Tenth Avenue Petroleum Corp.
Form 51-101F1
December 31, 2017

Tenth Avenue Petroleum Corp.
Form 51-101F1
Statement of Reserves and Other Oil and Gas Information

The reserves data presented in this form is based upon the "**RESERVES ASSESSMENT AND EVALUATION OF CANADIAN OIL AND GAS PROPERTIES**" by GLJ Petroleum Consultants, with an effective date of December 31, 2017. The reserves data summarizes oil, gas and liquid reserves of Tenth Avenue Petroleum Corp. and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data meets the requirements of National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

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

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

All of the Company's reserves are in Western Canada.

Abbreviations and Conversion

Terms used in NI 51-101 have the same meaning in this Form NI 51-101 F1.

Part 1 Date of Statement

1.1 Relevant Dates

1. Date of Statement: April 30, 2018
2. Effective Date of Statement: December 31, 2017
3. Preparation Date of Statement: April 30, 2018

Part 2 Disclosure of Reserves Data (Forecast Prices and Costs)

This section provides economic forecasts based on current costs and informed interpretation of posted reference prices (summarized in the following table) into the future: Historical price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Table 2.1.1
SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE
As of December 31, 2017
Forecast Prices and Costs
RESERVES SUMMARY

	Light And Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
Reserves Category	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mboe	Mboe
Proved										
Producing	2	2	0	0	2,796	2,374	49	31	517	428
Developed Nonproducing	3	3	0	0	862	818	12	8	1,580	147
Undeveloped	0	0	0	0	0	0	0	0	0	0
Total Proved	5	5	0	0	3,657	3,192	61	39	675	576
Total Probable	2	1	0	0	2,919	2,658	44	35	532	480
Total Proved Plus Probable	7	6	0	0	6,577	5,858	105	74	1,208	1,055

NET PRESENT VALUE SUMMARY

	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%		
Reserves Category	M$	M$	M$	M$	M$	$/boe	$/Mcfe
Proved							
Producing	3,316	2,717	2,264	1,928	1,675	5.29	0.88
Developed Nonproducing	602	534	460	396	344	3.12	0.52
Undeveloped	0	0	0	0	0	0.0	0.0
Total Proved	3,918	3,251	2,724	2,324	2019	4.73	0.79
Total Probable	3,052	1,725	967	533	280	2.01	0.34
Total Proved Plus Probable	6,970	4,976	3,690	2,857	2300	3.50	0.58

NET PRESENT VALUES OF FUTURE NET REVENUE

	After Income Taxes Discounted At (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	M$	M$	M$	M$	M$
Proved					
Producing	3,316	2,717	2,264	1,928	1,675
Developed Nonproducing	602	534	460	396	344
Undeveloped	0	0	0	0	0
Total Proved	3,918	3,251	2,724	2,324	2,019
Total Probable	3,052	1,725	967	533	280
Total Proved Plus Probable	6,970	4,976	3,690	2,857	2,300

Note: Unit values are based on Company Net Reserves.

Table 2.1.3
TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
As of December 31, 2017
Forecast Prices and Costs

Total Future Net Revenue (Undiscounted)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
Proved Producing	10,421	1,354	5,356	0	395	3,316	-	3,316
Proved Developed Nonproducing	3,241	186	2,145	0	308	602	-	602
Proved Undeveloped	0	0	0	0	0	0	-	-
Total Proved	13,662	1,540	7,501	0	703	3,918	-	3,918
Total Probable	12,749	904	6,655	1,926	212	3,052	-	3,052
Total Proved Plus Probable	26,412	2,444	14,156	1,926	916	6,970	-	6,970

NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP
As of December 31, 2017
Forecast Prices and Costs

Future Net Revenue Before Income Taxes [2]
(Discounted at 10% per year)

Entity Name	**Percent Value Discount M$**	**$/boe**	**$/Mcfe**
Proved Producing			
Light & Medium Oil [1]	68	27.82	4.64
Conventional Natural Gas [2]	2,196	5.16	0.86
Total: Proved Producing	2,264	5.29	0.88
Total Proved			
Light & Medium Oil [1]	68	27.82	4.64
Conventional Natural Gas [2]	2,656	4.63	0.77
Total: Total Proved	2,724	4.73	0.79
Total Proved Plus Probable			
Light & Medium Oil [1]	86	25.82	4.30
Conventional Natural Gas [2]	3,604	3.43	0.57
Total: Total Proved Plus Probable	3,690	3.50	0.58

Notes:

1 Including solution gas and other by-products
2 Including by by-products but excluding solution gas
3 Other Company revenue and costs not related to a specific production group have been allocated proportionally to production groups. Unit values are based on Company Net Reserves

Part 3 PRICING ASSUMPTIONS

Item 3.2.1(a) Forecast Prices Used in Estimates

The pricing assumptions used in the GLJ Report to determine net values of future net revenue (forecast) and the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101. Effective January 1, 2018.

Table 1

GLJ Petroleum Consultants

Crude Oil and Natural Gas Liquids

Price Forecast

Effective January 1, 2018

Year	Inflation %	CADUSD Exchange Rate USD/CAD	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Constant 2018 $ USD/bbl	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Then Current USD/bbl	Brent Blend Crude Oil FOB North Sea Then Current USD/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current CAD/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	WCS Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current CAD/bbl	Light Sour Crude Oil (35 API, 1.2%S) at Cromer Then Current CAD/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane CAD/bbl	Edmonton Propane CAD/bbl	Edmonton Butane CAD/bbl	Edmonton C5+ Stream Quality CAD/bbl
2008	2.4	0.9428	116.72	99.64	98.30	102.90	84.31	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.8798	70.67	61.78	62.50	66.32	60.18	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.9711	90.64	79.52	80.25	77.87	68.45	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.0115	106.54	95.12	110.86	95.53	78.59	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012	1.5	1.0009	102.53	94.21	111.71	86.60	74.42	73.13	63.64	84.51	81.37	N/A	29.04	66.70	100.84
2013	0.9	0.9711	105.01	97.96	108.77	93.47	76.33	75.01	65.11	92.30	88.13	N/A	38.88	68.81	104.70
2014	1.9	0.9055	98.74	93.00	99.71	94.58	81.08	81.03	73.73	92.68	89.67	N/A	45.53	69.20	102.44
2015	1.1	0.7831	50.82	48.78	53.60	57.20	45.50	44.82	39.25	55.49	51.87	N/A	6.49	36.75	60.42
2016	1.4	0.7551	44.68	43.38	45.05	53.08	39.83	38.96	32.78	51.46	48.84	N/A	13.40	34.49	56.25
2017	1.6	0.7711	51.69	50.88	54.16	62.78	50.85	50.46	44.56	62.02	59.90	N/A	28.64	44.58	66.80
2018 Q1	2.0	0.790	59.00	59.00	66.00	70.25	45.44	44.94	34.25	68.85	65.34	5.91	42.15	54.80	77.22
2018 Q2	2.0	0.790	59.00	59.00	66.00	70.25	49.87	49.37	40.01	68.85	65.34	6.51	42.15	54.80	77.22
2018 Q3	2.0	0.790	59.00	59.00	65.00	70.25	51.13	50.63	42.13	68.85	65.34	7.09	38.64	52.69	75.63
2018 Q4	2.0	0.790	59.00	59.00	65.00	70.25	51.13	50.63	42.13	68.85	65.34	7.49	38.64	52.69	75.63
2018 Full Year	2.0	0.790	59.00	59.00	65.50	70.25	49.39	48.89	39.63	68.85	65.34	6.75	40.40	53.74	76.42
2019	2.0	0.790	57.84	59.00	63.50	70.25	53.66	53.16	45.71	68.85	65.34	7.95	36.53	49.18	74.68
2020	2.0	0.800	57.67	60.00	63.00	70.31	56.75	56.25	49.81	68.91	65.39	9.12	35.93	49.22	74.38
2021	2.0	0.810	59.37	63.00	66.00	72.84	59.76	59.26	52.89	71.38	67.74	10.34	36.06	50.99	77.16
2022	2.0	0.820	60.97	66.00	69.00	75.61	62.70	62.20	55.89	74.10	70.32	11.14	36.29	52.93	79.88
2023	2.0	0.830	62.50	69.00	72.00	78.31	65.56	65.06	58.82	76.75	72.83	11.51	37.59	54.82	82.53
2024	2.0	0.830	63.93	72.00	75.00	81.93	69.17	68.67	62.43	80.29	76.19	11.76	39.33	57.35	86.14
2025	2.0	0.830	65.29	75.00	78.00	85.54	72.79	72.29	66.05	83.83	79.55	12.02	41.06	59.88	89.76
2026	2.0	0.830	66.00	77.33	80.33	88.35	75.60	75.10	68.86	86.58	82.16	12.27	42.41	61.84	92.57
2027	2.0	0.830	66.00	78.88	81.88	90.22	77.46	76.96	70.72	88.41	83.90	12.53	43.30	63.15	94.43
2028+	2.0	0.830	66.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

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Table 2
GLJ Petroleum Consultants
Natural Gas and Sulphur
Price Forecast
Effective January 1, 2018

Year	NYMEX Henry Hub Near Month Contract Constant 2018 $ USD/MMBtu	NYMEX Henry Hub Near Month Contract Then Current USD/MMBtu	Midwest Price at Chicago Then Current USD/MMBtu	AECO/NIT Spot Then Current CAD/MMBtu	Alliance Transfer Pool Spot Then Current CAD/MMBtu	Alberta Plant Gate Spot Constant 2018 $ CAD/MMBtu	Alberta Plant Gate Spot Then Current CAD/MMBtu	Alberta Plant Gate ARP CAD/MMBtu	Saskatchewan Plant Gate SaskEnergy CAD/MMBtu	Saskatchewan Plant Gate Spot CAD/MMBtu	Sumas Spot USD/MMBtu	British Columbia Westcoast Station 2 CAD/MMBtu	British Columbia Spot Plant Gate CAD/MMBtu	Sulphur FOB Vancouver USD/lt
2008	10.42	8.90	8.91	8.16	N/A	9.29	7.94	7.88	8.07	8.04	6.47	8.21	7.99	497.39
2009	4.77	4.16	4.05	3.99	N/A	4.34	3.79	3.85	3.87	3.83	3.80	3.90	3.70	57.06
2010	5.01	4.40	4.53	4.01	N/A	4.31	3.78	3.77	3.96	3.85	4.12	3.78	3.63	88.94
2011	4.51	4.03	4.21	3.62	N/A	3.83	3.42	3.46	3.57	3.58	3.90	3.33	3.18	217.16
2012	3.07	2.83	2.92	2.40	N/A	2.41	2.21	2.25	2.31	2.26	2.70	2.30	2.12	201.03
2013	3.99	3.73	3.81	3.18	N/A	3.17	2.96	2.98	3.09	3.10	3.71	3.14	2.94	105.74
2014	4.54	4.28	5.36	4.50	N/A	4.52	4.26	4.22	4.39	4.42	4.37	4.29	4.07	145.41
2015	2.74	2.63	2.85	2.70	N/A	2.57	2.47	2.56	2.71	2.61	2.31	1.80	1.59	139.61
2016	2.63	2.55	2.48	2.18	2.36	2.00	1.94	1.93	2.18	2.09	2.18	1.77	1.60	82.96
2017	3.07	3.02	3.04	2.16	2.12	1.93	1.90	2.09	2.26	2.29	2.60	1.55	1.32	85.75
2018 Q1	2.80	2.80	2.70	1.95	1.95	1.70	1.70	1.70	1.80	1.85	2.55	1.10	0.89	90.00
2018 Q2	2.80	2.80	2.70	2.13	2.13	1.87	1.87	1.87	1.97	2.03	2.20	1.28	1.07	90.00
2018 Q3	2.90	2.90	2.80	2.29	2.29	2.04	2.04	2.04	2.14	2.19	2.50	1.49	1.29	90.00
2018 Q4	2.90	2.90	2.80	2.41	2.41	2.15	2.15	2.15	2.25	2.31	2.65	1.71	1.50	90.00
2018 Full Year	2.85	2.85	2.75	2.20	2.20	1.94	1.94	1.94	2.04	2.10	2.48	1.40	1.19	90.00
2019	2.94	3.00	2.90	2.54	2.54	2.24	2.28	2.28	2.38	2.44	2.50	1.99	1.78	100.00
2020	3.12	3.25	3.15	2.88	2.88	2.52	2.62	2.62	2.72	2.78	2.75	2.48	2.27	102.00
2021	3.30	3.50	3.40	3.24	3.24	2.80	2.97	2.97	3.07	3.14	3.00	2.94	2.73	104.04
2022	3.42	3.70	3.60	3.47	3.47	2.96	3.20	3.20	3.30	3.37	3.20	3.17	2.96	106.12
2023	3.50	3.86	3.76	3.58	3.58	3.00	3.31	3.31	3.41	3.48	3.36	3.28	3.06	108.24
2024	3.50	3.94	3.84	3.66	3.66	3.00	3.38	3.38	3.48	3.56	3.44	3.36	3.14	110.40
2025	3.50	4.02	3.92	3.73	3.73	3.01	3.45	3.45	3.55	3.63	3.52	3.43	3.21	112.62
2026	3.50	4.10	4.00	3.80	3.80	3.01	3.53	3.53	3.63	3.70	3.60	3.50	3.29	114.87
2027	3.50	4.18	4.08	3.88	3.88	3.01	3.60	3.60	3.70	3.78	3.68	3.58	3.36	117.17
2028+	3.50	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.01	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

less otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
e plant gate price represents the price before raw gathering and processing charges are deducted.

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Item 3.2.1(a) Issuers weighted Average Historical Prices for the most recent Financial Year

The Company's weighted average prices for the year ended December 31, 2017 were as follows:

Oil (light crude)	$53.70/bbl
Natural Gas	$1.48/mcf
Liquids	$34.65/bbl

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of the Corporation's gross reserves based on forecast prices and costs.

TABLE FP-5A

DECEMBER 31, 2017
RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2016	2	1	3	2	1	3				24	8	32
Discoveries												
Extensions*												
Infill Drilling*												
Improved Recovery*												
Technical Revisions												
Acquisitions	3	1	4	3	1	4				37	36	73
Dispositions												
Economic Factors												
Production												
December 31, 2017	5	2	7	5	2	7				61	44	105

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2016	133	44	180	133	45	180				48	17	65
Discoveries												
Extensions*												
Infill Drilling*												
Improved Recovery*												
Technical Revisions												
Acquisitions	3,524	2,874	6,398	3,524	2,874	6,398				627	516	1,143
Dispositions												
Economic Factors												
Production												
December 31, 2017	3,657	2,919	6,577	3,657	2,919	6,577				675	532	1,208

* *The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions , under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".*

TABLE FP-5B
DECEMBER 31, 2016
RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2015	2	1	2	2	1	0	0	0	0	24	8	32
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	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
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	1	0	1	1	0	0	0	0	0	-0	-1	2
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	-0	-1	-1
Production	-0	0	-0	-0	0	-0	0	0	0	-0	0	-6
December 31, 2016	2	1	3	2	1	2	0	0	0	21	7	28

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2015	133	47	180	133	47	180				48	17	65
Discoveries												
Extensions*												
Infill Drilling*												
Improved Recovery*												
Technical Revisions	16	-2	13	16	-2	13				3	-1	2
Acquisitions												
Dispositions												
Economic Factors										-0	-1	-1
Production	-18		-18	-18		-18				-6		-6
December 31, 2016	130	44	174	130	44	174				45	15	60

* *The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".*

Part 5 Additional Information Relating to Reserves Data

5.1 Undeveloped Reserves Attributed at Current Year

Proved Undeveloped Reserves

L&M Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		BOE (Mbbl)	
Attributed This Year*	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
0	0	0	0	0	0	0	0	0	0

Probable Undeveloped Reserves

L&M Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		BOE (Mbbl)	
Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
0	0	0	0	0	1,594	0	22	0	287

* Refers to reserves first attributed in this fiscal year ending on the effective date.

BOE Factors:							
HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

5.2 Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments 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. Tenth Avenue Petroleum Corp's reserves are evaluated by GLJ Petroleum Consultants which is an independent engineering firm. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Tenth Avenue Petroleum Corp's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company and have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com). Please refer to these documents for a discussion of these matters.

5.3 Future Development Costs

Company Annual Capital Expenditures (M$'s)
Forecast Prices and Costs

Totals

Entity Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Subtotal	Remainder	Total	10% Discounted
Proved Producing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved Plus Probable	0	0	0	1,926	0	0	0	0	0	0	0	0	1,926	0	1,926	1,380

(a) Tenth Avenue Petroleum Corp expects that it will be able to fund the estimated future development costs from a combination of internally generated cash flow, bank debt and equity financings. The Company anticipates that the cost of future financings will be market driven.

(b) Tenth Avenue Petroleum Corp expects that the costs of funding will not significantly affect disclosed reserves or future net revenue.

Part 6 Other Oil and Gas Information

6.1 Oil & Gas Properties and Wells (as of December 31, 2017)

1. All of the Company's properties are located onshore in Western Canada.

   There are no statutory or other mandatory relinquishments, surrenders, back-ins or change in ownership obligations against these reserves.

2. All wells are in Alberta, Saskatchewan, British Columbia, Canada

Oil and Gas Properties and Wells

		Oil Wells		Gas Wells		Other	
		Gross	Net	Gross	Net	Gross	Net
Alberta	Producing	1	7%	1	35%		
	Non-producing	3	3				
	Total Alberta	0	0				
Saskatchewan	Producing	1	ORR				
British Columbia (1)	Total	0	0				

(1) Water Disposal well

6.2 Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2017.

Unproved properties (acres)

	Gross	Net	Commitments
Waskahigan			Nil

6.3 Forward Contracts

The Company has no Forward Contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs (Cdn wells only)

Year

Entity Description	2018	2019	2020	2021	2022	2023	2024	2025	Subtotal	Remainder	Total	10% Discounted
Proved Producing	0	6	0	0	0	1	0	0	7	0	7	
Total Proved	0	6	0	0	0	1	0	0	7	0	7	
Total Proved Plus Probable	0	6	0	0	0	1	0	0	7	0	7	

(a) The Company estimates abandonment and reclamation costs on a well by well basis.

(b) The Company operates 11 wells which have been abandoned and substantially remediated and expects future costs to be under $5,000 per well to obtain remediation certificates.

(c) The Company is a non operator in 3 wells with average interest of 18% and does not expect the operators to incur abandonment and reclamation costs in next 3 years.

(d) The Company is the operator of 3 net Canadian wells and 1 Texas wells which it expects to abandon in next 3 years.

(e) The Company has estimated its Cdn well abandonment and reclamation costs to be $1,000,000. The sum of $200,000 is set aside in deposits.

(f) There are no amounts for abandonment costs for wells not deducted from future revenue.

6.5 Tax Horizon

As the Company does not yet have any significant production, it is not required to pay income taxes for the year ending December 31, 2017. Further, the Company does not expect to be taxable in the immediately foreseeable future.

At December 31, 2017, the Company has $16.4MM of available non-capital loss carry forwards in the US and Canada to reduce taxable income for income tax purposes expiring between 2026 and 2033.

The Company has the following tax pool balances: CDE $80,778; COGPE $122,,061 (Dec 31-16)

6.6.1.1 Costs Incurred in 2017

Costs Incurred

Property acquisition-proved properties	$ 1,400,000
Property acquisition-unproved properties	$ Nil
Exploration (does not include Texas wells)	$ Nil
Development (lease and well equipment)(does not include Texas wells)	$ Nil

6.7 Exploration and Development Activities

1 Viking oil well was drilled and completed in 2012/2013. The El Indio #1H well was drilled in Texas in 2011.

6.8 Production Estimates

The volume of Cdn production estimated for 2018 reflected in the estimates of future and net revenue disclosed under Part 2 is:

SUMMARY OF FIRST YEAR PRODUCTION AND OIL AND GAS RESERVES

	S/B 2017 Average Daily Production										Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
Entity Description	bbl/d	bbl/d	bbl/d	bbl/d	Mcf/d	Mcf/d	bbl/d	bbl/d	bbl/d	bbl/d	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mboe	Mboe
Proved Producing																				
Other Properties	2	1			35	29	4	2	11	8										
Waskahigan Minor	0	0			1,310	1,065	18	11	236	189										
Total: Proved Producing	2	1	0	0	1,345	1,093	22	13	248	197	2	2	0	0	2,796	2,374	49	31	517	428
Proved Developed Nonproducing																				
Other Properties	0				0	0	0	0	0	0										
Waskahigan Minor	1				141	134	2	1	26	24										
Total Proved Developed Nonproducing	1	0	0	0	141	134	2	1	26	24	3	3	0	0	862	818	12	8	1,500	147
Proved Undeveloped																				
Other Properties	0	0	0	0	0	0	0	0	0	0										
Waskahigan Minor	0	0	0	0	0	0	0	0	0	0										
Total: Proved Undeveloped	0	0	0	0	0	0	0	0	0											
Total Proved																				
Other Properties	2	1			35	29	4	2	11	8										
Waskahigan Minor	1	1			1,451	1,199	20	12	263	213										
Total: Total Proved	3	2	0	0	1,486	1,227	24	14	274	221	5	5	0	0	3,657	3,192	61	39	675	576
Total Probable																				
Other Properties					1	1														
Waskahigan Minor					23	19														
Total: Total Probable					242	19					2	1	0	0	2,919	2,650	44	35	532	480
Total Proved Plus Probable																				
Other Properties					36	29	4	2	12	8										
Waskahigan Minor					1,474	1,217	20	13	267	216										
Total: Total Proved Plus Probable	3	2	0	0	1,510	1,246	24	15	278	224	7	6	0	0	6,577	5,858	105	74	1,208	1,055

BOE Factors:	HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
	COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

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6.9 Production History

The following table summarizes the Corporation's average daily Cdn production volumes during the year ended December 31, 2017 by production type.

Table 6.9.1
Production History – Year ended December 31, 2017

	Oil		Gas		Other – NGL, Propane, Butane and Pentane	
	(Bbls/day)	Aggregate Bbl	(mcf/day)	Aggregate mcf	(Bbls/day)	Aggregate Bbls
Canadian	4.25	1,552	398	143,280	9.36	

Although the purchase of the Waskahigan property was effective May 1, 2017, the production from May 1 to July 31, 2017 was treated as an adjustment to the purchase prices and is not included in the above chart. Also the company shut in its production for all wells for the period from September 2017 to December 31, 2017 with the exception of 1 well which was restarted in mid-November.