

# **FORM 51-101 F1**

**Tanager Energy Inc.  
Statement of reserves data  
and other oil and gas information  
as of December 31, 2016**

**Prepared by Deloitte  
April 27, 2017**

# Table of contents

	<b>Page</b>
Part 1 Date of statement	1
Part 2 Disclosure of reserves data	2
Part 3 Pricing assumptions	6
Part 4 Reconciliations of changes in reserves	8
Part 5 Additional information relating to reserves data	9
Part 6 Other oil and gas information	10
Appendix	
Forward looking statements	15
Reserve definitions	17
Glossary of abbreviations	18

## Part 1      Date of statement

Date of statement:      April 27, 2017  
Effective date:          December 31, 2016  
Preparation date:        April 27, 2017

Tanager Energy Inc.'s (the Company) Canadian oil and gas reserves were evaluated by Deloitte LLP (Deloitte), effective December 31, 2016. Deloitte was engaged by the Company to evaluate proved and proved plus probable reserves: no valuation of possible reserves or resources was undertaken. The Deloitte evaluation was prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook* (“COGE Handbook”).

Tanager Energy Inc.'s (the Company) American oil and gas reserves were evaluated by Rex D. Morris, effective December 31, 2016. Rex D. Morris was engaged by the Company to evaluate proved and proved plus probable reserves: no valuation of possible reserves or resources was undertaken. The Company engaged Deloitte to audit the report as prepared by Rex D. Morris to ensure it is in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook* (“COGE Handbook”).

The Company has assets located in both The United States and in Canada. The Company's Canadian oil and gas reserves are located ten miles northeast of Red Deer, Alberta in sections 22 and 23, township 39, range 26 W4M. The Company's American oil and gas reserves are located in Polk Co, Texas.

The reserves on the property described herein are estimates only. By nature, such forecasting of reserves and related economic parameters and analyses are forward-looking statements based on predictions of future events. Actual events or results may differ materially. Furthermore, the estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves.

In certain instances, numbers may not total due to computer-generated rounding.

**Part 2 Disclosure of reserves data**

**Item 2.1 Reserves data (forecast prices and costs)**

**Item 2.1.1 Breakdown of reserves (forecast case)**

**Tanager Energy Inc.**  
**NI 51-101 FORECAST CASE**  
**OIL AND GAS RESERVES SUMMARY**  
**Deloitte December 31, 2016 Forecast Pricing (CAD)**

Effective December 31, 2016

Canada

VOLUMES IN IMPERIAL UNITS																				
Light/Medium Crude		Oil						Natural Gas						Sulphur		Total BOE				
		Heavy Crude		Bitumen		Solution		Conventional		Coalbed Methane		Natural Gas Liquids								
CATEGORY	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	Mstb	Mstb	Mlt	Mlt	Mboe	Mboe		
PDP	11.2	8.9	0.0	0.0	0.0	0.0	41.2	33.6	0.0	0.0	0.0	0.0	1.7	1.0	0.2	0.1	19.8	15.6		
PDNP	114.1	82.5	0.0	0.0	0.0	0.0	501.8	396.5	0.0	0.0	0.0	0.0	20.8	12.9	2.0	1.4	218.6	161.4		
PUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TP	125.3	91.4	0.0	0.0	0.0	0.0	543.0	430.1	0.0	0.0	0.0	0.0	22.5	13.9	2.1	1.5	238.4	177.0		
PB	<u>110.8</u>	<u>78.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>530.7</u>	<u>423.7</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>22.0</u>	<u>15.5</u>	<u>2.1</u>	<u>1.6</u>	<u>221.3</u>	<u>164.1</u>		
P+P	236.1	169.4	0.0	0.0	0.0	0.0	1,073.7	853.9	0.0	0.0	0.0	0.0	44.6	29.4	4.2	3.1	459.6	341.1		

VOLUMES IN METRIC UNITS																				
Light/Medium Crude		Oil						Natural Gas						Sulphur		Total BOE				
		Heavy Crude		Bitumen		Solution		Conventional		Coalbed Methane		Natural Gas Liquids								
CATEGORY	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share	W.I	Co. Share
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	E3m3	E3m3	E3m3	E3m3	E3m3	E3m3	E6m3	E6m3	E6m3	E6m3	E6m3	E6m3	E3m3	E3m3	E3t	E3t	E3m3e	E3m3e		
PDP	1.8	1.4	0.0	0.0	0.0	0.0	1.2	0.9	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.1	3.1	2.5		
PDNP	18.1	13.1	0.0	0.0	0.0	0.0	14.1	11.2	0.0	0.0	0.0	0.0	3.3	2.0	2.0	1.4	34.7	25.7		
PUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TP	19.9	14.5	0.0	0.0	0.0	0.0	15.3	12.1	0.0	0.0	0.0	0.0	3.6	2.2	2.2	1.6	37.9	28.1		
PB	<u>17.6</u>	<u>12.4</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>15.0</u>	<u>11.9</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>3.5</u>	<u>2.5</u>	<u>2.1</u>	<u>1.6</u>	<u>35.2</u>	<u>26.1</u>		
P+P	37.5	26.9	0.0	0.0	0.0	0.0	30.3	24.1	0.0	0.0	0.0	0.0	7.1	4.7	4.3	3.2	73.0	54.2		

Light/Medium includes Tight and Synthetic Oil. Heavy includes Ultra Heavy and Pelican Lake Heavy in Alberta

Tanager Energy Inc.  
NI 51-101 FORECAST CASE  
OIL AND GAS RESERVES SUMMARY  
Deloitte December 31, 2016 Forecast Pricing (CAD)

Effective December 31, 2016

United States

## VOLUMES IN IMPERIAL UNITS

CATEGORY	Oil				Natural Gas				Natural Gas Liquids		Total BOE	
	Light/Medium Crude		Tight Oil		Solution		Conventional		WI Gross Mstb	Co. Share Net Mstb	WI Gross Mboe	Co. Share Net Mboe
	WI Gross Mstb	Co. Share Net Mstb	WI Gross Mstb	Co. Share Net Mstb	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf				
	WI Gross Mstb	Co. Share Net Mstb	WI Gross Mstb	Co. Share Net Mstb	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross Mstb	Co. Share Net Mstb	WI Gross Mboe	Co. Share Net Mboe
PDP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PDNP	0.0	0.0	115.3	43.2	1,416.3	531.1	0.0	0.0	0.0	0.0	351.3	131.8
PUD	0.0	0.0	432.3	126.4	5,310.0	1,553.2	0.0	0.0	0.0	0.0	1,317.3	385.3
TP	0.0	0.0	547.6	169.7	6,726.3	2,084.3	0.0	0.0	0.0	0.0	1,668.6	517.1
PB	0.0	0.0	2,110.2	463.7	54,350.8	12,135.2	0.0	0.0	0.0	0.0	11,168.7	2,486.2
P+P	0.0	0.0	2,657.8	633.4	61,077.1	14,219.5	0.0	0.0	0.0	0.0	12,837.3	3,003.3

## VOLUMES IN METRIC UNITS

CATEGORY	Oil				Natural Gas				Natural Gas Liquids		Total BOE	
	Light/Medium Crude		Tight Oil		Solution		Conventional		WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>3</sup> m <sup>3</sup> e	Co. Share Net E <sup>3</sup> m <sup>3</sup> e
	WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>6</sup> m <sup>3</sup>	Co. Share Net E <sup>6</sup> m <sup>3</sup>	WI Gross E <sup>6</sup> m <sup>3</sup>	Co. Share Net E <sup>6</sup> m <sup>3</sup>				
	WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>6</sup> m <sup>3</sup>	Co. Share Net E <sup>6</sup> m <sup>3</sup>	WI Gross E <sup>6</sup> m <sup>3</sup>	Co. Share Net E <sup>6</sup> m <sup>3</sup>	WI Gross E <sup>3</sup> m <sup>3</sup>	Co. Share Net E <sup>3</sup> m <sup>3</sup>	WI Gross E <sup>3</sup> m <sup>3</sup> e	Co. Share Net E <sup>3</sup> m <sup>3</sup> e
PDNP	0.0	0.0	18.3	6.9	39.9	15.0	0.0	0.0	0.0	0.0	55.8	20.9
PUD	0.0	0.0	68.7	20.1	149.6	43.8	0.0	0.0	0.0	0.0	209.3	61.2
TP	0.0	0.0	87.0	27.0	189.5	58.7	0.0	0.0	0.0	0.0	265.2	82.2
PB	0.0	0.0	335.3	73.7	1,531.3	341.9	0.0	0.0	0.0	0.0	1,774.8	395.1
P+P	0.0	0.0	422.3	100.7	1,720.8	400.6	0.0	0.0	0.0	0.0	2,040.0	477.3

Item 2.1.2 Net present value of future net revenue (forecast case)

**Tanager Energy Inc.**  
**NI 51-101 FORECAST CASE**  
**SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE - WITH CORPORATE TAX POOLS**  
**Deloitte December 31, 2016 Forecast Pricing (CAD)**

**Effective: December 31, 2016**

**Canada**

<b>BOE</b>											
<b>RESERVES CATEGORY</b>	<b>Before Income Taxes</b>					<b>After Income Taxes</b>					<b>10% BTAX \$/boe*</b>
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	
Proved Developed Producing	-205.2	-28.4	51.4	89.8	109.2	-205.2	-28.4	51.4	89.8	109.2	3.30
Proved Developed Non-Producing	2,313.2	1,570.1	1,085.4	755.6	523.3	2,193.6	1,502.7	1,046.1	732.2	508.8	6.72
Total Proved	2,107.9	1,541.7	1,136.7	845.5	632.5	1,988.3	1,474.3	1,097.5	822.0	618.1	6.42
Probable	3,945.8	2,307.2	1,453.1	979.2	698.1	2,948.6	1,756.1	1,123.4	769.5	558.4	8.85
Total Proved + Probable	6,053.7	3,848.9	2,589.9	1,824.7	1,330.6	4,937.0	3,230.5	2,220.9	1,591.5	1,176.4	7.59

**Effective: December 31, 2016**

**United States**

<b>BOE</b>											
<b>RESERVES CATEGORY</b>	<b>Before Income Taxes</b>					<b>After Income Taxes</b>					<b>10% BTAX \$/boe*</b>
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	
Proved Developed Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Proved Developed Non-Producing	3,891.2	2,605.4	1,910.3	1,486.3	1,203.5	2,568.2	1,740.1	1,289.3	1,012.5	826.7	14.50
Total Proved	12,390.3	8,292.8	5,881.7	4,334.7	3,277.5	8,177.6	5,528.8	3,951.8	2,928.3	2,220.9	11.38
Probable	70,150.3	49,794.1	37,946.2	30,170.7	24,683.0	46,249.7	33,260.4	25,630.2	20,585.3	16,998.2	15.26
Total Proved + Probable	82,540.6	58,086.9	43,827.9	34,505.4	27,960.5	54,427.3	38,789.1	29,582.0	23,513.6	19,219.1	14.59

Item 2.1.3 Additional information concerning future net revenue (forecast case)

Tanager Energy Inc.  
NI 51-101 FORECAST CASE  
TOTAL FUTURE NET REVENUE – WITH CORPORATE TAX POOLS  
Deloitte December 31, 2016 Forecast Pricing

Effective December 31, 2016

Category	Canada								
	Revenue	Royalties	Operating Costs	Investment Costs	Abandonment Costs	Well Costs	Future Net Revenue Before Income Tax	Income Taxes	Future Net Revenue After Income Tax
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
Proved Developed Producing	805.2	162.6	402.1	0.0	445.6		-205.2	0.0	-205.2
Proved Developed Non-producing	10,711.6	2,712.8	4,935.6	750.0	0.0		2,313.2	119.6	2,193.6
Total Proved	11,516.7	2,875.5	5,337.7	750.0	445.6		2,107.9	119.6	1,988.3
Probable	13,535.2	3,576.9	5,901.6	0.0	110.9		3,945.8	997.2	2,948.6
Total Proved + Probable	25,051.9	6,452.3	11,239.3	750.0	556.5		6,053.7	1,116.8	4,937.0

  

Category	United States								
	Revenue	Royalties	Operating Costs	Investment Costs	Abandonment Costs	Well Costs	Future Net Revenue Before Income Tax	Income Taxes	Future Net Revenue After Income Tax
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
Proved Developed Producing	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0
Proved Developed Non-producing	5,662.1	469.6	912.6	388.6	0.0		3,891.2	1,323.0	2,568.2
Total Proved	22,026.6	1,827.2	2,528.7	5,280.4	0.0		12,390.3	4,212.7	8,177.6
Probable	88,335.8	7,804.7	3,960.6	6,420.2	0.0		70,150.3	23,900.6	46,249.7
Total Proved + Probable	110,362.4	9,631.9	6,489.3	11,700.6	0.0		82,540.7	28,113.3	54,427.3

**Tanager Energy Inc.**  
**NI 51-101 FORECAST CASE**  
**FUTURE NET REVENUE BY PRODUCT TYPE**  
**Deloitte December 31, 2016 Forecast Pricing (CAD)**

**Effective December 31, 2016**

**Canada**

	Btax NPV @ 10%	Unit Value
	M\$	\$/Primary product
<b>TOTAL PROVED</b>		
Light and Medium Crude Oil (including solution gas and by-products)	1,222.2	13.37 \$/bbl
Conventional Natural Gas (including by-products but excluding solution and gas and by-products from oil wells)	-85.5	0.00 \$/Mcf
<b>Total</b>	1,136.7	6.42 \$/boe
<b>TOTAL PROVED + PROBABLE</b>		
Light and Medium Crude Oil (including solution gas and by-products)	2,675.4	15.79 \$/bbl
Conventional Natural Gas (including by-products but excluding solution and gas and by-products from oil wells)	-85.5	0.00 \$/Mcf
<b>Total</b>	2,589.9	7.59 \$/boe

**United States**

	Btax NPV @ 10%	Unit Value
	M\$	\$/Primary product
<b>TOTAL PROVED</b>		
Tight Oil (including solution gas and by-products)	5,881.7	34.66 \$/bbl
<b>Total</b>	5,881.7	11.38 \$/boe
<b>TOTAL PROVED + PROBABLE</b>		
Tight Oil (including solution gas and by-products)	43,827.9	69.20 \$/bbl
<b>Total</b>	43,827.9	14.59 \$/boe

**Item 2.2 Supplemental disclosure of reserves data (constant prices and costs)**

No supplemental disclosure using Constant Prices and Costs has been made.

**Part 3 Pricing assumptions**

**Item 3.1 Constant prices used in estimates**

Supplemental constant price estimates are not reported.

## Item 3.2 Forecast prices used in estimates

Forecast oil and gas prices are laid out in the Deloitte Price Forecast December 31, 2016 Table. All prices are stated in Canadian dollars unless otherwise indicated. Adjustments for oil differential and gas heating values are applied to these prices, as appropriate for each entity. Capital and operating costs are inflated.

Deloitte Resource Evaluation & Advisory Canadian  
Domestic Forecast  
Base Case Forecast Effective December 31 2016

		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	Crude Oil Pricing								Natural Gas Liquids Pricing Edmonton Par Prices				Natural Gas Pricing						Sulphur Alberta Plant Gate C\$/t Current
					WTI at Cushing		Edmonton	Edmonton	WCS		Bow River	Heavy Oil	Ethane	Propane	Butane	Pentanes +	Alberta Reference	Alberta AECO	Alberta AECO	B.C. Direct	NYMEX	NYMEX	
					Okla	Okla	City	City	20.5	25	12	Current	Current	Current	Condensate	Price	Average	Average	Stn. 2	Hub	Hub		
US\$/bbl	US\$/bbl	C\$/bbl	C\$/bbl	Deg. API	Deg. API	Deg. API		C\$/bbl	C\$/bbl	C\$/bbl	C\$/bbl	C\$/mcf	C\$/mcf	C\$/mcf	C\$/mcf	US\$/Mcf	US\$/Mcf	US\$/Mcf					
					Real	Current	Real	Current	Current	Current	Current	Current	Current	Real	Real	Current	Current	Real	Current				
H	2006	1.7%	1.7%	0.867	\$64.41	\$61.96	\$71.30	\$68.59	\$50.61	\$51.71	\$37.10	\$22.05	\$42.50	\$50.71	\$75.96	\$7.44	\$7.46	\$7.18	\$7.76	\$7.00	\$6.73	\$10.90	
i	2007	2.1%	2.1%	0.935	\$75.70	\$72.32	\$80.65	\$77.05	\$52.90	\$53.87	\$39.76	\$18.42	\$49.75	\$59.35	\$81.60	\$6.20	\$6.75	\$6.45	\$6.40	\$7.30	\$6.98	\$38.02	
s	2008	2.4%	2.4%	0.943	\$102.31	\$99.57	\$105.62	\$102.80	\$82.95	\$83.90	\$73.08	\$22.59	\$56.96	\$83.54	\$109.77	\$7.88	\$8.38	\$8.16	\$8.20	\$9.11	\$8.86	\$303.83	
t	2009	0.3%	0.3%	0.880	\$62.95	\$61.65	\$67.49	\$66.10	\$58.66	\$59.80	\$54.40	\$11.61	\$34.62	\$56.21	\$69.49	\$3.85	\$4.04	\$3.96	\$4.17	\$4.03	\$3.95	(\$5.08)	
o	2010	1.8%	1.8%	0.971	\$83.24	\$79.40	\$81.58	\$77.80	\$67.22	\$68.18	\$60.62	\$11.53	\$45.19	\$68.79	\$84.02	\$3.76	\$4.20	\$4.01	\$4.01	\$4.60	\$4.39	\$56.94	
r	2011	2.9%	2.9%	1.012	\$99.24	\$94.88	\$99.92	\$95.54	\$77.12	\$78.42	\$69.60	\$10.30	\$52.41	\$86.98	\$105.24	\$3.46	\$3.80	\$3.63	\$3.34	\$4.18	\$4.00	\$101.60	
i	2012	1.5%	1.5%	1.001	\$96.47	\$94.11	\$88.74	\$86.57	\$73.10	\$74.41	\$64.07	\$6.73	\$30.80	\$75.47	\$99.67	\$2.25	\$2.45	\$2.39	\$2.29	\$2.82	\$2.75	\$126.81	
c	2013	0.9%	0.9%	0.972	\$100.76	\$97.91	\$96.08	\$93.36	\$74.97	\$76.29	\$65.49	\$8.68	\$38.54	\$77.44	\$103.52	\$2.98	\$3.27	\$3.17	\$3.11	\$3.84	\$3.73	\$62.17	
a	2014	1.9%	1.9%	0.906	\$96.15	\$93.26	\$96.91	\$94.00	\$81.06	\$81.49	\$73.70	\$12.46	\$42.93	\$59.43	\$101.47	\$4.22	\$4.64	\$4.50	\$4.16	\$4.53	\$4.39	\$88.99	
l	2015	1.1%	1.1%	0.783	\$49.24	\$48.69	\$57.65	\$57.00	\$44.80	\$45.23	\$39.63	\$7.49	\$5.35	\$33.70	\$55.15	\$2.56	\$2.72	\$2.69	\$1.81	\$2.66	\$2.63	\$107.45	
2	12 Mths H	1.6%	1.6%	0.754	\$42.98	\$42.98	\$52.24	\$52.24	\$38.80	\$39.13	\$34.01	\$6.14	\$8.23	\$30.75	\$52.21	\$1.96	\$2.20	\$2.20	\$1.77	\$2.50	\$2.50	\$48.39	
0	0 Mths F	0.0%	0.0%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
1																							
6	Avg.	N/A	N/A	0.754	\$42.98	\$42.98	\$52.24	\$52.24	\$38.80	\$39.13	\$34.01	\$6.14	\$8.23	\$30.75	\$52.21	\$1.96	\$2.20	\$2.20	\$1.77	\$2.50	\$2.50	\$48.39	
F	2017	0.0%	0.0%	0.740	\$55.00	\$55.00	\$68.90	\$68.90	\$52.90	\$55.40	\$48.90	\$9.10	\$13.80	\$41.35	\$68.90	\$3.05	\$3.25	\$3.25	\$2.75	\$3.30	\$3.30	\$50.00	
o	2018	2.0%	2.0%	0.760	\$57.00	\$58.15	\$69.75	\$71.15	\$54.85	\$57.40	\$50.75	\$9.45	\$21.35	\$42.70	\$71.15	\$3.15	\$3.30	\$3.35	\$2.85	\$3.35	\$3.40	\$51.00	
r	2019	2.0%	2.0%	0.780	\$60.00	\$62.40	\$71.80	\$74.70	\$58.05	\$60.65	\$53.90	\$9.80	\$29.85	\$44.85	\$74.70	\$3.30	\$3.35	\$3.50	\$2.95	\$3.40	\$3.55	\$52.00	
e	2020	2.0%	2.0%	0.810	\$65.00	\$69.00	\$75.30	\$79.90	\$62.95	\$65.60	\$58.70	\$10.00	\$31.95	\$47.95	\$79.90	\$3.35	\$3.35	\$3.55	\$3.00	\$3.45	\$3.65	\$53.05	
c	2021	2.0%	2.0%	0.850	\$70.00	\$75.75	\$77.65	\$84.05	\$66.75	\$69.45	\$62.40	\$10.30	\$33.60	\$50.45	\$84.05	\$3.45	\$3.40	\$3.70	\$3.15	\$3.50	\$3.80	\$54.10	
a	2022	2.0%	2.0%	0.850	\$75.00	\$82.80	\$83.55	\$92.25	\$74.60	\$77.35	\$70.15	\$11.00	\$36.90	\$55.35	\$92.25	\$3.70	\$3.55	\$3.90	\$3.35	\$3.60	\$3.95	\$55.20	
s	2023	2.0%	2.0%	0.850	\$75.00	\$84.45	\$83.55	\$94.10	\$76.05	\$78.90	\$71.55	\$11.65	\$37.60	\$56.50	\$94.10	\$3.95	\$3.70	\$4.15	\$3.60	\$3.75	\$4.20	\$56.30	
t	2024	2.0%	2.0%	0.850	\$75.00	\$86.15	\$83.55	\$95.95	\$77.60	\$80.45	\$73.00	\$12.50	\$38.35	\$57.60	\$95.95	\$4.25	\$3.90	\$4.50	\$3.90	\$3.90	\$4.50	\$57.45	
	2025	2.0%	2.0%	0.850	\$75.00	\$87.85	\$83.55	\$97.90	\$79.15	\$82.05	\$74.45	\$13.10	\$39.15	\$58.75	\$97.90	\$4.45	\$4.00	\$4.70	\$4.10	\$4.00	\$4.70	\$58.60	
	2026	2.0%	2.0%	0.850	\$75.00	\$89.65	\$83.55	\$99.85	\$80.75	\$83.70	\$75.95	\$13.55	\$39.90	\$59.95	\$99.85	\$4.60	\$4.05	\$4.85	\$4.25	\$4.05	\$4.85	\$59.75	
	2027	2.0%	2.0%	0.850	\$75.00	\$91.40	\$83.55	\$101.85	\$82.35	\$85.40	\$77.45	\$14.00	\$40.70	\$61.15	\$101.85	\$4.75	\$4.10	\$5.00	\$4.40	\$4.10	\$5.00	\$60.95	
	2028	2.0%	2.0%	0.850	\$75.00	\$93.25	\$83.55	\$103.90	\$84.00	\$87.10	\$79.00	\$14.30	\$41.55	\$62.35	\$103.90	\$4.85	\$4.10	\$5.10	\$4.50	\$4.10	\$5.10	\$62.15	
	2029	2.0%	2.0%	0.850	\$75.00	\$95.10	\$83.55	\$105.95	\$85.65	\$88.85	\$80.60	\$14.60	\$42.35	\$63.60	\$105.95	\$4.95	\$4.10	\$5.20	\$4.55	\$4.10	\$5.20	\$63.40	
	2030	2.0%	2.0%	0.850	\$75.00	\$97.00	\$83.55	\$108.10	\$87.40	\$90.60	\$82.20	\$14.90	\$43.20	\$64.85	\$108.10	\$5.05	\$4.10	\$5.30	\$4.65	\$4.10	\$5.30	\$64.70	
	2031	2.0%	2.0%	0.850	\$75.00	\$98.95	\$83.55	\$110.25	\$89.15	\$92.45	\$83.85	\$15.15	\$44.05	\$66.15	\$110.25	\$5.15	\$4.10	\$5.40	\$4.75	\$4.10	\$5.40	\$65.95	
	2032	2.0%	2.0%	0.850	\$75.00	\$100.95	\$83.55	\$112.45	\$90.90	\$94.30	\$85.55	\$15.50	\$44.95	\$67.50	\$112.45	\$5.25	\$4.10	\$5.50	\$4.85	\$4.10	\$5.50	\$67.30	
	2033	2.0%	2.0%	0.850	\$75.00	\$102.95	\$83.55	\$114.70	\$92.75	\$96.15	\$87.25	\$15.80	\$45.85	\$68.85	\$114.70	\$5.35	\$4.10	\$5.65	\$4.95	\$4.10	\$5.65	\$68.65	
	2034	2.0%	2.0%	0.850	\$75.00	\$105.00	\$83.55	\$117.00	\$94.60	\$98.10	\$89.00	\$16.10	\$46.75	\$70.20	\$117.00	\$5.45	\$4.10	\$5.75	\$5.05	\$4.10	\$5.75	\$70.00	
	2035	2.0%	2.0%	0.850	\$75.00	\$107.10	\$83.55	\$119.35	\$96.50	\$100.05	\$90.75	\$16.40	\$47.70	\$71.65	\$119.35	\$5.55	\$4.10	\$5.85	\$5.15	\$4.10	\$5.85	\$71.40	
	2036	2.0%	2.0%	0.850	\$75.00	\$109.25	\$83.55	\$121.70	\$98.40	\$102.05	\$92.60	\$16.75	\$48.65	\$73.05	\$121.70	\$5.70	\$4.10	\$5.95	\$5.25	\$4.10	\$5.95	\$72.85	
	2036+	2.0%	2.0%	0.850	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	

- Notes:
- All prices are in Canadian dollars except WTI and NYMEX gas which are in U.S. dollars
  - Edmonton city gate prices based on historical light oil par prices posted by the government of Alberta and Net Energy differential futures (40 Deg. API < 0.5% Sulphur)
  - Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point
  - 1 Mcf is equivalent to 1 mmbtu
  - Real prices listed in 2016 dollars with no escalation considered
  - Alberta gas prices, except AECO, include an average cost of service to the plant gate
  - NGL prices have been switched from a mix reference to a spec reference

Disclaimer - No representation or warranty of any kind (whether expressed or implied) is given by Deloitte LLP as to the accuracy, completeness, currency or fitness for any purpose of this document. As such, this document does not constitute the giving of investment advice, nor a part of any advice on investment decisions. Accordingly, regardless of the form of action, whether in contract, tort or otherwise, and to the extent permitted by applicable law, Deloitte LLP accepts no liability for the consequences of any person acting or refraining from acting in reliance on this price forecast in whole or in part. **This price forecast is not for dissemination in the United States or for distribution to United States wire services.**

## Part 4 Reconciliation of changes in reserves

### Item 4.1 Reserves reconciliation

**Tanager Energy Inc.**  
**NI 51-101 FORECAST CASE**  
**RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL**  
**PRODUCT TYPE**

Effective December 31, 2016

Canada

Opening: Deloitte December 31, 2015 Forecast Pricing

Closing: Deloitte December 31, 2016 Forecast Pricing

	Light & Medium Oil			Heavy Oil			Conventional Gas			Natural Gas Liquids		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	Mstb	Mstb	Mstb
Opening Balance	284.3	413.2	697.5	0.0	0.0	0.0	1,469.4	3,193.6	4,663.0	61.0	132.5	193.5
Production	-2.7	0.0	-2.7	0.0	0.0	0.0	-8.7	0.0	-8.7	-0.4	0.0	-0.4
Technical Revisions	-153.9	-314.1	-468.0	0.0	0.0	0.0	-900.9	-2,796.4	-3,697.2	-38.1	-110.5	-148.6
Extensions & Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-2.4	11.7	9.3	0.0	0.0	0.0	-16.8	133.5	116.6	0.0	0.0	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	125.3	110.8	236.1	0.0	0.0	0.0	543.0	530.7	1,073.7	22.5	22.0	44.6

Effective December 31, 2016

United States

Opening:

Closing: Deloitte December 31, 2016 Forecast Pricing

	Tight Oil			Heavy Oil			Conventional Gas			Natural Gas Liquids		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	Mstb	Mstb	Mstb
Opening Balance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	0.0	0.0	0.0
Extensions & Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	547.6	2,110.2	2,657.8	0.0	0.0	0.0	6,726.3	54,350.8	61,077.1	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	547.6	2,110.2	2,657.8	0.0	0.0	0.0	6,726.3	54,350.8	61,077.1	0.0	0.0	0.0

## Part 5 Additional information relating to reserves data

### Item 5.1 Undeveloped reserves

#### Canada

Probable undeveloped reserves have been assigned to the C1 - 02/05-23-039-26W4/0. This well is currently shut-in but has plans to whipstock in a southeast direction in the Leduc Formation with a forecast on-stream date of July 2018. Last year the location at C5 - LC/00-23-039-26W4/A was assigned proved undeveloped reserves based on the offset well, C1 – 02/05-23-039-26W4/0 but is currently uneconomic.

#### United States

Three immediate PUD offsets and one probable undeveloped offset have been identified to be drilled in the Lower Woodbine. These locations are supported by subsurface mapping and 3D Seismic. The ultimate recoveries for these locations should be analogous to the ultimate recovery calculated for the Cain-Carter #1 and have been estimated at 433 MBOE with an initial rate at 496 BOEPD.

Five Upper Woodbine locations have been identified. Tanager Energy Inc. expects to encounter similar results in the upper Woodbine on their acreage. The ultimate recoveries for all five locations are based on statistical analysis to The Double A Wells Field and tempered by the initial results of the Vision-Blackstone Minerals #1 well which offsets Tanager's acreage position to the north. The ultimate recoveries for each of these wells has been estimated at 2,137 MBOE with an initial rate of 1,245 BOEPD. Two locations will be drilled as directional wells, Cain-Carter #2 & Cain-Carter #3, the other three will be drilled as vertical wells.

### Item 5.2 Significant factors or uncertainties

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

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, commodity 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. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material. Reserve estimates are subject to change with such factors as, updated production data, well performance and operational issues, ongoing development activities, price forecasts, and other economic conditions.

### Item 5.3 Future development costs

Canada				
Year	Undiscounted future costs net (M\$)		Discounted (10%) future costs net (M\$)	
	Proved	Proved + probable	Proved	Proved + probable
2022	46.4	46.4	27.5	27.5
2023	107.0	47.3	57.6	25.5
2024	66.6	66.6	32.6	32.6
2025	225.7	0.00	38.7	0.00
2031	0.00	44.3	0.00	11.1
2032	0.00	71.3	0.00	16.6
2046	0.00	280.6	0.00	16.9
Total	445.6	556.5	156.4	129.8

United States				
Year	Undiscounted future costs net (M\$)		Discounted (10%) future costs net (M\$)	
	Proved	Proved + probable	Proved	Proved + probable
2017	340.4	2,640.9	324.6	2,518.0
2018	2,042.3	3,474.8	1,770.2	3,011.9
2019	2,736.7	4,567.4	2,156.5	3,599.0
2020	0.0	694.4	0.0	497.4
Total	5,119.4	11,377.5	4,251.3	9,626.4

## Part 6 Other oil and gas information

### Item 6.1 Oil and gas properties and wells

#### Canada

##### *Project B and C*

Project B and C are located approximately 10 miles northeast of Red Deer, Alberta in Township 39, Range 26W4.

#### United States

##### *Polk Co, Texas*

The Company's American oil and gas reserves are located in Polk Co, Texas.

#### Geology - Canada

##### **Leduc**

The Late Devonian Leduc Formation is represented by large barrier reef and smaller pinnacle reef bioherms which grew on the Cooking Lake platform carbonates. Trending northeast to southwest, the limestones and dolostones of the Leduc/Cooking Lake Formations were deposited on the bathymetric highs of the Late Devonian seas. Hydrocarbons are trapped by lateral stratigraphic pinch-out of these dolomitic carbonates into deeper water shale sediments.

##### **Horseshoe Canyon/Bearpaw**

The Horseshoe Canyon Formation is part of the Upper Cretaceous Edmonton group which lies unconformably on top of the Belly River Group and is overlain by the tertiary Scollard Formation. Sediments of the Horseshoe Canyon were deposited in a complex coastal environment with shore face sands, tidal channel sands, distributary sands and large back barrier peat bog swamps. The result of such an environment is a stratigraphic section of approximately 100 to 400 metres thick with the lower to middle Horseshoe Canyon containing multiple prospective coal seams and sandstones.

##### **Basal Belly River/Pakowki**

The Upper Cretaceous Basal Belly River/Pakowki Formations represent a marginal marine fluvial/deltaic environment that deposited clastic sediments in series of north-south trending bar sands. Reservoirs are developed in sandstone lobes, and to a lesser extent, channel sands, as river systems supplied sediments to the prograding delta. Gas pools that are developed in deltaic lobe sandstones trapped stratigraphically as the reservoir sands grade laterally into siltstone and shale.

##### **Upper Mannville**

The Early Cretaceous Upper Mannville Group consists of sandstones, siltstones, shales and coals deposited in a fluvial environment in which shorelines and sediments were moving northward. Sandstones of the Upper Mannville contain a significant amount of volcanic and feldspathic material. Hydrocarbons are trapped stratigraphically within porous sandstones that are truncated by tight, lithic Upper Mannville channels in an updip position or as the sandstones pinch-out or grade laterally into the surrounding siltstones and shales.

## Geology – United States

### Upper Woodbine

The lower Woodbine is a slope fan feature and is progradational in nature exhibiting a Bouma type sequence with the coarsest sands at the base then fining up. These sands are discontinuous and lenticular and vary in areal extent.

### Lower Woodbine

The Upper Woodbine is a rich deltaic sequence with abundant sand channels thinning on the edges with tight distal clay choked sands.

#### Item 6.1.2 Gross and net oil and gas wells

Country/Province	Oil		Gas		Non-producing		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Canada</b>								
<b>Alberta</b>	1.0	0.5	0.0	0.0	6.0	2.8	7.0	3.3
<b>United States</b>								
<b>Texas</b>	0.0	0.0	0.0	0.0	1.0	0.5	1.0	0.5
<b>Total</b>	<b>1.0</b>	<b>0.5</b>	<b>0.0</b>	<b>0.0</b>	<b>7.0</b>	<b>3.3</b>	<b>8.0</b>	<b>3.8</b>

#### Item 6.2 Properties with no attributed reserves

##### Canada

The D0/15-22-039-26W4/0 well was forecast to have an initial rate of 30 bbl/d as of the effective date. This rate was based on the average daily rate realized since the well was reactivated in August 2016. Average daily rates have been used to forecast the rate as the field has been experiencing significant operational issues downstream of the well; these issues are expected to be resolved based on discussions with Tanager. Proved developed producing reserves of 22.5 Mstb have been assigned based on production performance prediction. The proved plus probable reserve case assumes the well will realize an initial rate of 30 bbl/d and will recover 60.5 Mstb.

The B2 – 00/10-22-039-26W4/0, B3 – 02/10-22-039-26W4/0, and B4 – 00/14-22-039-26W4/2 oil wells are scheduled to be re-activated in 2017. As with D0/15-22, reserves are based on both overall field production performance as well as a review of the pool's ultimate recovery factor. Proved developed non-producing reserves are assigned to these wells as the wells have demonstrated production over a number of years. The initial production rate of 35 bbl/d for all of these wells are based upon the historical performance as well as the increase in reservoir pressure. In addition, the forecasts for these wells are supported by the reported production for D0/15-22 and increased reservoir pressure.

There is also potential for a CO<sub>2</sub> flood. Other CO<sub>2</sub> floods in nearby fields have shown potential for incremental recoveries ranging from 12 to 25 percent. However, Tanager would need to conduct a study to determine if such an enhanced recovery scheme in this pool would be technically and economically feasible.

Within the Project C, the horizontal well C1 – 02/05-23-039-26W4/0 which was suspended since December 2008, is to be whipstocked in a southeast direction in the Leduc Formation and is estimated to start production July 2018. While proved reserves could be assigned to this well as it has demonstrated production over a number of years, the initial rate and recoverable volumes assigned are not economic. As a result, only probable volumes of 67.1 Mstb have been assigned assuming an initial rate of 35 bbl/d. Overall reserves have been based upon both an analysis of the pool volumetrics as well as a review of the pool's production performance.

The producing gas wells, C2 – 00/05-23-039-26W4/2 and C3 – 03/05-23-039-26W4/0 are currently uneconomic, no reserves have been assigned at this time.

## United States

There are no properties located in the United States with no attributed reserves.

### Item 6.3 Forward contracts

There are no forward contracts applicable to any produced product.

### Item 6.4 Tax Horizon

The Company is expected to begin paying income tax in 2022 based on proved plus probable cash flow economics for the Canadian assets. The Company is expected to begin paying income tax in 2018 based on proved plus probable economics for the American assets.

### Item 6.5 Costs incurred

The following table summarizes Company's property acquisition costs, exploration costs and development costs incurred during the financial year ended December 31, 2016:

<b>Property Acquisitions and Capital Expenditures</b>	
<b>Nature of Cost</b>	<b>Amount (\$)</b>
Property Acquisition Costs	
Proved	-
Unproved	10,794,491
Exploration Costs	787,338
Development Costs	135,856
<b>Total</b>	<b>11,717,685</b>

### Item 6.6 Exploration and development activities

There have been no exploration or development activities by the Company in the last year.

**Item 6.7 Production estimates**

The following table discloses the total working interest volume for 2017 for each product type associated with the first year of the gross proved reserves and gross probable reserves reported in the Deloitte and Rex D. Morris report effective December 31, 2016, based on forecast prices and costs:

<b>Forecast production working interest</b>		
<b>January 1, 2017 - December 31, 2017</b>		
	<b>Proved</b>	<b>Proved + probable</b>
<b>Project B, AB</b>		
Oil (Mbbbl)	12.2	12.9
Gas (MMcf)	50.5	53.2
NGL (Mbbbl)	2.1	2.2
<b>Project C, AB</b>		
Oil (Mbbbl)	0.0	0.0
Gas (MMcf)	0.0	0.0
NGL (Mbbbl)	0.0	0.0
<b>Polk Co, TX</b>		
Oil (Mbbbl)	3.0	13.0
Gas (MMcf)	36.7	304.7
NGL (Mbbbl)	0.0	0.0
<b>Total</b>		
Oil (Mbbbl)	15.2	25.9
Gas (MMcf)	87.2	357.9
NGL (Mbbbl)	2.1	2.2

**Item 6.8 Production history**

The following table summarizes the share of the Company's average daily production, prices received, royalties paid, production expenses, and operating netbacks for the periods indicated:

	<b>Total Company</b>			
	<b>Q1 2016</b>	<b>Q2 2016</b>	<b>Q3 2016</b>	<b>Q4 2016</b>
<b>Volumes</b>				
light oil + NGLs, bopd	13.0	0.0	20.0	11.0
gas, Mcf/d	95.0	34.0	106.0	80.0
Boe/d	29.0	6.0	38.0	25.0
<b>Light Oil and NGLs</b>				
averages, \$/bbl				
price	21.42	0.00	48.94	52.25
<b>Gas</b>				
averages, \$/Mcf				
price	1.10	2.34	1.13	3.85
Royalties paid	2,416	140	25,170	4,749
Operating cost	29,077	8,405	132,717	73,534
Netback \$/Boe	1.08	(2.40)	(16.79)	(4.83)

## **APPENDIX**

**Forward looking statements**

**Reserve definitions**

**Glossary of abbreviations**

**FORM 51-101 F2 Report on Reserves Data by Independent Qualified Reserves Evaluator**

## FORWARD-LOOKING STATEMENTS

Certain statements contained in this Form 51-101F1 constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "potential", "targeting", "intend", "could", "might", "should", "believe", "prospect", "future", "possible", "can", "speculative", "perhaps" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Form 51-101F1 should not be unduly relied upon. These statements speak only as of the date of this Form 51-101F1. The Company does not intend, and does not assume any obligation, to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

Forward-looking information and statements are included throughout this Form 51-101F1 and include, but are not limited to, statements pertaining to the following:

- corporate strategy;
- the Company's reserves;
- estimates of present value or future net cash flow;
- capital expenditure programs, future capital requirements and the timing and method of financing thereof;
- the production of the Company's assets;
- the Company's access to adequate pipeline capacity and third-part infrastructure;
- the performance and characteristics of the Company's oil and natural gas interest;
- the quantity and quality of the Company's oil and natural gas reserves;
- tax horizon and taxability of the Company;
- supply and demand for oil, natural gas liquids and natural gas;
- industry conditions pertaining to the oil and gas industry; and
- abandonment and reclamation costs.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Form 51-101F1:

- general economic conditions in Canada, the United States and globally including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, NGL and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- uncertainties associated with estimating oil and natural gas reserves;
- incorrect assessments of the value of acquisitions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- availability of financing on acceptable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- rights to surface access;
- the need to obtain required approvals from regulatory authorities;

- general business and market conditions; and
- the liquidity and capital resources risks and business risks discussed in the Company's management's discussion and analysis for the years ended December 31, 2016.

These factors should not be considered exhaustive. Statements in respect of "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. With respect to forward-looking statements contained in this Form 51-101F1, the Company has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; condition of general economic, commodity and financial markets; current technology; cash flow; commodity prices; production rates; effects of regulation and environmental and tax laws; future operating costs and the Company's ability to obtain financing on acceptable terms. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Form 51-101F1 in order to provide readers with a more complete perspective on the Company's future operations and prospects. Readers are cautioned that this information may not be appropriate for other purposes.

**The forward-looking statements contained in this Form 51-101F1 are expressly qualified by this cautionary statement.**

#### **ROUNDING**

In certain instances, numbers may not total due to computer-generated rounding.

#### **NON-GAAP MEASURES**

This Form 51-101F1 uses "netback" which does not have standardized meanings prescribed by generally accepted accounting principles and therefore may not be comparable measures to other companies where similar terminology is used. Netback denotes petroleum and natural gas revenue less royalties, operating expenses and transportation and marketing expenses.

## Reserve definitions

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

### Reserve categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and are disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

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

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

Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

### Development and production status

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

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

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

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

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

## SELECTED ABBREVIATIONS

Certain terms and abbreviations used in this document are defined below:

"bbl"	barrel of oil or NGL;
"bcf"	billion cubic feet of natural gas;
"bpd"	barrel of oil or NGL per day;
"Boe"	barrel of oil equivalent determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel;
"Boe/d"	barrel of oil equivalent per day;
"Mbbbl"	thousand barrels;
"MBoe"	thousand barrels of oil equivalent;
"Mcf"	thousand cubic feet of natural gas;
"Mcf <sub>e</sub> "	Mcf of gas equivalent determined by converting a volume of oil or NGL to Mcf using the ratio of 0.1667 barrels to 1 Mcf;
"Mcf/d"	thousand cubic feet of natural gas per day;
"MMcf"	million cubic feet of natural gas;
"MMcf/d"	million cubic feet of natural gas per day;
"Mstb"	thousand stock tank barrels;
"NGLs"	natural gas liquids;
"\$US"	United States dollar;
"\$Cdn"	Canadian dollar.

### Conversion

In this document measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions.

To convert from:	To:	Multiply by:
Mcf	cubic metres	28.174
Cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	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

In this Form 51-101F1, the calculation of barrels of Boe is calculated at a conversion rate of 6 Mcf for one bbl based on an energy equivalency conversion method. 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 to the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas 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.