arise.

Net Loss

As a result of the above mentioned reasons, the net loss for the year ended December 31, 2017 increased by C$9,350,988 to C$11,636,792 compared to C$2,285,804 for the same period in 2016.

NON-IFRS FINANCIAL MEASURES

This MD&A or documents referred to in this MD&A make reference to the terms "operating netback", "adjusted EBITDA" and "total debt" which are not recognized measures under IFRS, and do not have a standardized meaning prescribed by IFRS. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Management considers operating netback an important measure to evaluate the Company's operational performance, as it demonstrates its field level profitability relative to current commodity prices. Management uses adjusted EBITDA to measure the Company's efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the non-IFRS measures should not be construed as an alternative to net income determined in accordance with IFRS as an indication of the Company's performance.

Operating netback

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	%
Revenue from crude oil and natural gas sales	**22,684**	23,706	–4.3%
Trading cost	**(500)**	—	N/A
Royalties	**(2,793)**	(1,780)	56.9%
Operating costs	**(5,746)**	(6,327)	–9.2%
Operating netback	**13,645**	15,599	–12.5%

Adjusted EBITDA

	Year ended December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Revenue from crude oil and natural gas sales	**22,684**	23,706	–4.3%
Trading Cost	**(500)**	—	N/A
Royalties	**(2,793)**	(1,780)	56.9%
Operating costs	**(5,746)**	(6,327)	–9.2%
General and administrative costs	**(6,150)**	(2,712)	126.8%
Other income	**49**	11	345.5%
Adjusted EBITDA	**7,544**	12,898	–41.5%

The terms "total debt" is not used by management in measuring performance but is used in the financial covenants under the Company's credit facility. Under the credit facility agreement "total debt" is defined as the consolidated debt of the Company and including any liability.

Total debt[(Note 1)]

	As at December 31,		
	2017	2016	Change
	C$'000	*C$'000*	*%*
Bank Loan[(Note 2)]	**22,197**	35,622	–37.7%
Other liabilities	**3,798**	—	N/A
Letter of credit	**558**	558	0.0%
Current liabilities (excluding bank loan)	**8,436**	3,457	144.0%
Total debt	**34,989**	39,637	–11.7%

Notes:

(1) As defined in credit agreement for the purposes of calculating financial based covenants.

(2) This amount only includes the actual drawdown from the credit facility.

RISK FACTORS & RISK MANAGEMENT

The liquidity position of Persta is expected to be improved by a material increase in future commodity prices and an increase in proved and probable reserves based on the Company's drilling program. The Company is involved in regular discussions with its lender and is continually pursuing other financing opportunities such as alternative debt arrangements, joint venture opportunities, property acquisitions or divestitures and other recapitalization opportunities and is taking steps to manage its spending and leverage including the implementation of cost reduction and capital management initiatives. If the Company is unable to obtain additional financing or come to some other arrangement with its lender, it will be required to curtail certain capital expenditure activities and/or possibly be required to liquidate certain assets. Ongoing exploration and development of Persta's properties will require substantial additional capital investment. Failure to secure additional financing, and/or secure other funds from asset sales, would result in a delay or postponement of development of these prospective properties. There can be no assurance that additional financing will be available or that, if available, will be on terms favourable or acceptable to Persta.

Persta monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations, royalty regime or taxation. In addition, Persta maintains a level of liability, business interruption and property insurance which is believed to be adequate for the Company's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims. See "Forward-Looking Information" in this MD&A and "Risk Factors" in Persta's prospectus for additional information.

IMPACT OF NEW ENVIRONMENTAL REGULATIONS

The oil and gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of the

Company's business more expensive or prevent the Company from conducting its business as currently conducted. Persta focuses on conducting transparent, safe and responsible operations in the communities in which its people live and work.

REVIEW OF ANNUAL RESULTS

The annual results announcement of the Company for the year ended December 31, 2017, was reviewed by the Audit and Risk Committee of the Company and approved by the Board. The financial figures in respect of the Company's statement of financial position, statement of loss and other comprehensive loss, and the related notes thereto for the year ended December 31, 2017 as set out in the preliminary announcement have been compared by the Company's auditor, KPMG LLP, Chartered Professional Accountants, to the amounts set out in the Company's draft financial statements for the year and the amounts were found to be in agreement. The work performed by KPMG LLP in this respect did not constitute an audit, review or other assurance engagement in accordance with International Standards on Auditing, International Standard on Review Engagements or International Standard on Assurance Engagements issued by the International Auditing and Assurance Standards Board and consequently no assurance has been expressed by the auditor.

OTHER INFORMATION

FINAL DIVIDEND

The Board does not recommend the payment of a final dividend for the year ended December 31, 2017 (year ended December 31, 2016: nil).

RECORD DATE

All registered shareholders of the Company as at 4:30 p.m. on April 24, 2018 (Hong Kong time) and 2:30 a.m. on April 24, 2018 (Calgary time), as the case may be, may vote in person at the annual general and special meeting or any adjournments thereof, or they (including a beneficial shareholder of the Company) may appoint another person (who need not be a shareholder) as their proxy to attend and vote in their place.

EVENTS AFTER THE REPORTING PERIOD

In February 2018, the Company's lender initiated its semi-annual borrowing base review of its credit facility. This review is anticipated to be completed in the second quarter of 2018. The Company has classified its debt facility as current as of December 31, 2017 and will amend its disclosures as necessary to reflect the results of the review in future filings.

CORPORATE GOVERNANCE PRACTICES

The Company is committed to maintaining high standards of corporate governance to safeguard the interests of shareholders and to enhance corporate value and accountability. The Board has adopted the principles and the code provisions of the Corporate Governance Code (the "**CG Code**") contained in Appendix 14 to the Listing Rules to ensure that the Company's business activities and decision making processes are regulated in a proper and prudent manner.

Mr. Le Bo is the chairman of the Board and chief executive officer of the Company. Although this deviates from the practice under code provision A.2.1 of the CG Code, where it provides that the two positions should be held by two different individuals, as Mr. Bo has considerable experience in the enterprise operation and management of the Company, the Board believes that it is in the best interests of the Company and its shareholders as a whole to continue to have Mr. Bo as chairman of the Board so that it can benefit from his experience and capability in leading the Board in the long-term development of the Company. From a corporate governance point of view, the decisions of the Board are made collectively by way of voting and therefore the chairman should not be able to monopolize the decision-making of the Board. The Board considers that the balance of power between the Board and management can still be maintained under the current structure. The Board shall review the structure from time to time to ensure appropriate action be taken should the need arise.

Save as disclosed above, during the period from the Listing Date and up to the date of this announcement (the "**Period**"), the Company has complied with the CG Code.

MODEL CODE FOR SECURITIES TRANSACTIONS

The Company has adopted the Model Code for Securities Transactions by Directors of Listed Issuers as set out in Appendix 10 to the Listing Rules (the "**Model Code**") as its code of conduct regarding dealings in the securities of the Company by the Directors and the Company's senior management who, because of his/her office or employment, is likely to possess inside information in relation to the Company's securities.

Upon specific enquiry, all Directors confirmed that they have complied with the Model Code during the Period. In addition, the Company is not aware of any non-compliance of the Model Code by the senior management of the Company during the Period.

PURCHASE, SALE OR REDEMPTION OF LISTED SECURITIES OF THE COMPANY

The shares of the Company were first listed on the main board of the Stock Exchange on the Listing Date. The Company has not purchased, redeemed or sold any of its listed securities during the Period.

PUBLICATION OF INFORMATION

This announcement is published on the websites of the Stock Exchange (**www.hkexnews.hk**) and the Company (**www.persta.ca**).

This announcement is prepared in both English and Chinese and in the event of inconsistency, the English text of this announcement shall prevail over the Chinese text.

By order of the Board
Persta Resources Inc.
Le Bo
Chairman

Calgary, March 27, 2018
Hong Kong, March 27, 2018

As at the date of this announcement, the executive director is Mr. Le Bo; the non-executive director is Mr. Yuan Jing; and the independent non-executive directors are Mr. Richard Dale Orman, Mr. Bryan Daniel Pinney and Mr. Peter David Robertson.