FORM 51-101 F1

Tanager Energy Inc.

Statement of reserves data

and other oil and gas information

as of December 31, 2015

Prepared by Deloitte

February 8, 2016

Table of contents

Part 1 Date of statement

Date of statement:	February 5, 2016
Effective date:	December 31, 2015
Preparation date:	February 8, 2016

Tanager Energy Inc.'s (the Company) oil and gas reserves were evaluated by Deloitte LLP (Deloitte), effective December 31, 2015. 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").*

All of the Company's oil and gas reserves are located ten miles northeast of Red Deer, Alberta in section 22, township 39, range 26 W4M.

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, 2015 Forecast Pricing (CAD)

Effective December 31, 2015 Canada

VOLUMES IN IMPERIAL UNITS

	Oil						Natural Gas											
	Light/Medium Crude		Heavy Crude		Bitumen		Solution		Conventional		Coalbed Methane		Natural Gas Liquids		Sulphur		Total BOE	
CATEGORY	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net
	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	Mstb	Mstb	Mlt	Mlt	Mboe	Mboe
PDP	18.2	14.2	0.0	0.0	0.0	0.0	49.6	38.5	0.0	0.0	0.0	0.0	2.1	1.2	0.2	0.1	28.6	21.8
PDNP	225.8	142.1	0.0	0.0	0.0	0.0	977.5	689.2	0.0	0.0	0.0	0.0	40.6	23.9	3.8	2.8	429.3	280.9
PUD	40.2	33.9	0.0	0.0	0.0	0.0	442.3	372.7	0.0	0.0	0.0	0.0	18.4	15.5	1.7	1.5	132.3	111.5
TP	284.3	190.2	0.0	0.0	0.0	0.0	1,469.4	1,100.4	0.0	0.0	0.0	0.0	61.0	40.5	5.7	4.4	590.2	414.2
PB	413.2	269.5	0.0	0.0	0.0	0.0	3,193.6	2,508.8	0.0	0.0	0.0	0.0	132.5	102.6	12.5	10.1	1,078.0	790.2
P+P	697.5	459.7	0.0	0.0	0.0	0.0	4,663.0	3,609.1	0.0	0.0	0.0	0.0	193.5	143.1	18.2	14.5	1,668.2	1,204.4

VOLUMES IN METRIC UNITS

	Oil						Natural Gas											
	Light/Medium Crude		Heavy Crude		Bitumen		Solution		Conventional		Coalbed Methane		Natural Gas Liquids		Sulphur		Total BOE	
CATEGORY	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net	W.I Gross	Co. Share Net
	E3m3	E3m3	E3m3	E3m3	E3m3	E3m3	E6m3	E6m3	E6m3	E6m3	E6m3	E6m3	E3m3	E3m3	E3t	E3t	E3m3e	E3m3e
PDP	2.9	2.3	0.0	0.0	0.0	0.0	1.4	1.1	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.1	4.5	3.5
PDNP	35.9	22.6	0.0	0.0	0.0	0.0	27.5	19.4	0.0	0.0	0.0	0.0	6.4	3.8	3.9	2.8	68.2	44.6
PUD	6.4	5.4	0.0	0.0	0.0	0.0	12.5	10.5	0.0	0.0	0.0	0.0	2.9	2.5	1.8	1.5	21.0	17.7
TP	45.2	30.2	0.0	0.0	0.0	0.0	41.4	31.0	0.0	0.0	0.0	0.0	9.7	6.4	5.8	4.4	93.8	65.8
PB	65.7	42.8	0.0	0.0	0.0	0.0	90.0	70.7	0.0	0.0	0.0	0.0	21.1	16.3	12.7	10.3	171.3	125.6
P+P	110.8	73.1	0.0	0.0	0.0	0.0	131.4	101.7	0.0	0.0	0.0	0.0	30.8	22.7	18.5	14.7	265.1	191.4

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

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, 2015 Forecast Pricing (CAD)

Effective: December 31, 2015 **Canada**

BOE

	Before Income Taxes					After Income Taxes					
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	10% BTAX
RESERVES CATEGORY	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	$/boe*
Proved Developed Producing	-145.8	-21.0	32.6	55.8	65.5	-145.8	-21.0	32.6	55.8	65.5	1.49
Proved Developed Non-Producing	3,579.6	2,465.6	1,721.9	1,207.0	839.2	3,128.9	2,171.0	1,523.6	1,070.1	742.4	6.13
Proved Undeveloped	1,799.3	1,285.4	937.8	697.3	527.4	1,348.3	965.1	705.6	525.9	398.8	8.41
Total Proved	5,233.1	3,730.0	2,692.3	1,960.1	1,432.1	4,331.4	3,115.2	2,261.9	1,651.7	1,206.6	6.50
Probable	15,596.5	10,150.0	6,972.2	4,998.7	3,709.3	11,743.9	7,647.2	5,259.6	3,778.6	2,811.7	8.82
Total Proved + Probable	20,829.5	13,880.0	9,664.5	6,958.8	5,141.4	16,075.3	10,762.3	7,521.5	5,430.3	4,018.3	8.02

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, 2015 Forecast Pricing

Effective December 31, 2015 **Canada**

Category	Revenue	Royalties	Operating Costs	Investment Costs	Well Abandonment Costs	Future Net Revenue Before Income Tax	Income Taxes	Future Net Revenue After Income Tax
	M$	M$	M$	M$	M$	M$	M$	M$
Proved Developed Producing	1,014.1	212.2	568.5	0.0	379.2	-145.8	0.0	-145.8
Proved Developed Non-producing	18,967.3	6,326.7	8,161.0	900.0	0.0	3,579.6	450.7	3,128.9
Proved Undeveloped	6,454.5	1,253.8	3,314.5	0.0	86.9	1,799.3	451.0	1,348.3
Total Proved	26,436.0	7,792.7	12,044.1	900.0	466.1	5,233.1	901.7	4,331.4
Probable	53,115.9	15,852.9	21,633.8	0.0	32.8	15,596.5	3,852.6	11,743.9
Total Proved + Probable	79,551.9	23,645.6	33,677.8	900.0	498.9	20,829.5	4,754.2	16,075.3

Tanager Energy Inc.
NI 51-101 FORECAST CASE
FUTURE NET REVENUE BY PRODUCT TYPE
Deloitte December 31, 2015 Forecast Pricing (CAD)

Effective December 31, 2015 **Canada**

	Btax NPV @ 10% M$	Unit Value $/Primary product
TOTAL PROVED		
Light and Medium Crude Oil (including solution gas and by-products)	2,776.3	14.59 $/bbl
Conventional Natural Gas (including by-products but excluding solution and gas and by-products from oil wells)	-83.9	$0.00 $/Mcf
Total	2,692.3	$6.50 $/boe
TOTAL PROVED + PROBABLE		
Light and Medium Crude Oil (including solution gas and by-products)	9,748.4	21.20 $/bbl
Conventional Natural Gas (including by-products but excluding solution and gas and by-products from oil wells)	-83.9	0.00 $/Mcf
Total	9,664.5	8.02 $/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, 2015 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 2015

					Crude Oil Pricing							Natural Gas Liquids Pricing Edmonton Par Prices				Natural Gas Pricing						Sulphur
		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	WTI at Cushing Oklahoma US$/bbl Real	WTI at Cushing Oklahoma US$/bbl Current	Edmonton City Gate C$/bbl Real	Edmonton City Gate C$/bbl Current	WCS 20.5 Deg. API Hardisty C$/bbl Current	Bow River 25 Deg. API Hardisty C$/bbl Current	Heavy Oil 12 Deg. API Hardisty C$/bbl Current	Ethane C$/bbl Current	Propane C$/bbl Current	Butane C$/bbl Current	Pentanes + Condensate C$/bbl Current	Alberta Reference Average Price C$/mcf Current	Alberta AECO Average Price C$/mcf Real	Alberta AECO Average Price C$/mcf Current	B.C. Direct Stn. 2 Sales C$/mcf Current	NYMEX Henry Hub US$/Mcf Real	NYMEX Henry Hub US$/Mcf Current	Alberta Plant Gate C$/lt Current
H	2005	2.2%	2.2%	0.826	$67.93	$56.56	$83.21	$69.29	$44.60	$45.62	$33.70	$23.78	$43.19	$51.88	$74.72	$8.30	$10.53	$8.76	$8.22	$10.58	$8.81	$40.99
i	2006	2.0%	2.0%	0.882	$77.51	$66.02	$86.04	$73.28	$51.22	$51.90	$39.53	$19.83	$44.07	$58.16	$78.18	$6.56	$7.68	$6.54	$6.58	$7.92	$6.75	$19.53
s	2007	2.1%	2.1%	0.935	$83.19	$72.32	$88.64	$77.05	$52.90	$53.87	$39.76	$18.42	$49.75	$59.35	$81.64	$6.20	$7.42	$6.45	$6.40	$8.03	$6.98	$38.02
t	2008	2.4%	2.4%	0.943	$112.10	$99.57	$115.73	$102.80	$82.95	$83.90	$73.08	$22.59	$56.96	$83.54	$109.82	$7.88	$9.18	$8.16	$8.20	$9.98	$8.86	$303.83
o	2009	0.3%	0.3%	0.880	$67.76	$61.65	$72.64	$66.10	$58.66	$59.80	$54.40	$11.61	$34.62	$56.21	$69.52	$3.85	$4.35	$3.96	$4.17	$4.34	$3.95	($5.08)
r	2010	1.8%	1.8%	0.971	$86.99	$79.40	$85.25	$77.80	$67.22	$68.18	$60.62	$11.53	$45.19	$68.79	$84.06	$3.76	$4.39	$4.01	$4.01	$4.81	$4.39	$56.94
i	2011	2.9%	2.9%	1.012	$102.13	$94.88	$102.84	$95.54	$77.12	$78.42	$69.60	$10.30	$52.41	$86.98	$105.29	$3.46	$3.91	$3.63	$3.34	$4.31	$4.00	$101.60
c	2012	1.5%	1.5%	1.001	$98.34	$94.11	$90.47	$86.57	$73.10	$74.41	$64.07	$6.73	$30.80	$75.47	$99.71	$2.25	$2.50	$2.39	$2.29	$2.88	$2.75	$126.81
a	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	$103.57	$2.98	$3.27	$3.17	$3.11	$3.84	$3.73	$62.17
l	2014	1.9%	1.9%	0.906	$95.07	$93.26	$95.82	$94.00	$81.06	$81.49	$73.70	$12.46	$38.38	$57.08	$100.95	$4.22	$4.59	$4.50	$4.16	$4.48	$4.39	$88.99
2	12 Mths H	1.2%	1.2%	0.783	$48.68	$48.68	$57.09	$57.09	$44.97	$45.46	$40.44	$7.50	$1.62	$24.69	$53.62	$2.52	$2.69	$2.69	$1.81	$2.63	$2.63	$103.86
0	0 Mths F	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1																						
5	Avg.	N/A	N/A	0.783	$48.68	$48.68	$57.09	$57.09	$44.97	$45.46	$40.44	$7.50	$1.62	$24.69	$53.62	$2.52	$2.69	$2.69	$1.81	$2.63	$2.63	$103.86
F	2016	0.0%	0.0%	0.740	$42.00	$42.00	$51.35	$51.35	$37.35	$38.35	$31.35	$6.75	$5.15	$20.55	$51.35	$2.25	$2.45	$2.45	$1.70	$2.40	$2.40	$100.00
o	2017	2.0%	2.0%	0.770	$47.50	$48.45	$56.50	$57.65	$43.35	$44.35	$37.25	$7.85	$11.55	$28.80	$57.65	$2.65	$2.80	$2.85	$2.35	$2.75	$2.80	$102.00
r	2018	2.0%	2.0%	0.800	$55.00	$57.20	$63.75	$66.35	$51.75	$52.80	$45.50	$8.60	$19.90	$39.80	$66.35	$2.90	$3.00	$3.10	$2.60	$3.00	$3.10	$104.05
e	2019	2.0%	2.0%	0.800	$62.50	$66.35	$73.15	$77.65	$62.75	$63.85	$56.40	$9.50	$23.30	$46.60	$77.65	$3.25	$3.25	$3.45	$2.90	$3.20	$3.40	$106.10
c	2020	2.0%	2.0%	0.800	$70.00	$75.75	$82.50	$89.30	$74.15	$75.25	$67.65	$10.30	$26.80	$53.60	$89.30	$3.50	$3.45	$3.75	$3.20	$3.35	$3.65	$108.25
a	2021	2.0%	2.0%	0.800	$75.00	$82.80	$88.75	$98.00	$82.55	$83.65	$75.90	$11.35	$29.40	$58.80	$98.00	$3.90	$3.75	$4.15	$3.60	$3.60	$3.95	$110.40
s	2022	2.0%	2.0%	0.800	$80.00	$90.10	$95.00	$107.00	$91.20	$92.35	$84.45	$12.10	$32.10	$64.20	$107.00	$4.15	$3.90	$4.40	$3.85	$3.70	$4.15	$112.60
t	2023	2.0%	2.0%	0.800	$80.00	$91.90	$95.00	$109.15	$93.05	$94.20	$86.15	$12.80	$32.75	$65.50	$109.15	$4.40	$4.05	$4.65	$4.10	$3.85	$4.40	$114.85
	2024	2.0%	2.0%	0.800	$80.00	$93.75	$95.00	$111.30	$94.90	$96.10	$87.85	$13.70	$33.40	$66.80	$111.30	$4.75	$4.25	$5.00	$4.40	$4.00	$4.70	$117.15
	2025	2.0%	2.0%	0.800	$80.00	$95.60	$95.00	$113.55	$96.80	$98.00	$89.65	$14.15	$34.05	$68.10	$113.55	$4.90	$4.30	$5.15	$4.55	$4.05	$4.85	$119.50
	2026	2.0%	2.0%	0.800	$80.00	$97.50	$95.00	$115.80	$98.75	$99.95	$91.40	$15.10	$34.75	$69.50	$115.80	$5.25	$4.50	$5.50	$4.90	$4.20	$5.10	$121.90
	2027	2.0%	2.0%	0.800	$80.00	$99.45	$95.00	$118.10	$100.70	$101.95	$93.25	$15.90	$35.45	$70.85	$118.10	$5.55	$4.65	$5.80	$5.15	$4.30	$5.35	$124.35
	2028	2.0%	2.0%	0.800	$80.00	$101.45	$95.00	$120.50	$102.75	$104.00	$95.10	$16.25	$36.15	$72.30	$120.50	$5.65	$4.65	$5.90	$5.25	$4.30	$5.45	$126.80
	2029	2.0%	2.0%	0.800	$80.00	$103.50	$95.00	$122.90	$104.80	$106.10	$97.00	$16.55	$36.85	$73.75	$122.90	$5.75	$4.65	$6.00	$5.35	$4.30	$5.55	$129.35
	2030	2.0%	2.0%	0.800	$80.00	$105.55	$95.00	$125.35	$106.90	$108.20	$98.95	$16.90	$37.60	$75.20	$125.35	$5.85	$4.65	$6.15	$5.50	$4.30	$5.65	$131.95
	2031	2.0%	2.0%	0.800	$80.00	$107.65	$95.00	$127.85	$109.00	$110.35	$100.95	$17.25	$38.35	$76.70	$127.85	$6.00	$4.65	$6.25	$5.60	$4.30	$5.80	$134.60
	2032	2.0%	2.0%	0.800	$80.00	$109.80	$95.00	$130.40	$111.20	$112.55	$102.95	$17.55	$39.10	$78.25	$130.40	$6.10	$4.65	$6.40	$5.70	$4.30	$5.90	$137.30
	2033	2.0%	2.0%	0.800	$80.00	$112.00	$95.00	$133.00	$113.40	$114.80	$105.00	$17.90	$39.90	$79.80	$133.00	$6.25	$4.65	$6.50	$5.80	$4.30	$6.00	$140.00
	2034	2.0%	2.0%	0.800	$80.00	$114.25	$95.00	$135.70	$115.70	$117.10	$107.10	$18.30	$40.70	$81.40	$135.70	$6.35	$4.65	$6.65	$5.95	$4.30	$6.15	$142.80
	2035	2.0%	2.0%	0.800	$80.00	$116.55	$95.00	$138.40	$118.00	$119.45	$109.25	$18.65	$41.50	$83.05	$138.40	$6.50	$4.65	$6.75	$6.05	$4.30	$6.25	$145.70
	2035+	2.0%	2.0%	0.800	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	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 2015 dollars with no escalation considered
- Alberta gas prices, except AECO, include an average cost of service to the plant gate

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, 2015 **Canada**

Opening: Deloitte December 31, 2014 Forecast Pricing Closing: Deloitte December 31, 2015 Forecast Pricing

	Light & Medium Oil			Heavy Oil			Conventional Gas			Coalbed Methane			Natural Gas Liquids		
	Proved	Probable	Proved + Probable	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	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	0.0	0.0	0.0
Production	-2.9	0.0	-2.9	0.0	0.0	0.0	-7.7	0.0	-7.7	0.0	-2.9	0.0	-0.3	0.0	-0.3
Technical Revisions	269.3	336.7	606.0	0.0	0.0	0.0	1,280.0	2,352.2	3,632.2	336.7	606.0	0.0	53.1	97.6	150.7
Extensions & Improved Recovery	17.9	76.5	94.4	0.0	0.0	0.0	197.2	841.4	1,038.5	76.5	94.4	0.0	8.2	34.9	43.1
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	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	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	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	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	0.0	0.0	0.0
Closing Balance	284.3	413.2	697.5	0.0	0.0	0.0	1,469.4	3,193.6	4,663.0	413.2	697.5	0.0	61.0	132.5	193.5

Part 5 Additional information relating to reserves data

Item 5.1 Undeveloped reserves

Proved undeveloped and proved plus probable undeveloped reserves have been assigned to a location producing from the Leduc Formation with an on-stream date of August 2018. The reserves for the location C5 – LC/00-23-039-26W4/A, are based on the offset producing well, C1 – 02/05-23-039-26W4/0.

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

	Undiscounted future costs net (M$)		Discounted (10%) future costs net (M$)	
Year	Proved	Proved + probable	Proved	Proved + probable
2016	900.0	900.0	872.17	872.17
Total	900.0	900.0	872.17	872.17

Capital expenditures forecast for pumpjack installation in early 2016 to enhance performance, well re-entry and re-activation, whipstock well to bring back on production and also drill, complete and tie-in.

Part 6 Other oil and gas information

Item 6.1 Oil and gas properties and wells

Project B and C

Project B and C are located approximately 10 miles northeast of Red Deer, Alberta in Township 39, Range 26W4. The Corporation's non-operating interest in the Property is as follows:

Project B					
B1 - D0/15-22-039-26W4/0	Leduc Formation	Oil Light	BPO: (2018-10-01) 50% WI APO: 1: 50% WI	Crown	13.2688% GORR 9.5612% GORR
B2 - 00/10-22-039-26W4/0	Leduc Formation	Oil Light	BPO: (2017-08-25) 50% WI APO: 1: 50% WI	Crown	13.2688% GORR 9.5612% GORR
B3 - 02/10-22-039-26W4/0	Leduc Formation	Oil Light	BPO: (2017-11-14) 50% WI APO: 1: 50% WI	Crown	13.2688% GORR 9.5612% GORR
B4 - 00/14-22-039-26W4/2	Leduc Formation	Oil Light	BPO: (2017-09-21) 50% WI APO: 1: 50% WI	Crown	13.2688% GORR 9.5612% GORR

Project C				
C1 - 02/05-23-039-26W4/0	Leduc Formation SUSP OIL	Oil Light	BPO: (Capital) APO: 1: 32% WI	Freehold 15.75% Manual
C2 - 00/05-23-039-26W4/2	Glauconitic Sandstone FLOWING GAS	Gas Conventional	39.7544% WI+0.38% GORI	Crown on 0.3%+FH 16.219% on 99.7%
C3 - 03/05-23-039-26W4/0	Horseshoe Canyon Formation FLOWING	Gas Conventional	39.7544% WI+0.38% GORI	Crown on 0.3%+FH 16.219% on 99.7%
C4 - 02/12-26-039-26W4/0	Basal Belly River DRILLED & CASED	Gas Conventional	55% WI	Freehold 15% Manual
C5 - LC/00-23-039-26W4/A	Leduc Formation	Oil Light	BPO: (Capital) APO: 1: 32% WI	Freehold 15.75% Manual

Geology

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 m 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.

Economic summary

The following table from the Deloitte report presents an economic summary.

Tanager Energy Inc.
DETAILED ECONOMIC SUMMARY
Deloitte December 31, 2015 Forecast Pricing (CAD)
Canada

Effective December 31, 2015

	PDP	PDNP	PD	PUD	TP	P+PBP	P+PBNP	P+PBD	P+PBUD	P+P
Light and Medium Oil — Mbbl										
Ultimate Remaining	36.5	451.6	488.1	237.0	725.1	73.4	817.9	891.3	737.4	1,905.3
WI Before Royalty	18.2	225.8	244.1	40.2	284.3	36.7	408.9	445.6	182.4	697.5
WI After Royalty	14.2	142.1	156.4	33.9	190.2	26.9	220.7	247.6	153.7	459.7
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	14.2	142.1	156.4	33.9	190.2	26.9	220.7	247.6	153.7	459.7
Total Oil — Mbbl										
Ultimate Remaining	36.5	451.6	488.1	237.0	725.1	73.4	817.9	891.3	737.4	1,905.3
WI Before Royalty	18.2	225.8	244.1	40.2	284.3	36.7	408.9	445.6	182.4	697.5
WI After Royalty	14.2	142.1	156.4	33.9	190.2	26.9	220.7	247.6	153.7	459.7
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	14.2	142.1	156.4	33.9	190.2	26.9	220.7	247.6	153.7	459.7
Sales Gas — MMcf										
Ultimate Remaining	99.2	1,955.0	2,054.2	2,606.5	4,660.7	199.6	3,586.4	3,786.1	8,110.6	14,938.9
WI Before Royalty	49.6	977.5	1,027.1	442.3	1,469.4	99.8	1,793.2	1,893.0	2,006.5	4,663.0
WI After Royalty	38.5	689.2	727.7	372.7	1,100.4	77.8	1,197.6	1,275.5	1,690.5	3,609.1
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	38.5	689.2	727.7	372.7	1,100.4	77.8	1,197.6	1,275.5	1,690.5	3,609.1
NGLs — Mbbl										
Ultimate Remaining	4.1	81.1	85.2	108.2	193.4	8.3	148.8	157.1	336.6	620.0
WI Before Royalty	2.1	40.6	42.6	18.4	61.0	4.1	74.4	78.6	83.3	193.5
WI After Royalty	1.2	23.9	25.0	15.5	40.5	2.4	43.8	46.2	70.2	143.1
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	1.2	23.9	25.0	15.5	40.5	2.4	43.8	46.2	70.2	143.1
Sulphur — Mlt										
Ultimate Remaining	0.4	7.6	8.0	10.2	18.2	0.8	14.0	14.8	31.6	58.3
WI Before Royalty	0.2	3.8	4.0	1.7	5.7	0.4	7.0	7.4	7.8	18.2
WI After Royalty	0.1	2.8	2.9	1.5	4.4	0.3	5.1	5.4	6.6	14.5
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	0.1	2.8	2.9	1.5	4.4	0.3	5.1	5.4	6.6	14.5
BOE — Mboe										
Ultimate Remaining	57.1	858.6	915.7	779.6	1,695.3	115.0	1,564.4	1,679.4	2,425.8	5,015.1
WI Before Royalty	28.6	429.3	457.9	132.3	590.2	57.5	782.2	839.7	600.1	1,668.2
WI After Royalty	21.8	280.9	302.7	111.5	414.2	42.3	464.1	506.4	505.6	1,204.4
Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net	21.8	280.9	302.7	111.5	414.2	42.3	464.1	506.4	505.6	1,204.4
NPV - BTAX — M$										
Undiscounted	-145.8	3,579.6	3,433.8	1,799.3	5,233.1	401.3	6,289.3	6,690.6	9,141.1	20,829.5
Discounted at 5%	-21.0	2,465.6	2,444.7	1,285.4	3,730.0	395.0	4,274.4	4,669.4	6,422.0	13,880.0
Discounted at 10%	32.6	1,721.9	1,754.5	937.8	2,692.3	356.8	2,997.8	3,354.6	4,643.7	9,664.5
Discounted at 12%	44.3	1,494.1	1,538.3	831.2	2,369.5	339.6	2,618.7	2,958.3	4,108.7	8,444.7
Discounted at 15%	55.8	1,207.0	1,262.8	697.3	1,960.1	314.1	2,149.7	2,463.8	3,444.2	6,958.8

The following tables from the Deloitte report present the cash flow before tax and after tax:

Discounted Cash Flow
Deloitte December 31, 2015 Forecast Pricing (CAD)

Total Proved Reserves

Cash Flow BTAX

	Company Revenue M$	Crown Royalty M$	Freehold Royalty M$	ORR Royalty M$	Mineral Tax M$	Total Royalty Burden %	Net Rev After Royalties M$	Other Income M$	Sask Corp Cap Tax M$	Fixed Oper Expense M$	Variable Operating Expense M$	Other Expenses M$	Total Operating Costs M$	Abandon Cost & Salvage M$	Net Operating Income M$	Total Investment M$	NET Cash Flow M$	CUM Cash Flow M$	Disc Cash Flow (10%)
2016	1,727	386.2	0.0	219.2	0.0	35	1,121	0.0	0.0	113.9	876.1	0.0	990.0	0.0	132	900.0	-768	-768	-748
2017	2,573	615.0	0.0	309.3	0.0	36	1,648	0.0	0.0	168.3	1,144.0	0.0	1,312.3	42.6	294	0.0	294	-475	255
2018	2,400	618.4	0.0	229.9	0.0	35	1,552	0.0	0.0	171.7	909.7	0.0	1,081.4	60.1	411	0.0	411	-64	324
2019	2,254	610.4	0.0	209.8	0.0	36	1,434	0.0	0.0	175.1	727.6	0.0	902.7	0.0	531	0.0	531	467	380
2020	2,751	561.9	102.0	193.9	36.5	33	1,856	0.0	0.0	201.0	917.4	0.0	1,118.4	0.0	738	0.0	738	1,205	481
2021	3,238	473.1	214.8	170.6	71.6	29	2,308	0.0	0.0	239.4	1,106.3	0.0	1,345.7	0.0	962	0.0	962	2,166	569
2022	2,671	384.8	175.0	142.7	51.3	28	1,918	0.0	0.0	195.2	850.5	0.0	1,045.7	0.0	872	0.0	872	3,038	469
2023	2,138	276.8	134.6	117.7	35.5	26	1,573	0.0	0.0	199.1	665.8	0.0	864.9	60.3	648	0.0	648	3,686	317
2024	1,724	190.5	104.5	97.6	25.4	24	1,306	0.0	0.0	203.1	523.1	0.0	726.2	0.0	580	0.0	580	4,266	258
2025	1,370	133.0	79.4	79.8	17.8	23	1,060	0.0	0.0	207.2	409.4	0.0	616.5	0.0	443	0.0	443	4,709	179
Sub	22,845	4,250.3	810.2	1,770.5	238.1	31	15,776	0.0	0.0	1,873.9	8,129.9	0.0	10,003.8	163.0	5,609	900.0	4,709	4,709	2,485
Rem	3,591	285.8	171.5	232.3	34.0	20	2,867	0.0	0.0	1,032.3	1,008.0	0.0	2,040.3	303.2	524	0.0	524	5,233	207
Total	26,436	4,536.1	981.8	2,002.8	272.1	29	18,643	0.0	0.0	2,906.2	9,137.9	0.0	12,044.1	466.1	6,133	900.0	5,233	5,233	2,692

Cash Flow ATAX

	Income Before Tax Loss M$	Tax Loss Generated M$	Tax Loss Claim M$	Federal Taxable Income M$	Basic Federal Tax M$	Federal M&P Tax Credit M$	Federal Surtax M$	Invest Tax Credit M$	Federal Income Tax M$	Attributed Royalty Income M$	Provincial Taxable Income M$	Basic Provincial Tax M$	Provincial M&P Tax Credit M$	Provincial Income Tax M$	Total Income Tax M$	BTAX Cash Flow M$	ATAX Cash Flow M$	CUM Cash Flow M$	Disc Cash Flow (10%) M$
2016	-541.3	541.3	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	-768	-768	-768	-748
2017	-295.5	295.5	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	294	294	-475	255
2018	-11.6	11.6	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	411	411	-64	324
2019	228.0	0.0	228.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	531	531	467	380
2020	520.4	0.0	520.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	738	738	1,205	481
2021	805.4	0.0	100.1	705.3	105.8	0.0	0.0	0.0	105.8	0.0	705.3	70.5	0.0	70.5	176.3	962	786	1,990	465
2022	759.2	0.0	0.0	759.2	113.9	0.0	0.0	0.0	113.9	0.0	759.2	75.9	0.0	75.9	189.8	872	682	2,672	367
2023	566.8	0.0	0.0	566.8	85.0	0.0	0.0	0.0	85.0	0.0	566.8	56.7	0.0	56.7	141.7	648	506	3,178	248
2024	521.2	0.0	0.0	521.2	78.2	0.0	0.0	0.0	78.2	0.0	521.2	52.1	0.0	52.1	130.3	580	449	3,628	200
2025	401.1	0.0	0.0	401.1	60.2	0.0	0.0	0.0	60.2	0.0	401.1	40.1	0.0	40.1	100.3	443	343	3,971	139
Sub	2,953.6	848.4	848.4	2,953.6	443.0	0.0	0.0	0.0	443.0	0.0	2,953.6	295.4	0.0	295.4	738.4	4,709	3,971	3,971	2,111
Rem	411.8	259.7	18.5	653.0	98.0	0.0	0.0	0.0	98.0	0.0	653.0	65.3	0.0	65.3	163.3	524	360	4,331	151
Total	3,365.4	1,108.2	866.9	3,606.6	541.0	0.0	0.0	0.0	541.0	0.0	3,606.6	360.7	0.0	360.7	901.7	5,233	4,331	4,331	2,262

Total Proved Plus Probable Reserves

Cash Flow BTAX

	Company Revenue M$	Crown Royalty M$	Freehold Royalty M$	ORR Royalty M$	Mineral Tax M$	Total Royalty Burden %	Net Rev After Royalties M$	Other Income M$	Sask Corp Cap Tax M$	Fixed Oper Expense M$	Variable Operating Expense M$	Other Expenses M$	Total Operating Costs M$	Abandon Cost & Salvage M$	Net Operating Income M$	Total Investment M$	NET Cash Flow M$	CUM Cash Flow M$	Disc Cash Flow (10%) M$
2016	2,841	801.3	0.0	360.7	0.0	41	1,679	0.0	0.0	113.9	1,435.4	0.0	1,549.3	0.0	130	900.0	-770	-770	-749
2017	4,616	1,406.1	0.0	554.0	0.0	42	2,656	0.0	0.0	168.3	2,062.5	0.0	2,230.8	42.6	383	0.0	383	-387	331
2018	4,361	1,401.2	0.0	413.9	0.0	42	2,546	0.0	0.0	171.7	1,667.1	0.0	1,838.7	60.1	647	0.0	647	260	511
2019	4,832	1,398.3	112.4	379.9	46.1	40	2,895	0.0	0.0	183.6	1,746.6	0.0	1,930.1	0.0	965	0.0	965	1,225	691
2020	9,055	1,320.7	798.5	351.5	325.7	31	6,258	0.0	0.0	234.7	3,668.1	0.0	3,902.8	0.0	2,355	0.0	2,355	3,580	1,534
2021	8,832	1,170.5	847.0	303.8	344.5	30	6,166	0.0	0.0	191.4	3,356.9	0.0	3,548.2	0.0	2,618	0.0	2,618	6,198	1,550
2022	8,088	993.7	795.0	268.4	319.8	29	5,711	0.0	0.0	195.2	2,880.5	0.0	3,075.7	0.0	2,636	0.0	2,636	8,834	1,419
2023	6,666	746.7	656.0	221.4	259.3	28	4,783	0.0	0.0	199.1	2,341.8	0.0	2,540.9	60.3	2,182	0.0	2,182	11,016	1,068
2024	5,547	561.0	547.8	183.6	212.1	27	4,042	0.0	0.0	203.1	1,913.6	0.0	2,116.7	0.0	1,926	0.0	1,926	12,942	856
2025	4,547	418.9	449.9	150.2	169.3	26	3,358	0.0	0.0	207.2	1,559.8	0.0	1,766.9	0.0	1,591	0.0	1,591	14,533	643
Sub	59,385	10,218.5	4,206.5	3,187.4	1,676.8	32	40,096	0.0	0.0	1,868.1	22,632.2	0.0	24,500.2	163.0	15,433	900.0	14,533	14,533	7,855
Rem	20,167	943.5	2,195.9	549.4	667.6	22	15,810	0.0	0.0	2,301.1	6,876.5	0.0	9,177.6	335.9	6,297	0.0	6,297	20,830	1,810
Total	79,552	11,162.0	6,402.4	3,736.8	2,344.3	30	55,906	0.0	0.0	4,169.2	29,508.7	0.0	33,677.8	498.9	21,730	900.0	20,830	20,830	9,664

Cash Flow ATAX

	Income Before Tax Loss M$	Tax Loss Generated M$	Tax Loss Claim M$	Federal Taxable Income M$	Basic Federal Tax M$	Federal M&P Tax Credit M$	Federal Surtax M$	Invest Tax Credit M$	Federal Income Tax M$	Attributed Royalty Income M$	Provincial Taxable Income M$	Basic Provincial Tax M$	Provincial M&P Tax Credit M$	Provincial Income Tax M$	Total Income Tax M$	BTAX Cash Flow M$	ATAX Cash Flow M$	CUM Cash Flow M$	Disc Cash Flow (10%) M$
2016	-542.7	542.7	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	-770	-770	-770	-749
2017	-206.5	206.5	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	383	383	-387	331
2018	225.0	0.0	225.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	647	647	260	511
2019	662.0	0.0	524.2	137.8	20.7	0.0	0.0	0.0	20.7	0.0	137.8	13.8	0.0	13.8	34.4	965	930	1,190	667
2020	2,137.8	0.0	0.0	2,137.8	320.7	0.0	0.0	0.0	320.7	0.0	2,137.8	213.8	0.0	213.8	534.4	2,355	1,821	3,011	1,186
2021	2,461.7	0.0	0.0	2,461.7	369.3	0.0	0.0	0.0	369.3	0.0	2,461.7	246.2	0.0	246.2	615.4	2,618	2,003	5,014	1,186
2022	2,523.2	0.0	0.0	2,523.2	378.5	0.0	0.0	0.0	378.5	0.0	2,523.2	252.3	0.0	252.3	630.8	2,636	2,005	7,019	1,079
2023	2,100.5	0.0	0.0	2,100.5	315.1	0.0	0.0	0.0	315.1	0.0	2,100.5	210.0	0.0	210.0	525.1	2,182	1,657	8,676	811
2024	1,867.2	0.0	0.0	1,867.2	280.1	0.0	0.0	0.0	280.1	0.0	1,867.2	186.7	0.0	186.7	466.8	1,926	1,459	10,135	649
2025	1,549.0	0.0	0.0	1,549.0	232.3	0.0	0.0	0.0	232.3	0.0	1,549.0	154.9	0.0	154.9	387.2	1,591	1,204	11,339	487
Sub	12,777.1	749.2	749.2	12,777.1	1,916.6	0.0	0.0	0.0	1,916.6	0.0	12,777.1	1,277.7	0.0	1,277.7	3,194.3	14,533	11,339	11,339	6,157
Rem	6,184.8	142.8	87.8	6,239.8	936.0	0.0	0.0	0.0	936.0	0.0	6,239.8	624.0	0.0	624.0	1,560.0	6,297	4,737	16,075	1,364
Total	18,961.9	891.9	836.9	19,016.9	2,852.5	0.0	0.0	0.0	2,852.5	0.0	19,016.9	1,901.7	0.0	1,901.7	4,754.2	20,830	16,075	16,075	7,521

Item 6.1.2 Gross and net oil and gas wells

	Oil		Gas		Non-producing		Total	
Country/Province	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada								
Alberta	1.0	0.5	0.0	0.0	5.0	2.4	6.0	2.9
Total	1.0	0.5	0.0	0.0	5.0	2.4	6.0	2.9

Item 6.2 Properties with no attributed reserves

Proved developed producing reserves have been assigned to the B1 - D0/15-22-039-26W4/0 oil well. The well was re-activated and came on production in January 2015. The well has produced sporadically since January averaging seven to ten days of production per month. Tanager plans on installing pumping equipment on the well in early 2016 to enhance performance. The production forecasts have taken into account this workover and reflects the increase of reserves in the total proved and proved plus probable cases.

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 2016. Proved reserves are assigned to these wells as the wells have demonstrated production over a number of years. The production forecasts are based on historical decline before the wells watered out and accounts for the fact that there will be lower drawdowns to minimize water coning.

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 2017. Proved reserves are assigned as this well has demonstrated production over a number of years. The well appeared to water out in 2008. Production decline is based on historical decline at this well before watering out and accounts for the fact that there will be lower drawdowns to minimize water coning. Higher production rates are expected since the whipstocked well is to be completed higher in the Leduc Formation.

Proved undeveloped and proved plus probable undeveloped reserves have been assigned to a location producing from the Leduc Formation with an on-stream date of August 2018. The reserves for the location C5 – LC/00-23-039-26W4/A, are based on the offset producing well, C1 – 02/05-23-039-26W4/0. The capital for the location is estimated by Deloitte.

Item 6.3 Forward contracts

There are no forwards contracts in place.

Item 6.4 Tax Horizon

The Company is expected to begin paying income tax in 2019 based on proved plus probable cash flow economics.

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, 2015:

	Property Acquisitions and Capital Expenditures
Nature of Cost	**Amount ($)**
Property Acquisition Costs	
Proved	110,000
Unproved	-
Exploration Costs	-
Development Costs	314,970
Total	424,970

Item 6.6 Exploration and development activities

During 2015, the 1D/0-15-22-39-36W4 well was recompleted and place on production as a flowing oil well.

Item 6.7 Production estimates

The following table discloses the total working interest volume for 2015 for each product type associated with the first year of the gross proved reserves and gross probable reserves reported in the Deloitte report effective December 31, 2015, based on forecast prices and costs:

Forecast production working interest January 1, 2016 - December 31, 2016		Proved	Proved + probable
Project B			
	Oil (Mbbl)	38.2	62.9
	Gas (MMcf)	150.1	245.7
	NGL (Mbbl)	6.2	10.2
Project C			
	Oil (Mbbl)	0	0
	Gas (MMcf)	0	0
	NGL (Mbbl)	0	0
Total			
	Oil (Mbbl)	38.2	62.9
	Gas (MMcf)	150.1	245.7
	NGL (Mbbl)	6.2	10.2

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:

	Total Company			
	Q1 2015	Q2 2015	Q3 2015	Q4 2015
Volumes				
light oil + NGLs, bopd	0	8	14	9
gas, Mcf/d	0	31	62	49
Boe/d	0	13	24	17
Light Oil and NGLs				
averages, $/bbl				
price	0.00	66.38	55.49	52.35
Gas				
averages, $/Mcf				
price	0	2.78	2.96	2.62
Royalties paid	0.00	4,226.58	5,923.59	3,665.54
Operating cost	0.00	26,250.37	38,397.44	33,919.30
Netback $/Boe)	0.00	-15.74	9.13	-1.56

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.

APPENDIX

FORM 51-101 F2 Report on Reserves Data by Independent Qualified Reserves Evaluator
FORM 51-101 F3 Report of Management and Directors on Reserves Data and Other Information

NI 51-101 Form F2
Report on reserves data
by
independent qualified reserves
evaluator or auditor

To the Board of Directors of Tanager Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year-end December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited $M	Evaluated $M	Reviewed $M	Total $M
Deloitte LLP	Tanager Energy Inc. Reserve estimation and economic evaluation December 31, 2015	Canada	-	$9,664.50	-	$9,664.50

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

Original signed by: "Robin G. Bertram"
Robin G. Bertram, P. Eng.
Partner

Execution date: February 5, 2016

TANAGER
ENERGY INC.

Form 51 – 101 F3
Report of Management and Directors
On Oil and Gas Disclosure

Report of Management and Directors on Reserves Data and Other Information

Management of Tanager Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.
The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator,

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

John E. Squarek, Director, President and CEO

Patrick Acham, Director

Hugh Loney, Director

David Pryce, Director

D Hyshka

Donna J. Hyshka, Chief Financial Officer

Corporate Head Office
3056 – 40th Ave. South
Lethbridge, Alberta, T1K 6Z
Phone: 403.388.0969
Webpage: www.tanagerenergy.com

TANAGER ENERGY INC.

Form 51 – 101 F3
Report of Management and Directors
On Oil and Gas Disclosure

Report of Management and Directors on Reserves Data and Other Information

Management of Tanager Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.
The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator,

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

John E. Squarek, Director, President and CEO

Patrick Acham, Director

Hugh Loney, Director

David Pryce, Director

Donna J. Hyshka, Chief Financial Officer

Corporate Head Office
3056 – 40th Ave. South
Lethbridge, Alberta, T1K 6Z
Phone: 403.388.0969
Webpage: www.tanagerenergy.com

TANAGER ENERGY INC.

Form 51 – 101 F3
Report of Management and Directors
On Oil and Gas Disclosure

Report of Management and Directors on Reserves Data and Other Information

Management of Tanager Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.
The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator,

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

John E. Squarek, Director, President and CEO

Patrick Acham, Director

Hugh Loney, Director

David Pryce, Director

Donna J. Hyshka, Chief Financial Officer

Corporate Head Office
3056 – 40th Ave. South
Lethbridge, Alberta, T1K 6Z
Phone: 403.388.0969
Webpage: www.tanagerenergy.com

TANAGER ENERGY INC.

Form 51 – 101 F3
Report of Management and Directors
On Oil and Gas Disclosure

Report of Management and Directors on Reserves Data and Other Information

Management of Tanager Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.
The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator,

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

John E. Squarek, Director, President and CEO

Patrick Acham, Director

Hugh Loney, Director

David Pryce, Director

Donna J. Hyshka, Chief Financial Officer

Corporate Head Office
3056 – 40th Ave. South
Lethbridge, Alberta, T1K 6Z
Phone: 403.388.0969
Webpage: www.tanagerenergy.com