STORM RESOURCES

2017 YEAR-END REPORT

ANNUAL MEETING

The Annual General and Special Meeting of shareholders will be held at 3:30 p.m. on Wednesday, May 16, 2018 at Calgary TELUS Convention Centre, Rooms TELUS 108/109 North Building, 136 Eighth Avenue S.E., Calgary, Alberta, Canada.

All shareholders and invited guests are encouraged to attend.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Dec. 31, 2017	Three Months to Dec.31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
FINANCIAL				
Revenue from product sales[1]	34,844	26,244	123,306	77,283
Funds flow	21,323	11,985	64,080	34,380
Per share – basic and diluted ($)	0.18	0.10	0.53	0.29
Net income (loss)	8,624	(12,898)	39,689	(38,460)
Per share – basic and diluted ($)	0.07	(0.11)	0.33	(0.32)
Operations capital expenditures[2]	26,126	33,399	81,685	65,538
Land and property acquisitions/(dispositions)	-	-	-	(600)
Debt including working capital deficiency[2][3]	106,124	89,841	106,124	89,841
Common shares (000s)				
Weighted average - basic	121,557	120,488	121,531	120,053
Weighted average - diluted	121,557	120,488	121,616	120,053
Outstanding end of period – basic	121,557	120,764	121,557	120,764
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales[1]	21.12	21.42	21.09	15.97
Royalties	(0.63)	(0.99)	(1.19)	(0.79)
Production	(5.68)	(6.95)	(6.04)	(6.78)
Transportation	(0.69)	(0.55)	(0.76)	(0.45)
Field operating netback[2]	14.12	12.93	13.10	7.95
Realized (loss) gain on hedging	0.41	(1.45)	(0.40)	0.93
General and administrative	(0.94)	(0.95)	(1.05)	(1.10)
Interest and finance costs	(0.67)	(0.74)	(0.69)	(0.68)
Funds flow per Boe	12.92	9.79	10.96	7.10
Barrels of oil equivalent per day (6:1)	17,936	13,320	16,017	13,219
Natural gas production				
Thousand cubic feet per day	87,375	66,173	78,521	65,478
Price (Cdn$ per Mcf)[1]	2.26	2.86	2.58	2.05
Condensate production				
Barrels per day	1,914	1,381	1,685	1,303
Price (Cdn$ per barrel)[1]	69.53	57.17	61.80	49.34
NGL production				
Barrels per day	1,460	910	1,245	1,003
Price (Cdn$ per barrel)[1]	33.29	18.64	25.15	12.51
Wells drilled (100% working interest)	7.0	5.0	16.0	12.0
Wells completed (100% working interest)	3.0	5.0	12.0	10.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements including field operating netback, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 39 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2017 FOURTH QUARTER HIGHLIGHTS

- Production increased by 34% on a per-share basis from the prior year to a record high of 17,936 Boe per day which was consistent with the low end of guidance (18,000 to 19,000 Boe per day).

- Liquids production (condensate plus NGL) increased 47% from the prior year to 3,374 barrels per day and exceeded the 32% increase in natural gas production as drilling has shifted to areas at Umbach where higher condensate-gas ratios are being realized. Liquids represented 48% of production revenue versus 34% last year.

- At the end of the quarter, there was an inventory of 12 Montney horizontal wells (12.0 net) at Umbach that had not started producing which includes two completed wells. Five horizontal wells (5.0 net) started production in the quarter.

- Montney horizontal well performance at Umbach continues to improve as length is increased. The three wells (3.0 net) from 2017 with the most history have an average length of 1,650 metres and averaged 4.0 Mmcf per day gross raw gas during their eleventh month which is approximately 50% better than the average well completed in 2014 to 2016. Wells drilled in the fourth quarter averaged 2,090 metres which is expected to result in further improvements.

- Revenue per Boe declined by 1% year over year with higher liquids production and pricing offsetting a 21% decrease in the natural gas price.

- Natural gas sales continue to be maximized into the higher priced Chicago market with 70% of fourth quarter sales being at Chicago.

- Controllable cash costs (production, general and administrative, interest and finance) decreased 16% year over year to $7.29 per Boe. This was mainly due to production costs declining 18% as a result of continuing production growth and a new processing arrangement.

- Funds flow was $21.3 million ($12.92 per Boe) which was the highest quarterly funds flow achieved since inception and represents a per-share increase of 83% from a year ago. The improvement was largely the result of a 35% increase in production volumes and a 32% increase in the funds flow netback.

- Net income was $8.6 million or $0.07 per share and a significant improvement from the net loss of $12.9 million in the prior year as net revenue increased more than expenses. Net revenue including hedging increased with production growth and with a $13.1 million reduction in the unrealized hedging loss.

- Capital investment was $26.1 million with 82% being invested in drilling seven horizontal wells (7.0 net) and completing three horizontal wells (3.0 net). This was consistent with guidance at $26.0 million.

- Total debt including working capital deficiency was $106.1 million which is 1.2 times annualized fourth quarter funds flow. The bank credit facility is $165.0 million.

- Commodity price hedges continue to be added and currently protect approximately 40% of forecast production for 2018 using the low end of guidance (20,000 Boe per day).

2017 YEAR-END HIGHLIGHTS

- Production was 16,017 Boe per day (18% condensate and NGL), a year-over-year increase of 20% on a per-share basis and consistent with guidance (16,200 Boe per day).
- Liquids production (condensate plus NGL) was 2,930 barrels per day, an increase of 27% from last year and higher than the 20% increase in natural gas production.
- The corporate decline rate was approximately 32% in 2017 (December 2016 corporate production was 14,666 Boe per day with the same wells producing 9,900 Boe per day in December 2017). The 13 horizontal wells that were turned on in 2017 produced 9,300 Boe per day in December 2017.
- The 12 horizontal wells completed in 2017 had an average length of 1,750 metres which is 38% longer than wells completed in 2014 to 2016. The last seven wells that were drilled in 2017 averaged 2,090 metres (these wells will be completed in 2018). Rates and reserves are expected to increase in proportion to the added length.
- Controllable cash costs (production, general and administrative, interest and finance) averaged $7.78 per Boe for the year, a decrease of $0.78 per Boe, or 9%, from the previous year.
- Funds flow was $64.1 million ($0.53 per share), a year-over-year increase of 83% on a per-share basis with the improvement coming from production growth combined with a 54% increase in the funds flow netback. The higher funds flow netback was mainly from higher commodity prices and a reduction in per-Boe controllable cash costs.
- Net income improved to $39.7 million ($0.33 per share) from a net loss of $38.5 million in the prior year. This was primarily due to an unrealized hedging gain which was a $54.8 million improvement from last year plus increased production and higher realized commodity prices.

YEAR-END RESERVE EVALUATION HIGHLIGHTS

- The all-in in Finding, Development & Acquisition ("FD&A") cost showed significant year-over-year improvement. Proved developed producing ("PDP") FD&A was $5.76 per Boe, a 16% improvement. Total proved ("1P") FD&A was $3.06 per Boe, a 38% improvement. Total proved plus probable ("2P") FD&A was $1.27 per Boe, a 77% improvement.
- Recycle ratio using the funds flow netback divided by FD&A was 1.9 for PDP, 3.6 for 1P, and 8.6 for 2P. Excluding hedging, the PDP recycle ratio improves to 2.0.
- By commodity and on a 2P basis, liquids reserves increased 36% while natural gas reserves increased 21%.
- Reserve life index ("RLI") using fourth quarter production is 5.2 years for PDP, 14.9 years for 1P, and 19.7 years for 2P.
- Reserve additions for PDP were the highest since Storm's inception and replaced 143% of annual production (351% for 1P and 424% for 2P).
- Reserve quality continued to improve with PDP increasing to 26% of 2P from 24% last year.
- On a per-share basis, the year-over-year increase in reserves was 32% for PDP, 26% for 1P, and 23% for 2P.
- 2P reserves are recognized in the Montney at Umbach on 33.5 net sections which is only 22% of the total land position.

- Technical revisions added 13% to PDP, 14% to 1P, and 13% to 2P as a result of actual well performance exceeding the PDP forecast and with longer horizontal wells used for 1P and 2P future drilling locations.

- Actual results achieved by Storm in 2017 were significantly better than what was predicted in last year's evaluation. The actual average drill and complete cost in 2017 was $4.2 million which was less than the estimated cost of $4.5 million in last year's evaluation even though longer horizontal wells were drilled. Estimated 2P reserves assigned to wells drilled and completed in 2017 averaged 6.6 Bcf gross raw gas which was materially higher than the 4.6 Bcf estimate for future 2P drilling locations in last year's evaluation.

Reserves (Mboe)	**Increase From Last Year**	**2017**	**2016**	**2015**
PDP	+33%	33,729	25,395	20,810
1P	+27%	97,617	77,097	73,434
2P	+24%	128,963	104,192	100,722
PDP as % of 2P		26%	24%	21%
1P as a % of 2P		76%	74%	73%

Reserves Per Share Outstanding (Mboe per million shares)	**Increase From Last Year**	**2017**	**2016**	**2015**
PDP	+32%	277	210	174
1P	+26%	803	638	615
2P	+23%	1,061	862	844

All-in FD&A Cost Including Change in FDC ($/Boe)	**2017**	**2016**	**2015**	**3 Year Total**
PDP	$5.76	$6.89	$6.53	$6.31
1P	$3.06	$4.97	$3.38	$3.48
2P	$1.27	$5.48	$0.50	$1.68

Recycle Ratio Using All-in FD&A Cost	**2017**	**2016**	**2015**	**3 Year Total**
Funds Flow netback ($/Boe)	$10.96	$7.10	$10.76	$9.60
PDP Recycle	1.9	1.0	1.6	1.5
1P Recycle	3.6	1.4	3.2	2.8
2P Recycle	8.6	1.3	21.5	5.7

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 109,000 net acres (155 net sections). To date, Storm has drilled 69 horizontal wells (65.4 net).

Liquids recovery during the fourth quarter was 39 barrels per Mmcf sales (57% being higher priced condensate), an increase from 36 barrels per Mmcf sales last year.

Activity in the fourth quarter included completing three horizontal wells (3.0 net) and drilling seven horizontal wells (7.0 net). Notably, the horizontal drills had an average length of 2,090 metres, an increase of 57% from the average length of the wells drilled in 2014 to 2016. Five horizontal wells (5.0 net) started production which left an inventory of 12 horizontal wells (12.0 net) that had not started producing at the end of the quarter including two completed wells.

During 2017, 13 horizontal wells (13.0 net) started producing with these wells adding 7,730 Boe per day in the fourth quarter.

With drilling focused in the south and to the northwest, the condensate-gas ratio on the 2017 wells is approximately 30% higher than on the 2014 to 2016 wells. This has resulted in corporate liquids production increasing at a higher rate than natural gas production.

Since 2013, approximately $100.0 million has been invested in building out infrastructure (pipelines and facilities) with current capacity totaling 115 Mmcf per day raw gas from three field compression facilities. Throughput in the fourth quarter was 93 Mmcf per day raw gas (December averaged 100 Mmcf per day). Capacity can be increased to 150 Mmcf per day by installing additional compression which was purchased and moved to site in the first quarter of 2018 at a cost of $5.0 million (requires additional $2.0 million for installation). The increased compression capacity would support growth in corporate production to approximately 27,000 Boe per day.

Storm's produced raw natural gas is sour (approximately 1.2% H_2S) with 81% directed to the McMahon Gas Plant in the fourth quarter and 19% directed to the Stoddart Gas Plant. Firm processing commitments total 65 Mmcf raw gas per day with terms of 5 to 15 years at McMahon and 15 Mmcf per day until April 2018 at Stoddart.

A summary of horizontal wells is provided below. The wells completed in 2017 are 38% longer than 2014 to 2016 wells while the drilling and completion cost per meter decreased by 16% from 2016. Results to date from the 2017 wells are very encouraging even though this is not apparent from IP90 and IP180 rates as the majority of wells are initially rate restricted to manage fluid rates. More information on well performance is available in the presentation on Storm's website.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP90 Cal Day Mmcf/d Raw	IP180 Cal Day Mmcf/d Raw	IP365 Cal Day Mmcf/d Raw
2014 12 hz's(1)	19	1,170 m	$4.6 million $3,950 per meter	4.9 Mmcf/d 12 hz's	4.4 Mmcf/d 12 hz's	3.5 Mmcf/d 12 hz's
2015 11 hz's	22	1,360 m	$4.5 million $3,300 per meter	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 11 hz's
2016 10 hz's	25	1,300 m	$3.7 million $2,850 per meter	5.1 Mmcf/d 10 hz's	4.2 Mmcf/d 10 hz's	3.5 Mmcf/d 7 hz's
2017 12 hz's	34	1,750 m	$4.2 million $2,400 per meter	4.9 Mmcf/d 8 hz's	4.4 Mmcf/d 5 hz's	4.4 Mmcf/d 2 hz's
2018 3 hz's	37	2,090 m	$5.3 million $2,550 per meter			

(1) 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth by continually layering in hedges to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that approximately 80% of Storm's liquids production is priced in reference to WTI. The current hedge position is summarized below and protects approximately 40% of forecast production for 2018 using the low end of guidance (20,000 Boe per day).

2018		
Crude Oil	1,362 Bpd	WTI Cdn$64.43/Bbl floor, Cdn$68.08/Bbl ceiling
Propane	300 Bpd	Conway Cdn$39.55/Bbl
Natural Gas	750 GJ/d (600 Mcf/d)	AECO Cdn$2.80/GJ
	34,200 Mmbtu/d (29,000 Mcf/d)	Chicago Cdn$3.81/Mmbtu(1)
	2,200 Mmbtu/d (1,850 Mcf/d)	Chicago US$2.70/Mmbtu(1)
	9,000 Mmbtu/d (7,600 Mcf/d)	Sumas Cdn$3.02/Mmbtu
	3,000 GJ/d (2,400 Mcf/d)	Station 2 - AECO basis -$0.345/GJ
2019		
Crude Oil	325 Bpd	WTI Cdn$67.28/Bbl floor, Cdn$71.14/Bbl ceiling
Natural Gas	4,000 Mmbtu/d (3,400 Mcf/d)	Chicago Cdn$3.50/Mmbtu(1)
	1,500 Mmbtu/d (1,275 Mcf/d)	Chicago US$2.65/Mmbtu(1)

(1) The Alliance Pipeline tariff to Chicago is approximately Cdn$1.20 per Mmbtu including the cost of fuel.

Total firm transportation capacity is currently 77 Mmcf per day and increases to 102 Mmcf per day in April 2018. Capacity on the Alliance Pipeline to Chicago increased by five Mmcf per day in December 2017 and currently totals 55 Mmcf per day. Natural gas production exceeding firm capacity is directed to Chicago and/or Station 2 using interruptible pipeline capacity (depending on which sales point offers a higher price). Using forecast production for 2018, firm transportation capacity will result in approximately 54% to 68% of natural gas sales at Chicago pricing, 11% at Sumas pricing less a marketing adjustment, 5% at ATP pricing, 3% to 17% at Station 2 pricing and 13% at AECO pricing. Note that natural gas marketing arrangements result in the cost of transportation on the Alliance Pipeline for sales in Chicago being deducted from revenue ($8.3 million deducted in the fourth quarter of 2017). Additional information is provided in the presentation on Storm's website.

OUTLOOK

In the fourth quarter of 2017, actual production of 17,936 Boe per day was at the low end of guidance of 18,000 to 19,000 Boe per day. This was the result of the low Station 2 natural gas price in the quarter ($0.53/GJ) which resulted in the start-up of new wells being deferred until December when Alliance capacity was increased by an additional five Mmcf per day. During October and November, production was maintained at a level that fulfilled firm transportation commitments.

For the first quarter of 2018, production is forecast to be 19,500 to 20,500 Boe per day which represents year-over-year growth of 18% at the mid-point. Production to date in the first quarter has averaged 19,700 Boe per day based on field estimates. Capital investment is expected to be $23.0 million which includes completing three horizontal wells on the Nig land block at Umbach plus constructing a 13-kilometer gathering pipeline to the Nig land block.

In the first half of 2018, capital investment is expected to be less than funds flow using forecast commodity prices which is expected to result in debt being reduced by approximately $10.0 million to $15.0 million.

Updated guidance for 2018 is provided in the table below and is largely unchanged except for updating forecast commodity prices to reflect pricing to date and approximately the current forward strip for the remainder of the year. A range has been provided for capital investment and for forecast production with both mainly contingent on the natural gas price at Station 2 which is where Storm's incremental natural gas growth would be sold. The low end of forecast production for the year represents year-over-year growth of 25% with capital investment expected to be less than estimated funds flow. The production forecast uses a 7.5 Bcf type curve for future horizontal wells at Umbach (previously a 6.3 Bcf type curve was used which was based on the performance of shorter horizontal wells completed in 2014 to 2016).

2018 Guidance	Previous November 14, 2017	Current March 1, 2018
$Cdn/$US exchange rate	0.79	0.80
Chicago daily natural gas - US$/Mmbtu	$2.80	$2.60
Sumas monthly natural gas - US$/Mmbtu	$2.40	$1.90
AECO daily natural gas - Cdn$/GJ	$1.80 - $2.10	$1.40
Station 2 daily natural gas - Cdn$/GJ	$1.30 - $1.70	$1.05
WTI - US$/bbl	$52.00	$56.00
Edmonton light oil - Cdn$/Bbl	$62.00	$64.00
Est revenue net of transport (excl hedges) - $/Boe	$18.00 - $19.25	$17.00 - $18.50
Est operating costs - $/Boe	$5.75	$5.75
Est royalty rate (% revenue before hedging)	6% - 9%	6% - 8%
Est operations capital investment (excl A&D) - $ million	$55.0 - $90.0	$55.0 - $90.0
Est cash G&A - $ million - $/Boe	$6.0 - $7.0 $0.70 - $0.95	$6.0 - $7.0 $0.70 - $0.95
Est interest expense - $ million	$4.5 - $5.5	$4.5 - $5.5
Forecast fourth quarter production - Boe/d % liquids	20,000 - 27,000 17% liquids	20,000 - 27,000 18% liquids
Forecast annual production - Boe/d % liquids	20,000 - 23,000 17% liquids	20,000 - 23,000 18% liquids
Est annual funds flow at 20,000 Boe/d - $ million		$70.0 - $78.0
Umbach horizontal wells drilled - gross Umbach horizontal wells completed - gross Umbach horizontal wells connected - gross	6 - 12 (6.0 - 12.0 net) 11 - 17 (11.0 - 17.0 net) 11 - 16 (11.0 - 16.0 net)	3 - 12 (3.0 - 12.0 net) 11 - 17 (11.0 - 17.0 net) 11 - 16 (11.0 - 16.0 net)

2018 Guidance History

	Chicago Daily US$/Mmbtu	Station 2 Daily Cdn$/GJ	AECO Daily Cdn$/GJ	Estimated Operations Capital $ million	Forecast Fourth Quarter Production Boe/d	Forecast Annual Production Boe/d
Nov 14, 2017	$2.80	$1.30 - $1.70	$1.80 - $2.10	$55.0 - $90.0	20,000 - 27,000	20,000 - 23,000
Mar 1, 2018	**$2.60**	**$1.05**	**$1.40**	**$55.0 - $90.0**	**20,000 – 27,000**	**20,000 – 23,000**

The continuing volatility in Western Canadian natural gas prices has been largely mitigated for Storm by increasing liquids production and through diversified natural gas sales. In 2017, liquids represented 40% of production revenue while only 34% of natural gas sales were at Western Canadian prices.

Although Storm's production in 2017 grew by 21% from 2016, growth in the second half of the year was less than expected primarily because of declining Western Canadian natural gas prices. From H1/17 to H2/17, the natural gas price declined by approximately 45% at AECO and by 70% at Station 2. This was mainly from production growing by 1 Bcf per day since the summer of 2017, storage levels that are relatively high, and export pipelines to other markets that are full (in general, too much supply and nowhere to take it). In addition, the price differential between Station 2 and AECO in H2/17 widened to -$0.80 per GJ as a result of maintenance on the Enbridge and TransCanada pipeline systems restricting takeaway out of northeast British Columbia ("NE BC"). Spot or daily natural gas prices have shown recent improvement with AECO averaging approximately $2.00 per GJ and Station 2 averaging approximately $1.75 per GJ to date in 2018 (increases of 34% and 157% respectively versus H2/17). The differential between

Station 2 and AECO has narrowed with the completion of the TCPL Towerbirch expansion which increased flows out of NE BC. Spot or daily prices have been stronger than the forward strip with strong physical demand from a cold winter, rising oil sands demand, and higher electricity generation as coal plants are decommissioned. In addition, there has been a year-over-year decrease in rigs drilling for natural gas which likely will reduce supply later in 2018.

Incremental production growth above Storm's firm transportation capacity (102 Mmcf per day sales or 20,000 to 21,000 Boe per day) is primarily directed to Station 2 and growth will continue to be contingent on the natural gas price at Station 2. Capital investment has been designed to be flexible where activity and production growth can be rapidly increased if supported by the natural gas price. At Umbach, additional compression can be installed quickly plus there are currently four completed horizontal wells that can be turned on and another five standing horizontal wells awaiting completion (all longer wells).

Storm's business plan continues to be focused on adding value by converting the multi-year drilling inventory in the Montney into funds flow growth while generating reasonable risk-adjusted rates of return. Although the current forward strip for Western Canadian natural gas prices makes this challenging, the significant improvement in liquids prices over the last 12 months has resulted in several alternatives being identified for growing funds flow by increasing liquids production.

Liquids production will be increased by continuing to drill wells in areas where higher condensate-gas ratios can be realized (Nig and Fireweed land blocks) and can also come from adding infrastructure to increase plant NGL recoveries at Umbach. Current liquids recovery from the liquids-rich Montney is less than optimal and either adding or redirecting raw gas to access a shallow-cut refrigeration process is being evaluated which would increase NGL recovery from the raw gas by approximately 100% to 125%.

Partially mitigating the decline in Western Canadian natural gas prices, Storm's capital efficiencies are expected to improve based on preliminary results from recent longer horizontal wells that are more than 2,000 meters in length (approximately 60% longer than wells completed in 2014 to 2016). Rates and reserves are expected to increase in proportion to the added length while the total well cost is increasing by 15% to 25%.

Maintaining production at current levels would also add value as debt would be reduced with maintenance capital being less than estimated funds flow at current strip pricing for 2018 and 2019. The estimated capital required to maintain production is $55.0 million to $60.0 million in 2018 and $35.0 million to $40.0 million in 2019. This option is less desirable as it adds value at a slower rate versus growing production and/or increasing liquids production.

Results from 2017 show that Storm's business plan works at low natural gas prices. In addition, the large, higher quality, liquids-rich asset in the Montney at Umbach offers alternatives for growth that are less dependent on natural gas pricing. For 2018, production is expected to grow by a minimum of 25% year over year to average 20,000 Boe per day. Existing infrastructure will support further growth to 27,000 Boe per day with the timing to do so dependent on natural gas prices. For 2019, the focus will be to identify ways to grow funds flow by increasing liquids production which could come from adding infrastructure and/or drilling wells in areas with higher condensate-gas ratios.

In closing, I would like to thank Storm's employees for their hard work which has resulted in record levels of production and significant growth in funds flow while continuing to improve capital efficiencies and reduce costs. In addition, the invaluable advice, guidance and support provided by Storm's Board of Directors continues to be much appreciated.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

March 1, 2018

Boe Presentation – For the purpose of calculating unit revenues and costs, natural gas is converted to a barrel of oil equivalent (“Boe”) using six thousand cubic feet (“Mcf”) of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel (“Bbl”) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Mboe means 1,000 Boe.

Oil and Gas Metrics - Oil and gas metrics, including FD&A, recycle ratio, FDC, and reserves life index or RLI, do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods.

Initial Production Rates - References to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

Forward-Looking Statements – Such statements made in this report are subject to the limitations set out in Storm’s Management’s Discussion and Analysis dated March 1, 2018 for the three months and year ended December 31, 2017.

RESERVES AT DECEMBER 31, 2017

Storm's year-end reserve evaluation effective December 31, 2017 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 23, 2018. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2017 was used to determine estimates of net present value ("NPV"). Storm's Reserves Committee, which is made up of independent and appropriately qualified directors, has reviewed and approved the evaluation prepared by InSite, and the report of the Reserves Committee has been accepted by the Company's Board of Directors.

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). In addition to the information disclosed in this report, more detailed information will be included in Storm's Annual Information Form for the year ended December 31, 2017 (the "AIF").

Summary

- Reserve additions in 2017 replaced 143% of production for proved developed producing ("PDP"), 351% for total proved ("1P") and 424% for total proved plus probable ("2P").
- 2P reserves include 643 Bcf of natural gas and 22 Mmbbl of NGL at year-end 2017. The NGL component includes 62% condensate (13.5 Mmbbl), 23% butane (5.0 Mmbbl) and 15% propane (3.3 Mmbbl).
- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $5.76 per Boe for PDP, $3.06 per Boe for 1P and $1.27 per Boe for 2P.
- Technical revisions increased PDP reserves by 3,342 Mboe (13%), 1P reserves by 10,949 Mboe (14%) and 2P reserves by 13,976 Mboe (13%). PDP revisions were primarily due to well performance exceeding the InSite forecast from the previous year, while 1P and 2P revisions were due to using longer horizontal wells.
- Breaking down 2P reserves by area, 99.4% is at Umbach, 0.3% is at the HRB and 0.3% is at Grande Prairie.
- Future development costs ("FDC") were $412 million on a 1P basis and $481 million on a 2P basis and are fully financeable from forecast revenue and production within five years which complies with the Canadian Oil and Gas Evaluation ("COGE") Handbook.
- FDC declined from last year with longer horizontal wells being recognized for future drilling locations in the Montney at Umbach. This reduced the total number of locations while reserves per location were increased.
- At Umbach there are 78.6 net 2P future horizontal drills assigned an average of 6.2 Bcf gross raw gas (last year was 86.4 net 2P locations with 4.5 Bcf gross raw gas).
- Wells drilled in 2017 were assigned an average of 6.6 Bcf gross raw gas on a 2P basis.
- At Umbach, 2P reserves were recognized in the upper Montney on 22% or 33.5 net sections of Storm's 155 net sections in the area (an increase of 0.8 net sections from last year). DPIIP averages 45 Bcf gross raw gas per section in the upper Montney (total net DPIIP 1.5 Tcf on 33.5 net sections). Forecast recovery of DPIIP totals 52% for 2P reserves.
- FDC includes $55.0 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $53.0 million net for future infrastructure expansion).

- The estimated cost to drill and complete a future Montney horizontal well at Umbach was $4.8 million compared to $4.5 million for the previous year (actual cost in 2017 was $4.2 million).

(1) The all-in calculation reflects the result of Storm's entire capital investment program as it takes into account the effect of acquisitions, dispositions and revisions, as well as the change in FDC.

INFORMATION REGARDING DISCLOSURE ON OIL AND GAS RESERVES AND RESOURCES

All amounts are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("Boe") based on 6 Mcf:1 Boe. The Boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not recognize a value equivalent at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. Production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, unless otherwise stated. Unless otherwise specified, all reserves volumes are based on "company gross reserves" using forecast prices and costs. The oil and gas reserves statement for the year ended December 31, 2017, which will include complete disclosure of oil and gas reserves and other information in accordance with NI 51-101, will be contained within the AIF which will be available on SEDAR.

References to estimates of oil and gas classified as DPIIP are not, and should not be confused with, oil and gas reserves.

Gross Company Interest Reserves as at December 31, 2017
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	167,747	5,771	33,729
Proved non-producing	3,706	92	710
Total proved developed	171,453	5,863	34,439
Proved undeveloped	314,872	10,700	63,179
Total proved	486,325	16,563	97,617
Probable additional	156,390	5,281	31,346
Total proved plus probable	642,715	21,844	128,963

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2017
(Gross company interest reserves before deduction of royalties payable)

	6:1 Oil Equivalent (Mboe)			
	Proved Developed Producing	Total Proved	Probable	Proved plus Probable
December 31, 2016 - opening balance	25,395	77,097	27,096	104,192
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	11,132	16,690	2,945	19,635
Category transfer	-	-	-	-
Dispositions	-	-	-	-
Technical revisions	3,342	10,949	3,027	13,976
Economic factors	(294)	(1,271)	(1,723)	(2,994)
Production	(5,846)	(5,846)	-	(5,846)
December 31, 2017 – closing balance	33,729	97,617	31,346	128,963

Numbers in this table may not add due to rounding.

Reserve Life Index ("RLI") Using Fourth Quarter Production

	2017	2016	2015
PDP	5.2	5.2	5.3
1P	14.9	15.9	18.8
2P	19.7	21.4	25.7

Future Development Costs ("FDC")

	Proved ($M)	Proved Plus Probable ($M)
2018	60,050	64,300
2019	103,071	119,391
2020	179,781	207,352
2021	68,745	90,075
2022	-	-
Total FDC - undiscounted	411,647	481,118
Total FDC - discounted at 10%	340,908	395,976

($million)	2017	2016	2015
1P FDC	$ 412	$ 413	$ 435
2P FDC	$ 481	$ 524	$ 543

Note: InSite escalates capital costs at 2% per year after 2018.

All-in Finding, Development and Acquisition Costs ("FD&A")
(including acquisitions, dispositions and revisions)

Proved Developed Producing FD&A Cost (All-in)	2017	2016	2015	3 Year Total
Net capital investment (000s)	$ 81,685	$ 64,938	$ 71,509	$ 218,130
Total capital	$ 81,685	$ 64,938	$ 71,509	$ 218,130
Total reserve additions (Mboe)	14,180	9,424	10,956	34,560
All-in PDP FD&A cost (per Boe)	$ 5.76	$ 6.89	$ 6.53	$ 6.31

Total Proved FD&A Cost (All-in)	2017	2016	2015	3 Year Total
Net capital investment (000s)	$ 81,685	$ 64,938	$ 71,509	$ 218,130
Change in FDC (000s)	(1,127)	(22,669)	(12,275)	(36,071)
Total capital including change in FDC (000s)	$ 80,558	$ 42,269	$ 59,234	$ 182,059
Total reserve additions (Mboe)	26,366	8,501	17,517	52,384
All-in 1P FD&A cost (per Boe)	$ 3.06	$ 4.97	$ 3.38	$ 3.48

Total Proved Plus Probable FD&A Cost (All-in)	2017	2016	2015	3 Year Total
Net capital investment (000s)	$ 81,685	$ 64,938	$ 71,509	$ 218,130
Change in FDC (000s)	(42,755)	(19,395)	(63,288)	(125,438)
Total capital including change in FDC (000s)	$ 38,930	$ 45,543	$ 8,221	$ 92,692
Total reserve additions (Mboe)	30,617	8,308	16,332	55,257
All-in 2P FD&A cost (per Boe)	$ 1.27	$ 5.48	$ 0.50	$ 1.68

Finding and Development Costs ("F&D")
(excluding acquisitions, dispositions and revisions)

Total Proved F&D Cost	2017	2016	2015	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 81,685	$ 64,938	$ 95,099	$ 241,720
Change in FDC (000s)	(1,127)	(22,669)	18,604	(5,192)
Total capital including change in FDC (000s)	$ 80,558	$ 42,269	$ 113,703	$ 236,528
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	16,669	5,182	14,950	36,801
1P F&D cost (per Boe)	$ 4.83	$ 8.16	$ 7.61	$ 6.43

Total Proved Plus Probable F&D Cost	2017	2016	2015	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 81,685	$ 64,938	$ 95,099	$ 241,720
Change in FDC (000s)	(42,755)	(19,395)	30,717	(31,433)
Total capital including change in FDC (000s)	$ 38,930	$ 45,543	$ 125,816	$ 210,287
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	19,615	4,890	19,457	43,962
2P F&D cost (per Boe)	$ 1.98	$ 9.31	$ 6.47	$ 4.78

Net Present Value Summary (before tax) as at December 31, 2017

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	613,055	476,124	389,466	330,863	289,021
Proved non-producing	7,396	4,839	3,341	2,395	1,763
Total proved developed	620,451	480,963	392,806	333,258	290,784
Proved undeveloped	915,449	590,662	399,234	278,439	198,009
Total proved	1,535,899	1,071,625	792,040	611,697	488,792
Probable additional	658,780	357,091	215,918	141,347	97,907
Total proved plus probable	2,194,678	1,428,716	1,007,958	753,044	586,700

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2017

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

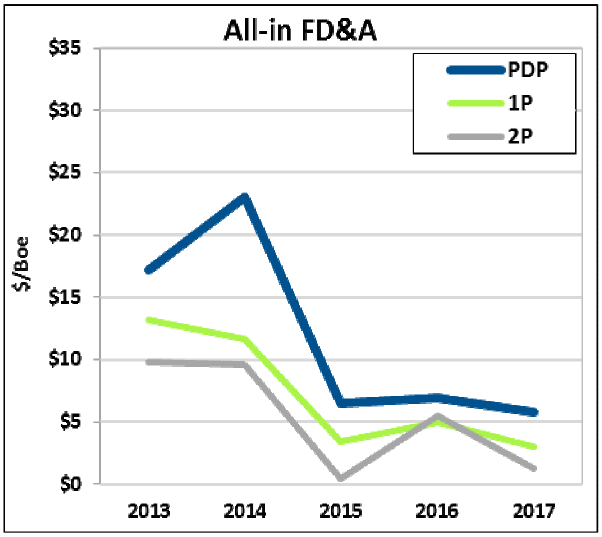
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	576,702	455,976	377,775	323,808	284,617
Proved non-producing	5,476	3,661	2,585	1,893	1,419
Total proved developed	582,178	459,637	380,360	325,701	286,036
Proved undeveloped	677,095	430,687	285,517	194,069	133,346
Total proved	1,259,272	890,324	665,877	519,770	419,382
Probable additional	488,035	263,033	157,653	102,008	69,645
Total proved plus probable	1,747,307	1,153,356	823,530	621,778	489,027

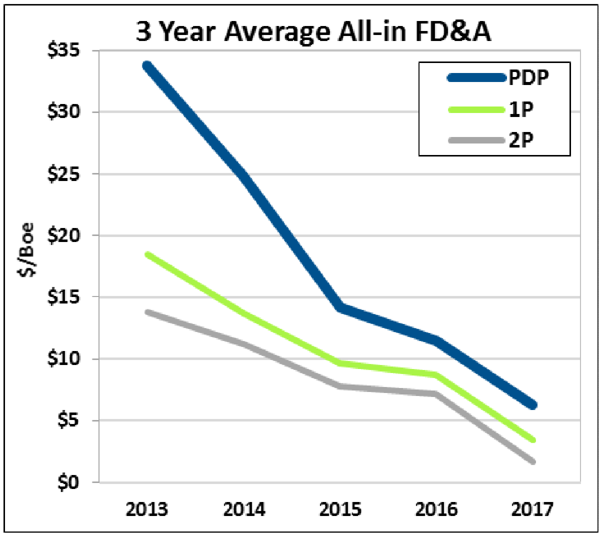
Numbers in this table may not add due to rounding.

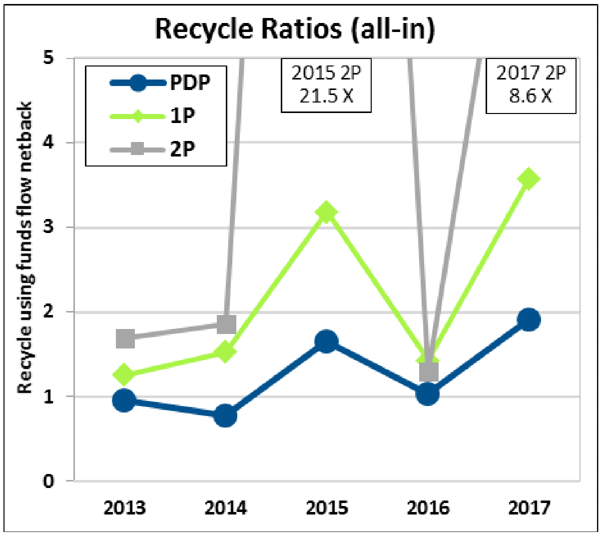
InSite Escalating Price Forecast as at December 31, 2017

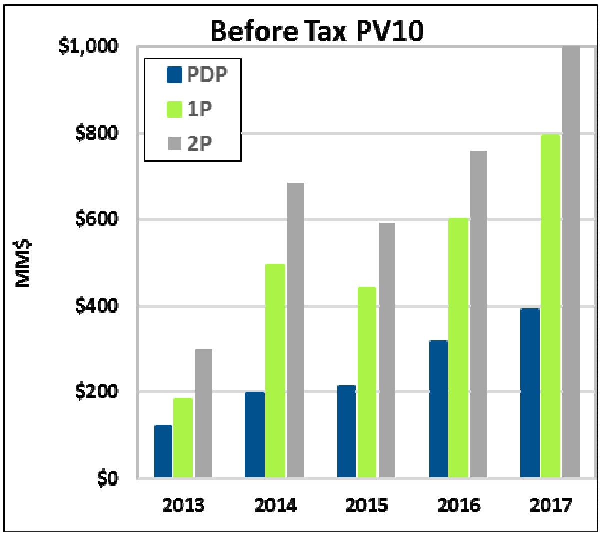
	WTI Crude Oil (US$/Bbl)	Edmonton Par Crude Oil (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)
2018	60.00	71.36	3.10	2.52
2019	62.50	73.44	3.30	2.93
2020	65.00	75.47	3.50	3.22
2021	70.00	80.49	3.70	3.51
2022	72.50	82.38	3.90	3.75

FD&A improving with better well results and economies of scale with larger facilities





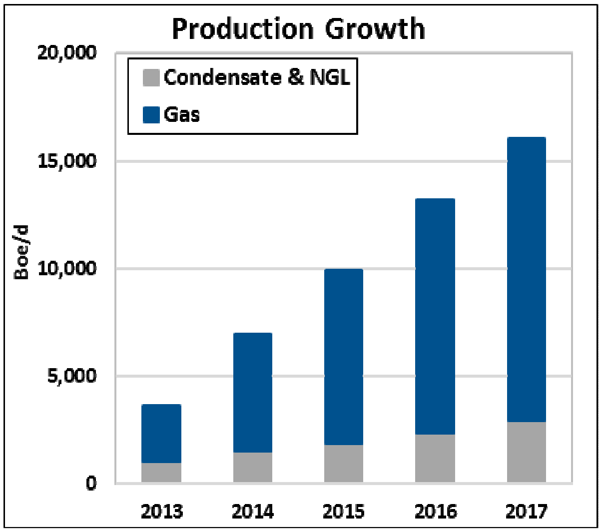


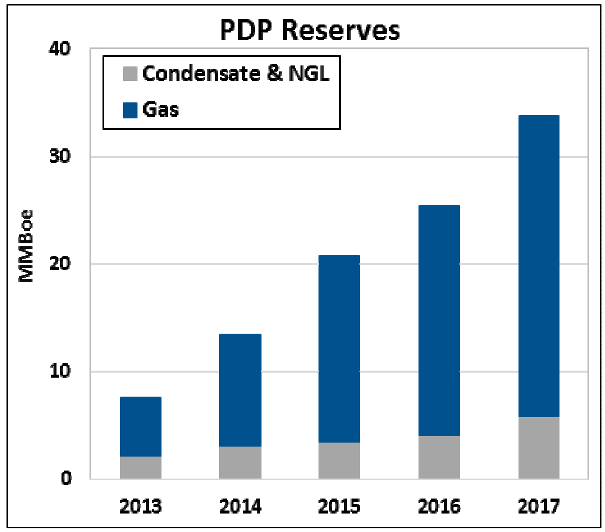


Recycle ratio improving with diversified natural gas sales, increased liquids prices and cost reductions

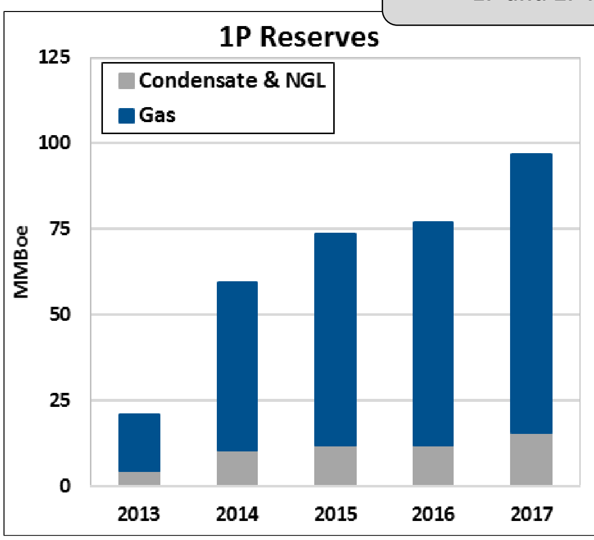
Over the last 5 years production increased 340%, or 217% on a per-share basis

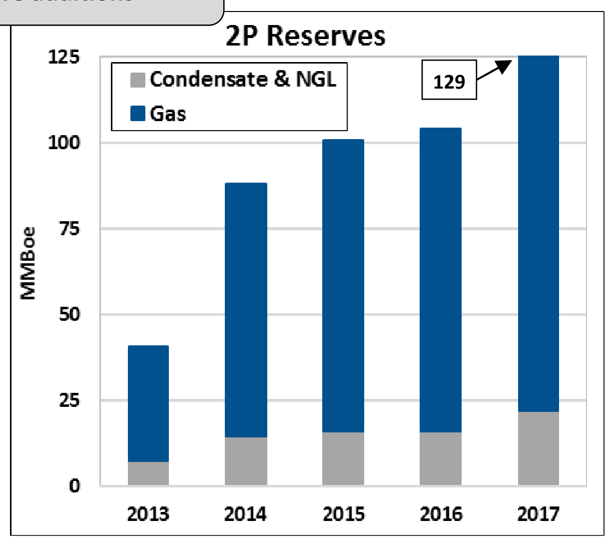
PDP reserves increasing at the same rate as production growth

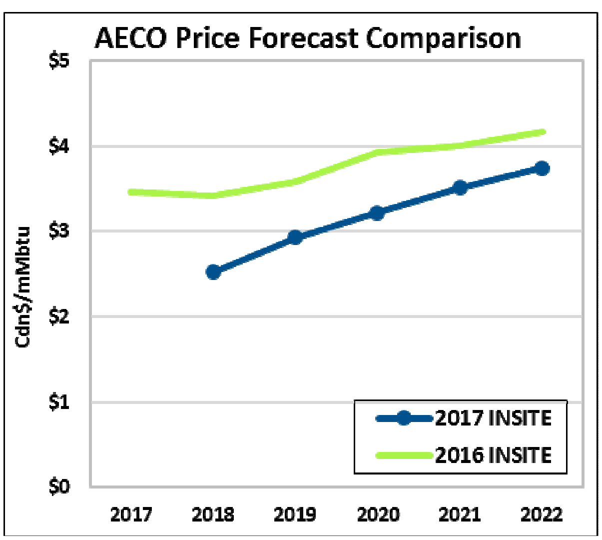


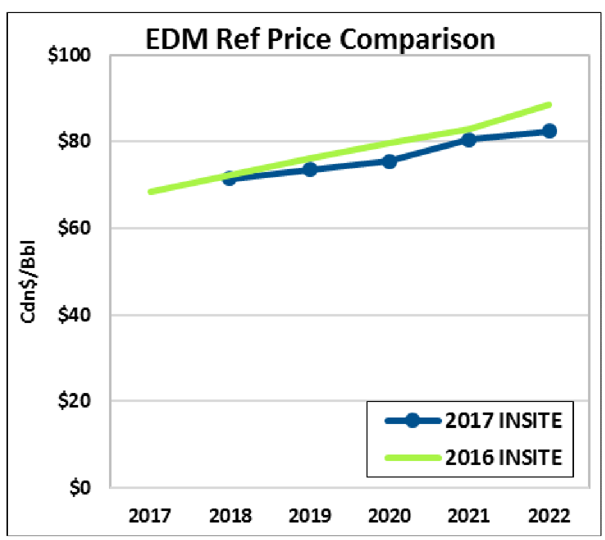


Using longer horizontal wells resulted in 1P and 2P reserve additions









MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three months and year ended December 31, 2017. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2017 and 2016, (ii) each of the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2017, and (iii) the press release issued by the Company on March 1, 2018, and other operating and financial information included in this report. All of these documents are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

The Company trades on the Toronto Stock Exchange ("TSX") under the symbol "SRX".

This MD&A is dated March 1, 2018.

See "Forward-Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 37 to 39.

BASIS OF PRESENTATION

Financial data presented below have largely been derived from the Company's audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial information for the three months ended December 31, 2017, prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the years ended December 31, 2017 and 2016. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three months and year ended December 31, 2016.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Year to December 31, 2017

Resiliency and sustainability continue to define Storm's business model. Despite seemingly endless challenges facing the Canadian energy sector, Storm's business remains sound with the Company in a position of strength both from an operational and a financial standpoint. Storm entered the year with considerable momentum reaching record production levels in early spring supported by relatively strong commodity prices. This was followed by the McMahon Gas Plant maintenance turnaround which resulted in approximately 80% of Storm's production being shut in for 39 days. Further, natural gas prices in Western Canadian markets collapsed in the second half of the year, although the Company's diversification strategy partially mitigated the exposure to low prices by maximizing sales to the Chicago market. Storm shipped approximately 70% of production in the second half of the year on the Alliance pipeline to Chicago where pricing was not affected. Most of Storm's remaining natural gas is sold at Station 2 where the price declined by approximately 65% from the first half of the year to the second half. In response, the Company deferred the start-up of new horizontal wells thus minimizing volumes sold in the Station 2 market. The deterioration of natural gas prices in Western Canada comes down to record supply levels, further exacerbated for Canadian producers by a lack of egress to other markets. With pricing reaching levels that are unsustainable for most, if not all producers, capital spending will need to be reduced industry wide, which should lead to reduced supply followed by higher prices in due course.

While representing only 18% of the Company's total production base, condensate (includes field condensate and plant pentanes) and NGL (includes butane and propane) contributed 40% to the Company's top line revenue, with continuing strength in condensate and NGL prices helping to offset the weakness in natural gas prices. As the majority of Storm's condensate and NGL revenue streams are based on crude oil reference prices, the improved fundamentals in the crude oil market help to differentiate Storm's business plan, particularly in light of the ability to focus drilling on areas of higher liquids recoveries.

Volatility in commodity prices in the second half of the year resulted in guidance being amended by the Company as set out in the table below:

2017 Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	AECO Daily (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
September 7, 2016	$3.00	$2.25	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
November 15, 2016	$3.00	$2.20	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
March 2, 2017	$3.00	$2.00	$2.50	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
May 15, 2017	$3.00	$2.10	$2.50	$75.0 - $80.0	19,000 - 21,000	17,000 - 18,000
August 15, 2017	$2.90	$2.00	$2.45	$75.0 - $95.0	19,000 - 21,000	16,500 - 18,000
November 14, 2017	$2.90	$1.70	$2.10	$82.0	18,000 - 19,000	16,200
Actual 2017 Results	**$2.88**	**$1.48**	**$2.04**	**$81.7**	**17,936**	**16,017**

Commodity prices were stable for the first half of the year resulting in only minor changes to Storm's guidance. In mid-August, under the assumption that Western Canadian natural gas prices would recover into the fourth quarter, the Company provided for the option of an increased capital program to accelerate drilling and completions along with infrastructure initiatives. However, upon confirmation of sustained weakness in Station 2 prices, capital investment was maintained close to previously contemplated levels.

Storm continues to manage its production growth in response to ongoing volatility in natural gas prices, while ensuring firm transportation and processing commitments are being met. Nevertheless, with significant financial flexibility, improving well results at Umbach, and an inventory of wells awaiting completion, Storm can react quickly and accelerate production growth in the event of a sustained improvement in Western Canadian natural gas prices.

Debt including working capital deficiency at year end amounted to $106 million, or 1.2 times annualized fourth quarter 2017 funds flow, with $101 million drawn on the Company's $165 million credit facility.

Year over year, total production grew by 21%, all from the Umbach area in northeast British Columbia. Growth in production would have been higher; however, production was restricted at various times in the year due to low natural gas prices while also affected by the McMahon Gas plant turnaround. Further, the Company delayed the start-up of new horizontal wells in response to low natural gas prices.

Year-over-year production costs per Boe fell by 11%, while the total of general and administrative and interest and finance costs per Boe fell by 2%. These cost reductions, coupled with a 32% increase in realized pricing and the aforementioned increase in production volumes, drove a year-over-year funds flow per Boe increase of 54%. These improvements would have been more pronounced had it not been for the McMahon Gas Plant turnaround. Given the improved pricing scenario relative to 2016, Storm's active hedging program resulted in a small realized hedging loss of $2.4 million compared to a realized hedging gain of $4.5 million achieved in the prior year.

Storm's 2017 capital program was focused on the Umbach property, with the program pushing development to the northwest and southern parts of the Company's lands in areas where condensate content is expected to be higher. The Company incurred net capital expenditures of $81.7 million, the bulk of which was spent on drilling and completions.

A total of $59.9 million was spent on drilling and completions and $18.5 million on infrastructure. Sixteen wells (100% working interest) were drilled in the year with 13 wells being brought on production, leaving an inventory of 12 horizontal wells (12.0 net) that had not started producing at the end of 2017 (includes two completed wells). Storm can thus replace production declines, or add production in 2018, at a relatively modest cost. Commodity prices and funds flow will continue to drive the Company's capital program at Umbach in 2018. The capital program for 2018 is flexible and is subject to amendment throughout the year. Storm's longer-term business plan to continue growing funds flow will not change, what may change is timing of execution.

The new field compression facility that came on stream in January 2017 increased compression capacity to 115 Mmcf of raw gas per day. As previously communicated, the new facility is expected to be twinned in due course for an incremental cost of $7 million. Twinning of the new facility has the potential to increase Storm's production base from current levels to volumes of approximately 27,000 Boe per day.

Quarter Ending December 31, 2017

The fourth quarter of 2017 was the Company's strongest quarter, financially, of 2017. Production was 35% higher than the fourth quarter of 2016 and 18% higher compared to the third quarter of 2017. Revenue from product sales for the quarter was 33% higher than the prior year due to higher production levels. Revenue per Boe was essentially flat with the fourth quarter of 2016 as lower natural gas prices were offset by higher condensate and NGL prices. Revenue per Boe was 23% higher than the immediately preceding quarter. Production increased from just under 17,000 Boe per day for the month of October to just over 19,000 Boe per day for the month of December, with production to date in 2018 averaging just under 20,000 Boe per day based on field estimates. Increased production in December 2017 was driven by relatively strong natural gas prices in the Chicago market coupled with continued strength in condensate and NGL prices.

Funds flow for the quarter totaled $21.3 million, approximately 78% higher than the same period in the prior year and 62% greater than the third quarter of 2017. Increased funds flow over the preceding quarter resulted primarily from improved pricing and higher production levels in the current period. There was an improvement in pricing across all products, most notably a material uplift in condensate and NGL prices. Using annualized funds flow for the fourth quarter, the ratio of year-end debt including working capital deficiency to funds flow amounted to 1.2 times.

Capital expenditures for the quarter totaled $26.1 million. Included in this amount are drilling and completion costs of $21.4 million, corresponding to the drilling of seven wells along with the completion of three wells in the quarter. Facility, equipping and gathering costs totaled $3.8 million.

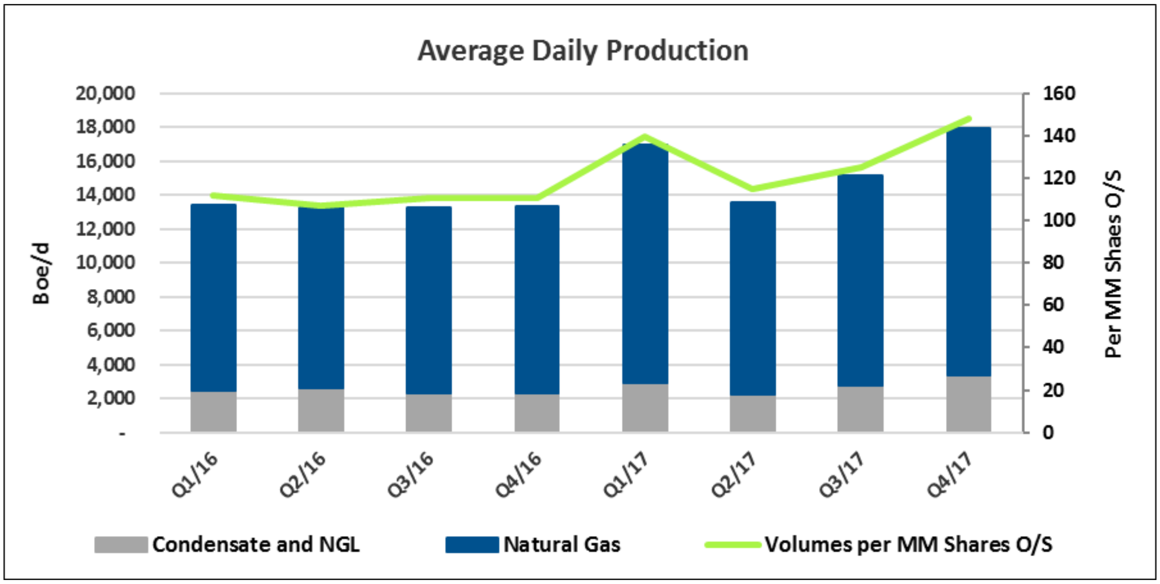
During the fourth quarter of 2017, the Company's bank syndicate confirmed Storm's bank facility at $165 million, which was 61% drawn at the end of the fourth quarter. The annual review will take place prior to April 27, 2018.

Production and Revenue

Average Daily Production

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Natural gas (Mcf/d)	87,375	66,173	78,521	65,478
Condensate (Bbls/d)	1,914	1,381	1,685	1,303
Natural gas liquids (Bbls/d)	1,460	910	1,245	1,003
Total (Boe/d)	17,936	13,320	16,017	13,219
Natural gas weighting	81%	83%	82%	83%
Condensate weighting	11%	10%	10%	10%
Natural gas liquids weighting	8%	7%	8%	7%

Production increases for natural gas, condensate and NGL, when compared to both periods in 2016, came from growth at Umbach where the Company started production from five new 100% working interest wells during the fourth quarter of 2017 and 13 new 100% working interest wells during the year ended December 31, 2017.



Storm's production increased 27% from the fourth quarter of 2016 to the first quarter of 2017 as a result of the commissioning of the Company's third field compression facility in January. Production volumes for the second and third quarters of 2017 were affected by a 39-day turnaround at the McMahon Gas Plant. Production increased in the fourth quarter of 2017; however, as a result of the deterioration of Western Canadian gas prices, production was not maximized and was maintained at a level to meet firm processing and transportation commitments.

Daily production per million shares outstanding at the end of 2017 averaged 132 Boe per day, compared to 109 Boe per day in 2016, an increase of 21%. Daily production per million shares for the fourth quarter of 2017 averaged 148 Boe per day compared to 110 Boe per day for the fourth quarter of 2016, an increase of 35%.

Average Selling Prices[(1)]

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Natural gas – Mcf	$ 2.26	$ 2.86	$ 2.58	$ 2.05
Condensate – Bbl	69.53	57.17	61.80	49.34
Natural gas liquids – Bbl	33.29	18.64	25.15	12.51
Per Boe	$ 21.12	$ 21.42	$ 21.09	$ 15.97

(1) Before realized gains and losses on commodity price contracts.

On a per-Boe basis, the Company's average realized price for 2017 increased by 32% when compared to 2016, driven by gains across all three product streams, most notably NGL where realized pricing increased 101% year over year.

On a per-Boe basis, the Company's average realized price for the fourth quarter of 2017 was consistent with the same period in 2016, as a lower realized natural gas price was almost completely offset by improved condensate and NGL realizations.

Benchmark Prices

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year ended Dec. 31, 2017	Year ended Dec. 31, 2016
Natural gas				
Chicago monthly index ($US/Mmbtu)	2.92	3.00	3.04	2.49
Chicago daily index ($US/Mmbtu)	2.83	2.97	2.88	2.47
AECO monthly index (Cdn$/GJ)	1.85	2.67	2.30	1.98
AECO daily index (Cdn$/GJ)	1.60	2.93	2.04	2.05
Station 2 (Cdn$/GJ)	0.53	2.27	1.48	1.64

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year ended Dec. 31, 2017	Year ended Dec. 31, 2016
Crude Oil				
WTI (US$/Bbl)	55.40	49.29	50.95	43.32
Edmonton light oil (Cdn$/Bbl)	69.02	61.58	62.91	52.99
Exchange rate (US$/Cdn$)	0.79	0.75	0.77	0.75

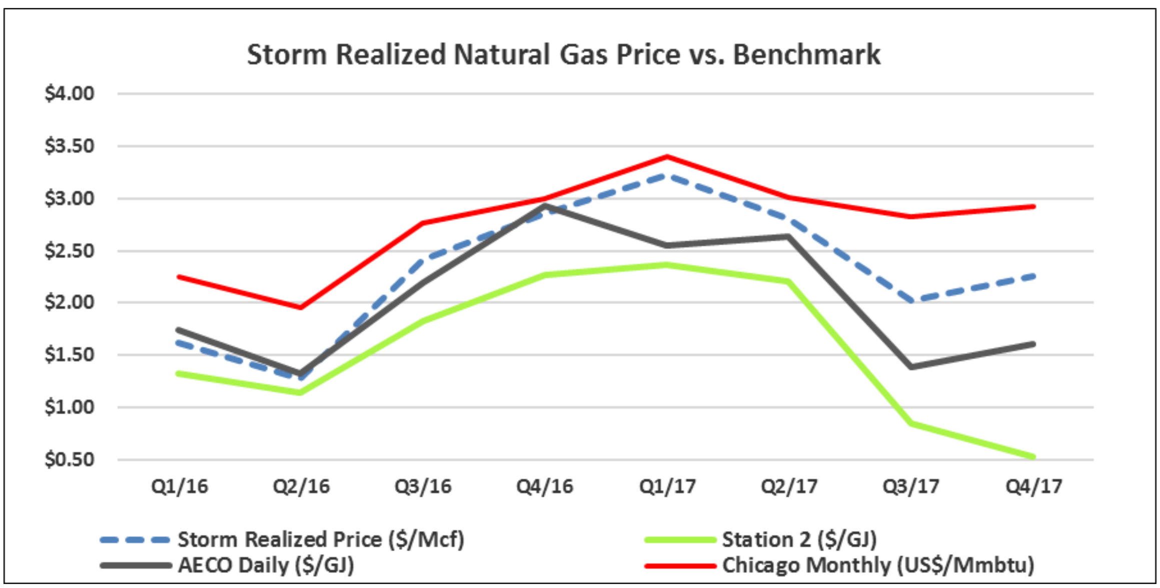
Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate, varying transportation costs to each market and the higher heat content of the Company's natural gas.

During the summer of 2017, AECO and Station 2 prices fell considerably and remained weak for the remainder of the year due to a combination of factors on the TransCanada Pipelines Limited ("TCPL") NGTL and Enbridge (Spectra) pipeline systems. The most notable were a change in the methodology by which TCPL restricts gas flows during maintenance and continued robust supply growth from the Western Canadian Sedimentary Basin leading to a lack of egress for natural gas molecules, with production levels hitting a high for the year in December 2017. Western Canadian natural gas prices are expected to remain volatile for the foreseeable future.

The Company's production during the fourth quarter and year ended December 31, 2017 was sold as follows:

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year ended Dec. 31, 2017	Year ended Dec. 31, 2016
Chicago monthly index price(1)	45%	33%	45%	41%
Chicago daily index price(1)	25%	33%	21%	28%
Station 2 daily spot price	24%	25%	28%	18%
AECO daily index price(1)	-	4%	1%	12%
Alliance Transfer Point ("ATP")	6%	5%	5%	1%
Total	100%	100%	100%	100%

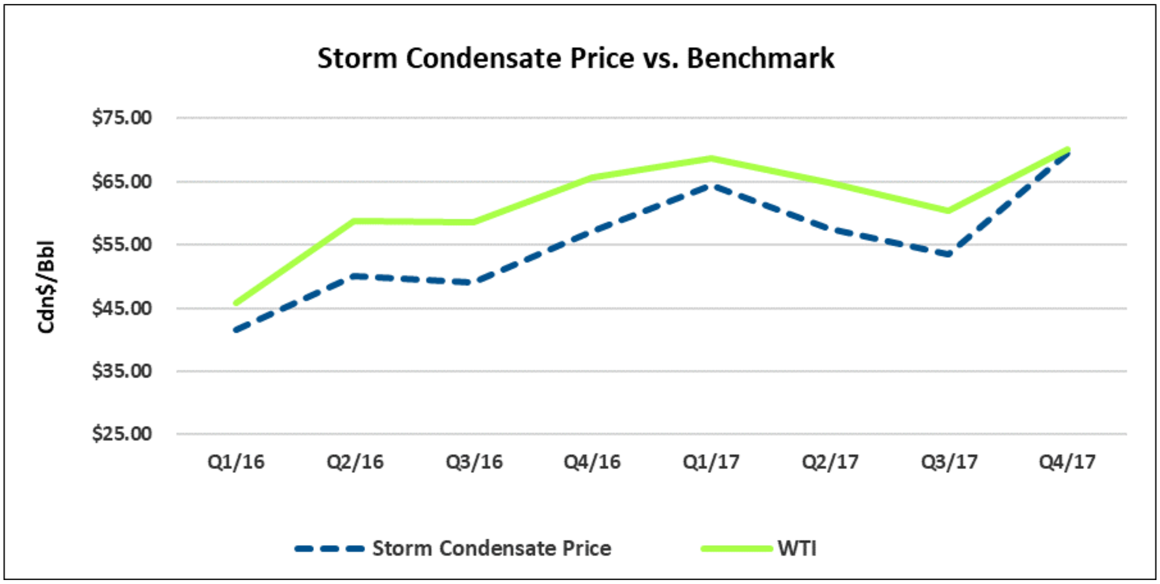
(1) Adjusted for marketing-related fees.

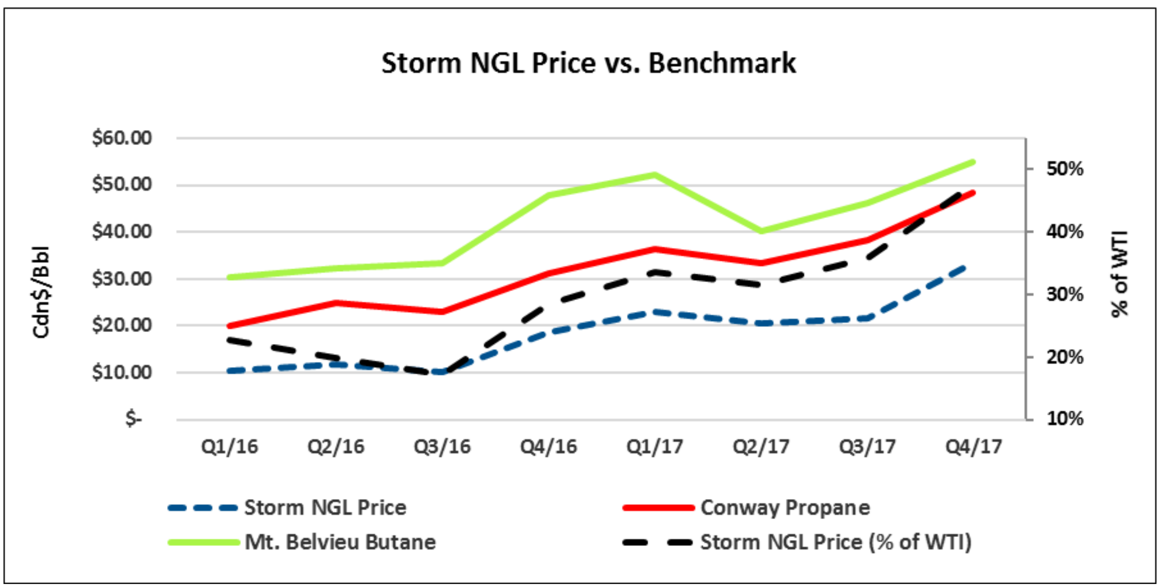


Natural gas sold with reference to the Chicago index price is subject to a pricing reduction equal to the pipeline tariff to Chicago (approximately Cdn$1.30 per GJ) as title to the natural gas transfers at the processing plant in British Columbia.

Storm's realized natural gas price for 2017 was $2.58 per Mcf. With 66% of the Company's production sold in Chicago, Storm's basket realized natural gas price benefited from stronger Chicago pricing, which was partially offset by lower Station 2 pricing. As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was 303% higher than Station 2 pricing in the fourth quarter of 2017 and 65% higher than Station 2 pricing in

2017. Station 2 pricing in the second half of 2017 was quite simply uneconomic and likely below the cost of replacement for all producers.





Storm's liquids stream in 2017 contained approximately 58% condensate, which is generally priced with reference to benchmark pricing for Edmonton light oil. Storm received an average price of $61.80 per barrel for condensate, a 25% increase from the price realized in 2016. In 2017, WTI averaged US$50.95 per barrel and Edmonton light oil was Cdn$62.91 per barrel, resulting in a US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$3.17 per barrel, compared to Cdn$4.39 per barrel in 2016. The realized price for NGL, excluding condensate, in 2017 increased by over 100% relative to 2016. The increase in realized NGL prices was primarily due to a material recovery in propane pricing year over year. Propane prices hit three-year highs in 2017 due to tight supplies with inventory levels running below historical averages.

Increasing natural gas production at Umbach has resulted in higher value condensate becoming a significant contributor to revenue. The contribution from this revenue stream comprised 10% of Boe production but amounted to 31% of revenue from product sales in 2017.

Revenue from Product Sales[1]

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Natural gas	$ 18,130	$ 17,423	$ 73,860	$ 49,151
Condensate	12,243	7,259	38,015	23,541
Natural gas liquids	4,471	1,562	11,431	4,591
Total	$ 34,844	$ 26,244	$ 123,306	$ 77,283
% of Total Revenue by Product Type				
Natural gas	52%	66%	60%	64%
Condensate and natural gas liquids	48%	34%	40%	36%
Total	100%	100%	100%	100%

(1) Before realized gains and losses on commodity price contracts.

Revenue from product sales for 2017 increased by 60% when compared to 2016 primarily as a result of per-Boe prices which increased 32% while production volumes increased 21%. For the three month period, the increase in year-over-year revenue from product sales was predominantly due to production volumes increasing 35%.

A reconciliation of year-over-year and quarter-over-quarter revenue changes is as follows:

	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – 2016	$ 49,151	$ 23,541	$ 4,591	$ 77,283
Effect of changes in production	9,630	6,823	1,093	17,546
Effect of changes in average product prices	15,079	7,651	5,747	28,477
Revenue from product sales - 2017	$ 73,860	$ 38,015	$ 11,431	$ 123,306

	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q4 2016	$ 17,423	$ 7,259	$ 1,562	$ 26,244
Effect of changes in production	5,584	2,808	941	9,333
Effect of changes in average product prices	(4,877)	2,176	1,968	(733)
Revenue from product sales – Q4 2017	$ 18,130	$ 12,243	$ 4,471	$ 34,844

Commodity Price Risk Management

	Year Ended Dec. 31, 2017		Year Ended Dec. 31, 2016	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (2,597)	$ 25,814	$ 1,260	$ (23,894)
Liquids[1]	239	$ (1,187)	3,245	$ (6,245)
Gain (loss) on commodity price contracts	$ (2,358)	$ 24,627	$ 4,505	$ (30,139)

	Three Months to Dec. 31, 2017		Three Months to Dec. 31, 2016	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ 1,014	$ 3,744	$ (2,119)	$ (11,192)
Liquids[1]	(329)	$ (4,551)	345	$ (2,733)
Gain (loss) on commodity price contracts	$ 685	$ (807)	$ (1,774)	$ (13,925)

(1) Liquids includes field condensate, plant pentanes, butane and propane.

The term liquids above refers to crude oil contracts. Although the Company has no crude oil production, condensate and a portion of the NGL stream is priced with reference to crude oil and, as a result, the Company enters into crude oil contracts as a proxy for a condensate and NGL hedge.

The realized gain (loss) on commodity price contracts consists of the portion of contracts that have settled in cash during the reporting period.

The unrealized gain (loss) on commodity price contracts is a non-cash charge representing the change in the mark-to-market position of unexpired contracts at the end of the period.

The Company had in place the following commodity price contracts at the date of this report:

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Jan – Feb 2018	4,000 Mmbtu	Chicago US$2.815/Mmbtu
Jan – Dec 2018	7,500 Mmbtu	Chicago Cdn$3.70/Mmbtu
Mar – Dec 2018	4,000 Mmbtu	Chicago Cdn$3.55/Mmbtu
Jan – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.01/Mmbtu
Jul – Dec 2018	12,000 Mmbtu	Chicago Cdn$3.51/Mmbtu
Jul – Dec 2018	3,000 Mmbtu	Chicago US$2.65/Mmbtu
Jan – Jun 2019	8,000 Mmbtu	Chicago Cdn$3.50/Mmbtu
Jan – Jun 2019	3,000 Mmbtu	Chicago US$2.65/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Crude Oil Collars		
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	450 Bbls	$62.78 - $71.67 Cdn$/Bbl
Jan – Jun 2019	300 Bbls	$64.00 - $72.37 Cdn$/Bbl
Crude Oil Swaps		
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Propane Swaps		
Jan – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl

During 2017, the Company realized a loss from commodity price contracts in the amount of $2.4 million compared to a gain of $4.5 million in 2016. The majority of the loss recognized for 2017 related to natural gas differential swaps between Chicago and AECO that expired at the end of 2017, partially offset by gains from Chicago and AECO swaps. During the fourth quarter of 2017, the Company realized a gain from commodity price contracts settled during the quarter in the amount of $0.7 million, compared to a loss of $1.8 million in the fourth quarter of 2016.

The fair market value of contracts outstanding at December 31, 2017 was a net asset position of $2.5 million (December 31, 2016 – net liability of $22.2 million) and is included in current and non-current assets or current and non-current liabilities, as appropriate. For 2017, the change in fair market value resulted in an unrealized mark-to-market gain of $24.6 million and an unrealized mark-to-market loss of $0.8 million for the three months ended December 31, 2017 (2016 – unrealized mark-to-market losses of $30.1 million and $13.9 million, respectively) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

Physical Delivery Sales Contract

The Company also enters into physical delivery sales contracts from time to time to manage commodity price risk. These contracts are considered normal executory contracts and are not recognized in the consolidated statement of income (loss) and comprehensive income (loss) until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Jan 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Royalties

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 1,046	$ 1,217	$ 6,974	$ 3,823
Percentage of revenue from product sales	3.0%	4.6%	5.7%	4.9%
Per Boe	$ 0.63	$ 0.99	$ 1.19	$ 0.79

Royalties as a percentage of revenue from product sales, increased to 5.7% in 2017 from 4.9% in 2016. Royalties increased due to higher production revenue driven by an increase in commodity prices, partially offset by an increase in wells eligible for the BC Deep Well Royalty Credit Program, which reduces the royalty rate on eligible wells to 6% for approximately two years. In 2017, 35 wells qualified for the 6% royalty rate compared to 24 wells in 2016. Royalties for the three months ended December 31, 2017 decreased due to the receipt of an infrastructure royalty credit and an increase in the number of wells eligible for the 6% royalty rate.

Storm has remaining infrastructure royalty credits of $6.7 million that will reduce future royalties. The timing of receipt and accounting recognition of future credits is dependent on commodity prices and production levels from individual wells and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially, as these credits are earned.

Production Costs

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 9,376	$ 8,518	$ 35,283	$ 32,794
Per Boe	$ 5.68	$ 6.95	$ 6.04	$ 6.78

Total production costs for the three months and year ended December 31, 2017 increased by 10% and 8%, respectively, when compared to the same periods of 2016. The increase in total production costs is due to increased production at Umbach, partially offset by lower natural gas processing fees as a result of a new processing agreement that came into effect on January 1, 2017. The percentage increase in production costs is considerably less than the percentage increase in production volumes, indicative of the Company's efforts to reduce per-Boe costs.

Production costs per Boe for the fourth quarter of 2017 decreased 18% when compared to the fourth quarter of 2016 due in part to lower per-unit processing costs associated with the aforementioned new processing agreement. Production costs per Boe for 2017 decreased by 11% when compared to 2016, also as a result of the lower per-unit processing fee and with production growth reducing the fixed cost component of per-Boe costs. These decreases to production costs per Boe were muted by the additional costs associated with production being reduced during the 39-day maintenance turnaround at the McMahon Gas Plant which meant that the firm processing commitment was not fully utilized.

Transportation Costs

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 1,134	$ 673	$ 4,446	$ 2,186
Per Boe	$ 0.69	$ 0.55	$ 0.76	$ 0.45

Transportation costs include pipeline tariffs for natural gas sold at Station 2, as well as trucking costs for wellhead condensate. Total transportation costs for 2017 increased by 103% from 2016, and by 69% per Boe. Transportation costs for the fourth quarter of 2017 increased by $0.5 million when compared to the fourth quarter of 2016 while per-Boe transportation costs increased 25%. Higher transportation costs in 2017 were due to an increase in natural gas volumes sold at Station 2 and higher condensate production. Natural gas sold at Station 2 increased from 18% of total natural gas production volumes in 2016 to 28% in 2017. Condensate production in 2017 increased 29% over the same period in 2016. In addition to the higher Station 2 and condensate volumes, 2017 was also affected by increased trucking costs attributable to extended road bans relative to 2016.

As the sales point for natural gas shipped on the Alliance Pipeline is at the gas processing facilities in British Columbia, the sales price received by the Company is net of the cost of transporting natural gas to Chicago and is thus captured on a net basis as part of revenue from product sales.

In conjunction with the adoption of IFRS 15 on January 1, 2018, transportation costs will increase, with an equivalent increase to revenue, as tolls on the Alliance Pipeline will be presented on a gross basis. Had the Alliance Pipeline tolls been reported on a gross basis for the periods presented above, transportation costs would have been $9.8 million for the fourth quarter of 2017 ($7.4 million for the fourth quarter of 2016) and $34.0 million for 2017 ($28.0 million for 2016). Revenue from product sales would increase by the same amounts.

Field Operating Netbacks

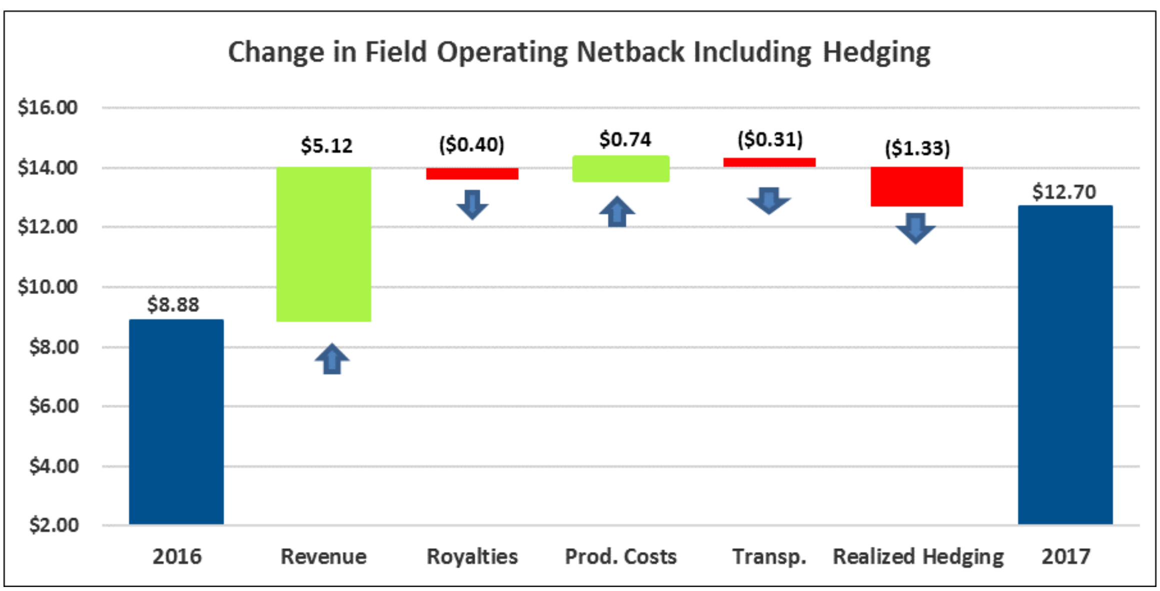
Details of field netbacks, measured per commodity unit produced, are as follows:

Year Ended December 31, 2017 and 2016

	Year Ended December 31, 2017			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.58	$ 61.80	$ 25.15	$ 21.09
Royalties	(0.09)	(5.59)	(2.31)	(1.19)
Production costs	(1.23)	-	-	(6.04)
Transportation costs	(0.07)	(4.16)	-	(0.76)
Field operating netback	$ 1.19	$ 52.05	$ 22.84	$ 13.10
Realized (loss) gain on commodity price contracts	(0.09)	0.39	-	(0.40)
Field operating netback including hedging	$ 1.10	$ 52.44	$ 22.84	$ 12.70

	Year Ended December 31, 2016			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.05	$ 49.34	$ 12.51	$ 15.97
Royalties	(0.05)	(4.73)	(1.25)	(0.79)
Production costs	(1.37)	-	-	(6.78)
Transportation costs	(0.04)	(2.82)	-	(0.45)
Field operating netback	$ 0.59	$ 41.79	$ 11.26	$ 7.95
Realized gain on commodity price contracts	0.05	6.80	-	0.93
Field operating netback including hedging	$ 0.64	$ 48.59	$ 11.26	$ 8.88

The 2017 field operating netback increased by 65% (43% increase including hedging) compared to 2016.



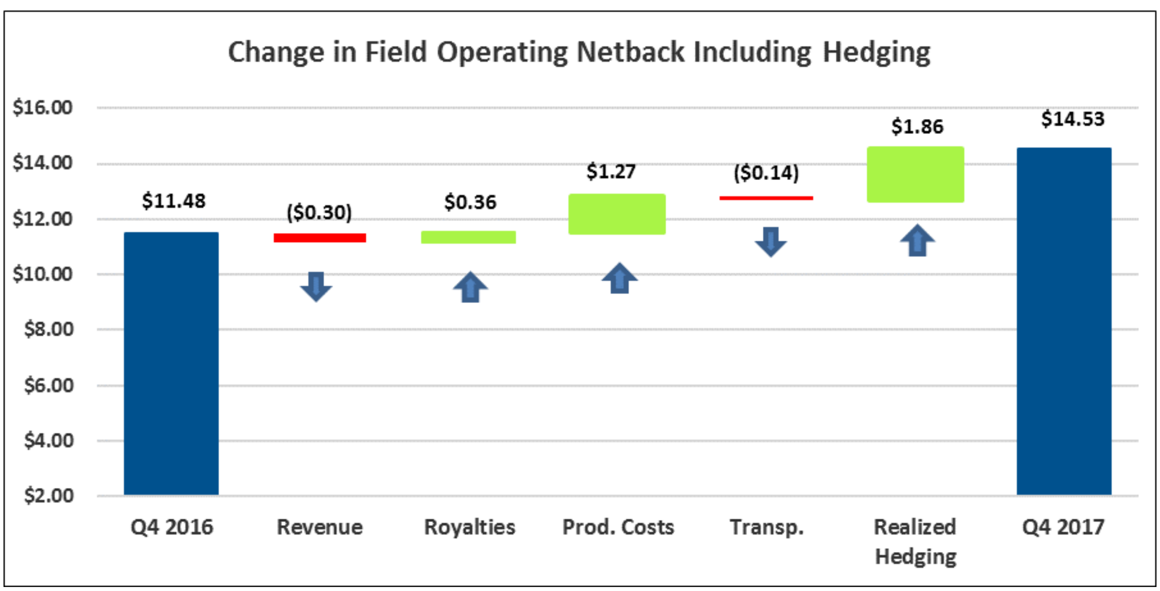
Three Months Ended December 31, 2017 and 2016

	Three Months Ended December 31, 2017			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.26	$ 69.53	$ 33.29	$ 21.12
Royalties	0.05	(5.96)	(2.99)	(0.63)
Production costs	(1.17)	-	-	(5.68)
Transportation costs	(0.05)	(4.09)	-	(0.69)
Field operating netback	$ 1.09	$ 59.48	$ 30.30	$ 14.12
Realized gain (loss) on commodity price contracts	0.13	(1.87)	-	0.41
Field operating netback including hedging	$ 1.22	$ 57.61	$ 30.30	$ 14.53

	Three Months Ended December 31, 2016			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.86	$ 57.17	$ 18.64	$ 21.42
Royalties	(0.05)	(5.82)	(2.03)	(0.99)
Production costs	(1.40)	-	-	(6.95)
Transportation costs	(0.05)	(3.09)	-	(0.55)
Field operating netback	$ 1.36	$ 48.26	$ 16.61	$ 12.93
Realized gain (loss) on commodity price contracts	(0.35)	2.72	-	(1.45)
Field operating netback including hedging	$ 1.01	$ 50.98	$ 16.61	$ 11.48

(1) Production costs of condensate and natural gas liquids are included within natural gas costs.
(2) Realized gains and losses on crude oil contracts are included within the condensate netback.

The fourth quarter field operating netback increased by 9% (27% increase including hedging) compared to the same period in 2016.



General and Administrative Costs

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period – before recoveries	$ 1,879	$ 1,755	$ 7,442	$ 6,520
Overhead recoveries	(335)	(589)	(1,284)	(1,183)
Charge for period – net of recoveries	$ 1,544	$ 1,166	$ 6,158	$ 5,337
Per Boe	$ 0.94	$ 0.95	$ 1.05	$ 1.10

General and administrative costs before recoveries for the three months and year ended December 31, 2017 increased by 7% and 14%, respectively, when compared to the same periods of 2016. The increase in general and administrative costs in 2017 compared to 2016 is primarily attributable to costs incurred relating to the Company's graduation from the TSX Venture Exchange to the TSX in September 2017 as well as higher compensation costs. Overhead recoveries for the periods presented fluctuate in response to the relative magnitude of field capital expenditures.

Net general and administrative costs on a per-Boe measure fell by 5% in 2017 compared to 2016 and by 1% in the fourth quarter of 2017 compared to the fourth quarter of 2016. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Interest and Finance Costs

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 1,105	$ 910	$ 4,007	$ 3,268
Average interest rate(1)	4.4%	4.9%	4.4%	4.6%
Per Boe	$ 0.67	$ 0.74	$ 0.69	$ 0.68

(1) Includes financing and standby fees.

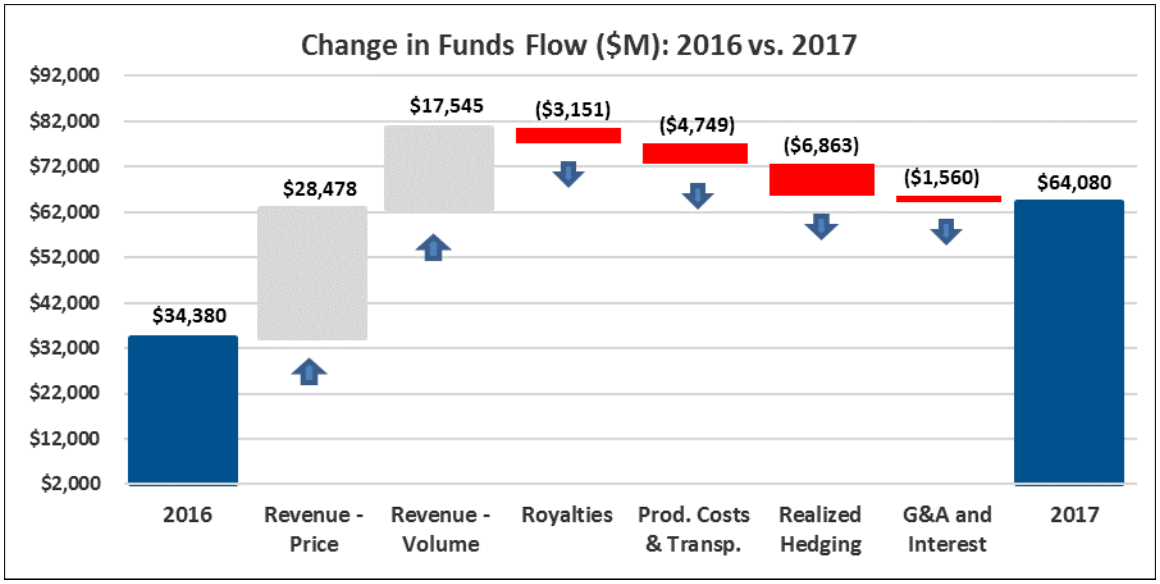
The interest rate on the Company's bank facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Compared to the equivalent periods in the prior year, interest and finance costs in 2017 increased by 23% annually and 21% quarterly, primarily driven by additional bank borrowings used to fund development of the Company's Umbach property which was partially offset by lower average interest rates.

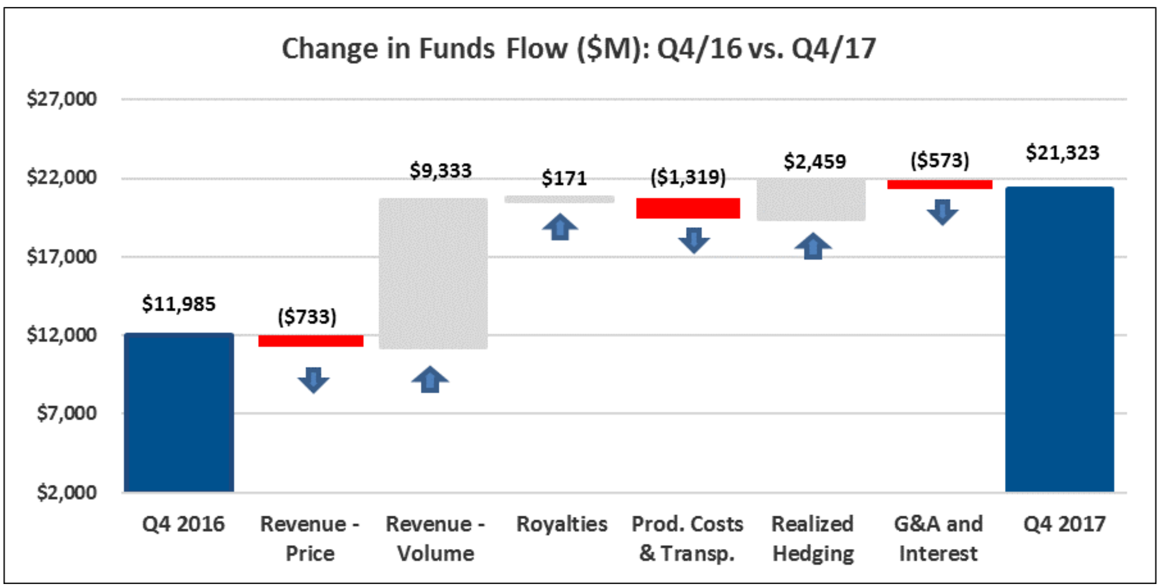
Funds Flow

	Three Months to Dec. 31, 2017		Three Months to Dec. 31, 2016		Year Ended Dec. 31, 2017		Year Ended Dec. 31, 2016	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$21,323	$0.18	$11,985	$0.10	$64,080	$0.53	$34,380	$0.29

Funds flow, a measure that is not defined under IFRS, is cash from operations before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies and is used by lenders to establish interest rates applied to credit facilities.



On an annual basis, production growth and an increase in Storm's realized price were the predominant factors in funds flow growth of 86% in 2017 from 2016.



Funds flow for the fourth quarter of 2017 increased by 78% from 2016. Funds flow benefitted from both production growth and realized hedging gains on commodity price contracts relative to the same period in 2016.

Share-Based Compensation

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 902	$ 808	$ 3,816	$ 3,124
Per Boe	$ 0.55	$ 0.66	$ 0.65	$ 0.65

Share-based compensation is a non-cash charge which reflects the estimated value of stock options issued to Storm's directors, officers and employees. Share-based compensation increased by 22% in 2017 compared to 2016 and by 12% in the fourth quarter of 2017 compared to the same quarter in 2016. The increase in share-based compensation is primarily attributable to a higher option valuation associated with options granted in December 2016.

Depletion and Depreciation

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Depletion	$ 9,285	$ 8,643	$ 38,325	$ 34,450
Depreciation	1,541	1,333	5,904	5,060
Charge for period	$ 10,826	$ 9,976	$ 44,229	$ 39,510
Per Boe	$ 6.56	$ 8.14	$ 7.57	$ 8.17

A 21% increase in production volumes resulted in the total charge for depletion and depreciation increasing by 12% in 2017 compared to 2016. For the three month period, production volumes grew by 35% year over year with the depletion and depreciation charge growing by 9%. The quarterly and year-to-date per-Boe decreases in depletion correspond to lower finding and development costs at Umbach. Increased depreciation charges year over year correspond to increased investment in facilities during 2017.

Exploration and Evaluation Costs Expensed

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 13	$ 41	$ 386	$ 41
Per Boe	$ 0.01	$ 0.03	$ 0.07	$ 0.01

Exploration and evaluation costs expensed in each of the reporting periods above is a non-cash charge representing the write-off of costs associated with undeveloped lands with lease terms expiring in the period.

Accretion

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Charge for period	$ 128	$ 83	$ 454	$ 347
Per Boe	$ 0.08	$ 0.07	$ 0.08	$ 0.07

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The higher charge for accretion in 2017 compared to 2016 is due to obligations incurred in the year and changes in rate estimates over the course of the year, including changes to inflation rates, discount rates and estimated settlement dates. The obligations incurred and changes in the aforementioned rate estimates also resulted in a slightly higher accretion charge in the fourth quarter of 2017 relative to the fourth quarter of 2016.

Reduction of Carrying Amount of Property and Equipment

Each reporting period the Company assesses whether there are indicators of impairment of its property and equipment. If it is determined that indicators do exist, management reviews the recoverable amount of the relevant CGU, the recoverable amount being defined as the greater of its estimated value in use and its fair value less cost to sell. The Company determines the recoverable amount by using a determination of fair value using the sale of a similar asset in an arm's length transaction or by using a discounted future cash flow approach. The assessment of the carrying amount of each of the Company's CGUs is based on estimates of fair value.

Management reviewed the carrying amount of exploration and evaluation assets and property and equipment for indicators of impairment at December 31, 2017. Based on this review, the Company determined there were no indicators of impairment for exploration and evaluation assets as these strategic assets are longer term in nature and less subject to short-term commodity price fluctuations. In regards to property and equipment, there were no indicators of impairment as the Company's Umbach property remains resilient at low commodity prices, with continued outperformance of this asset in terms of reserve growth at increasingly lower finding and development costs.

The imprecision of estimates of future revenue streams should be recognized and the reduction of the carrying amount of any CGU is not an attempt to put a market value on any of the Company's properties.

Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been recognized in respect of potential future income tax reductions resulting from the use of accumulated tax losses. Details of Storm's tax pools are as follows:

Tax Pools	As at December 31, 2017	Maximum Annual Deduction
Canadian oil and gas property expense	$ 48,000	10%
Canadian development expense	125,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	78,000	20% – 100%
Operating losses	204,000	100%
Other	1,000	20% – 100%
Total	$ 479,000	

Net Income (Loss)

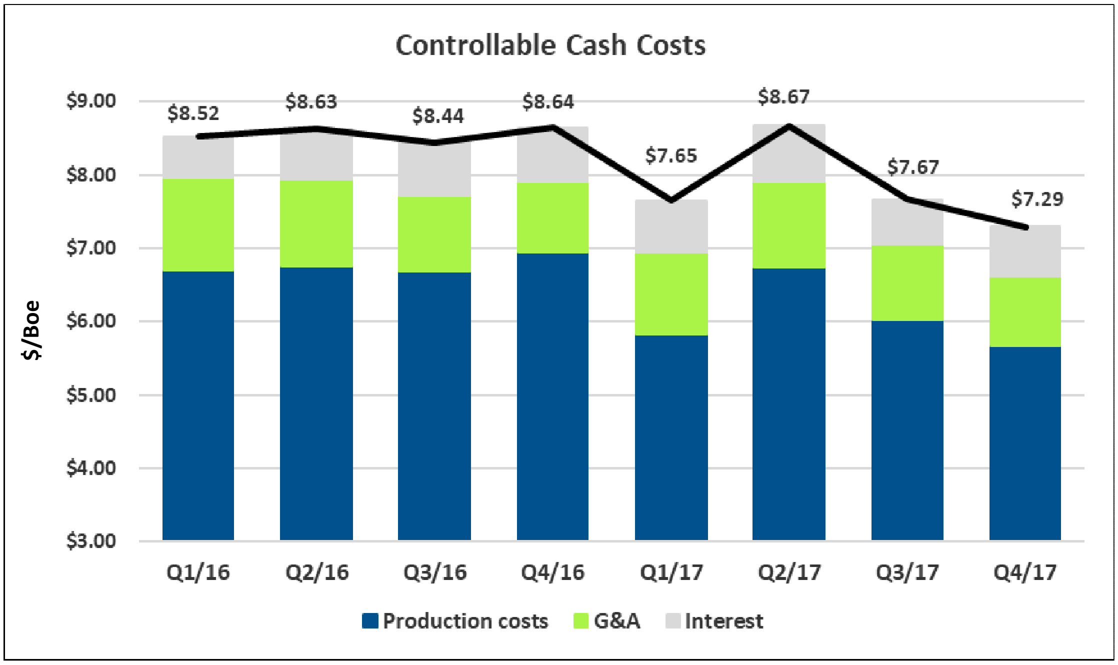
	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Net income (loss)	$ 8,624	$ (12,898)	$ 39,689	$ (38,460)
Per basic and diluted share	$ 0.07	$ (0.11)	$ 0.33	$ (0.32)

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion on reported net income for both the year and three months ended December 31, 2017 relative to the same periods in 2016. For 2017, the unrealized gain on commodity price contracts included in the measurement of net income amounted to $24.6 million compared to the unrealized loss in 2016 of $30.1 million. Similarly, for the fourth quarter of 2017 an unrealized loss on commodity price contracts of $0.8 million was recorded compared to an unrealized loss for the same period in 2016 of $13.9 million.

The increase in year-over-year and quarter-over-quarter net income, excluding unrealized gains and losses on commodity price contracts, compared to the same periods in 2016 is primarily attributed to increased production and higher per-Boe revenue.

Corporate Netbacks

($/Boe)	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Revenue from product sales	21.12	21.42	21.09	15.97
Realized gain (loss) on commodity price contracts	0.41	(1.45)	(0.40)	0.93
Royalties	(0.63)	(0.99)	(1.19)	(0.79)
Production	(5.68)	(6.95)	(6.04)	(6.78)
Transportation	(0.69)	(0.55)	(0.76)	(0.45)
General and administrative	(0.94)	(0.95)	(1.05)	(1.10)
Interest and finance costs	(0.67)	(0.74)	(0.69)	(0.68)
Funds flow	12.92	9.79	10.96	7.10
Share-based compensation	(0.55)	(0.66)	(0.65)	(0.65)
Depletion, depreciation and accretion	(6.64)	(8.21)	(7.65)	(8.24)
Exploration and evaluation costs expensed	(0.01)	(0.03)	(0.07)	(0.01)
Unrealized revaluation loss on investments	(0.01)	(0.04)	(0.02)	(0.02)
Gain on sale of oil and gas properties	-	-	-	0.09
Unrealized gain (loss) on commodity price contracts	(0.49)	(11.36)	4.21	(6.23)
Net income (loss)	5.22	(10.51)	6.78	(7.96)



Controllable cash costs per Boe, including production costs, general and administrative costs and interest and finance costs, decreased 16% to $7.29 in the fourth quarter of 2017 compared to $8.64 for the fourth quarter of 2016, and decreased 9% to $7.78 for 2017 compared to $8.56 for 2016. Transportation costs are excluded as the sales price on a portion of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago. Comparing the respective annual and quarterly results above, all components of controllable cash costs decreased, with the exception of interest costs which have increased marginally in 2017 due to higher bank borrowings. Lower natural gas processing fees commencing January 1, 2017 are the primary contributor to reductions in cash costs per commodity unit.

INVESTMENT AND FINANCING

Financial Resources and Liquidity

On April 25, 2017, the Company's credit facility was increased to $165 million from $130 million in recognition of production and reserve growth at Umbach. The credit facility is available until April 27, 2018 at which time the borrowing base amount will be reviewed using independently evaluated reserve information. In the ordinary course of business, the Company has the option to extend the credit facility for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The credit facility is syndicated with three banks.

At December 31, 2017, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the credit facility limit. At December 31, 2017, debt including working capital deficiency amounted to $106.1 million, representing 64% of the available credit facility.

In quarters of high field activity, Storm operates with a working capital deficit, which will be reduced in quarters of lower field activity. The Company's capital expenditure budget is set by management at the beginning of the calendar year and approved by the Board of Directors. It is updated regularly with changes subject to approval by the Board of Directors. Management is accountable to the Board of Directors for the execution of the business plan represented by the budget and updates the Board on progress at least four times a year.

Capital Expenditures

In the fourth quarter of 2017, the Company spent $26.1 million (2016 - $33.4 million) on field operations, primarily on drilling seven wells and completing three wells at Umbach.

During 2017, the Company spent $81.7 million (2016 - $65.5 million) on field operations, drilling 16 horizontal wells, completing 12 horizontal wells and bringing 13 horizontal wells on production (all 100% working interest wells).

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Land and seismic	$ 765	$ 240	$ 1,844	$ 1,413
Drilling	13,329	11,000	31,329	22,419
Completions	8,055	8,771	28,537	18,465
Facilities	858	11,576	6,352	18,838
Equipping and pipelines	2,943	1,776	12,175	4,218
Recompletions and workovers	172	7	1,434	141
Property acquisition and administrative assets	4	29	14	44
Total capital expenditures	$ 26,126	$ 33,399	$ 81,685	$ 65,538
Proceeds on disposition of oil and gas properties	-	-	-	(600)
Net capital expenditures	$ 26,126	$ 33,399	$ 81,685	$ 64,938

Net capital investment was allocated as follows:

	Three Months to Dec. 31, 2017	Three Months to Dec. 31, 2016	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Exploration and evaluation	$ 765	$ 240	$ 1,838	$ 921
Property and equipment	25,361	33,159	79,847	64,017
Total capital expenditures, net of dispositions	$ 26,126	$ 33,399	$ 81,685	$ 64,938

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at December 31, 2017 corresponds to the active field program at Umbach.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at December 31, 2017 was $36.3 million (December 31, 2016 - $28.3 million) and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, and (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value was 2.2% (December 31, 2016 – 2.2%). Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources and with reference to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to December 31, 2017 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds[1] ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended Dec.31/14	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended Dec.31/15	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Year ended Dec.31/16	Stock option exercises	1,297	$ 1.97	2,558
Year ended Dec.31/17	Stock option exercises	793	$ 1.83	1,456
Total at December 31, 2017		121,557	$ 3.26	$ 395,930

(1) Before share issue costs and transfers from contributed surplus.

During 2016, stock options were exercised at an average price of $1.97 per optioned share and 1,297,000 common shares were issued for proceeds of $2,558,000. During 2017, stock options were exercised at an average price of $1.83 per optioned share and 793,000 common shares were issued for proceeds of $1,456,000.

Issued and outstanding common shares at December 31, 2017 and at March 1, 2018, the date of this MD&A, totaled 121,556,812.

CONTRACTUAL OBLIGATIONS

In the course of its business, Storm enters into various contractual obligations, including the following:

- purchase of services;
- royalty agreements;
- operating agreements;
- processing and transportation agreements;
- right of way agreements;
- lease obligations for accommodation, office equipment and automotive equipment;
- banking agreements; and
- commodity price contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At December 31, 2017 the remaining office lease commitment is $0.7 million. Subsequent to December 31, 2017, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years. In addition, as at the date of this report, the Company has natural gas transportation and processing commitments valued at a total of approximately $401.5 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended December 31, 2017 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results for the first half of 2016 reflect the relentless fall in commodity prices in the period resulting in a reduction to capital investment and a flat production profile. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to implement a larger capital expenditure program in the fourth quarter of 2016 which increased production in the first quarter of 2017 as new wells were turned on.

The second and third quarters of 2017 saw a retreat in pricing for natural gas and condensate and a decrease in volumes due to a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow. With road bans in place for the better part of the second quarter of 2017, capital expenditures were limited as no wells were drilled or completed during the quarter. As road bans were lifted, the third quarter saw a return to normal field activity levels with three wells drilled and five wells completed. However, low natural gas prices in the third quarter of 2017 resulted in production being managed to the level required to meet firm processing and transportation commitments.

Despite a decrease of 37% in Station 2 pricing in the fourth quarter of 2017 compared to the preceding quarter, Storm's realized price increased 23% to $21.12 per Boe, primarily due to an increase in liquids pricing. Production volumes increased 18% compared to the preceding quarter, which contributed to higher revenue and funds flow in the fourth quarter of 2017.

				2017				2016
($000s unless otherwise stated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue from product sales	34,844	24,100	27,317	37,045	26,244	21,047	13,870	16,121
Funds flow	21,323	13,170	11,629	17,958	11,985	8,759	5,781	7,855
Per share – basic and diluted ($)	0.18	0.11	0.10	0.15	0.10	0.07	0.05	0.07
Net income (loss)	8,624	682	9,752	20,631	(12,898)	(85)	(20,493)	(4,984)
Per share – basic and diluted ($)	0.07	0.01	0.08	0.17	(0.11)	(0.00)	(0.17)	(0.04)
Net capital expenditures	26,126	23,895	4,307	27,357	33,399	6,980	613	23,946
Average daily production (Boe)	17,936	15,193	13,991	16,947	13,320	13,285	12,852	13,418
Debt including working capital deficiency(1)	106,124	101,297	90,582	97,864	89,841	69,303	71,254	77,162

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.

SELECTED ANNUAL FINANCIAL INFORMATION

($000s unless otherwise stated)	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Revenue from product sales	123,306	77,283	67,736
Funds flow	64,080	34,380	39,046
Per share – basic and diluted ($)	0.53	0.29	0.34
Net income (loss)	39,689	(38,460)	(6,867)
Per share – basic and diluted ($)	0.33	(0.32)	(0.06)
Total assets	515,563	465,617	440,658
Debt including working capital deficiency[(1)]	106,124	89,841	61,721
Average daily production (Boe)	16,017	13,219	9,956
Funds flow ($/Boe)	10.96	7.10	10.76

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.

The trend in annual results follows a similar story line to that of the quarterly results. Strong production growth over the last three years has been overshadowed by volatile commodity prices. This is evidenced by the downward trend in funds flow from 2015 to 2016 due to a prolonged period of low commodity prices, a trend that was reversed in 2017. Net income (loss) has also been negatively affected by low commodity prices, although it is subject to a great degree of variability due to unrealized gains and losses on commodity price contracts. The Company reported a $24.6 million unrealized gain on commodity price contracts for the year ended December 31, 2017, an unrealized loss on commodity price contracts of $30.1 million for the year ended December 31, 2016 and an unrealized loss on commodity price contracts of $4.9 million for the year ended December 31, 2015.

The increase in the Company's total assets reflects the ongoing development of the Company's Montney play at Umbach. Debt including working capital deficiency has increased over the last three years reflecting capital expenditures exceeding funds flow. While the increase in 2017 capital expenditures was largely directed to drilling and completions, a significant driver of capital expenditures in 2016 was the decision to accelerate construction of a third field compression facility in the second half of the year, adding expenditures of $18.8 million in 2016. This investment increased Storm's compression capacity by more than one-third, and resulted in a considerable increase in production in 2017.

Share Trading

Set out below is share trading activity for Storm for 2017 and 2016.

					2017					2016
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	5.33	4.64	4.17	3.76	5.33	3.97	4.45	5.20	5.66	5.66
Low ($)	3.60	3.60	3.25	2.41	2.41	2.91	3.22	3.71	4.44	3.00
Close ($)	4.15	4.20	3.54	2.70	2.70	3.46	4.05	4.85	5.30	5.30
Volume traded (000s)	6,461	6,576	3,539	5,030	21,606	13,227	7,008	10,421	12,924	43,581
Value traded ($000s)	27,831	23,342	12,941	14,931	82,045	44,759	26,293	44,807	66,177	182,036
Weighted average trading price ($)	4.31	4.01	3.66	2.97	3.80	3.38	3.75	4.30	5.12	4.18

Note: Data obtained from the TMX website.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the audited consolidated financial statements for the years ended December 31, 2017 and 2016 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary; further, it may change between reporting periods. Variations between amounts estimated and actual results could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

Estimates of quantities of proven and probable reserves of natural gas and NGL (which includes condensate) are not a financial measurement. However, estimated future cash flows associated with reserves are used in impairment assessments for exploration and evaluation assets and property and equipment, the measurement of decommissioning obligations and depletion and depreciation of property and equipment. Such estimates of cash flows involve assumptions regarding future commodity prices, exchange rates, discount rates, inflation rates and future production and transportation costs and, of necessity, involve uncertainty. Reserve estimates are prepared annually by independent qualified reserve evaluators in accordance with independently established industry standards using, in part, data supplied by the Company. The results of the independent reserve evaluation are reviewed by the Reserves Committee of the Company's Board of Directors. In certain circumstances the Company will prepare internal estimates of reserves which may be used in accounting measurements applicable to interim reporting periods.

Accounts Receivable, Accounts Payable and Accrued Liabilities

At the end of each reporting period the Company estimates the amount receivable from product sales and from joint venture partners to the extent that these amounts are not determinable from purchaser statements or amounts invoiced to partners. In addition, the Company estimates the cost of services and materials provided by suppliers during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes such revenues and costs using well established measurement procedures. Nonetheless, such procedures reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced, either to or by the Company, relate in large part to the Company's capital expenditure programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts receivable, accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity the amount subject to estimation may be a large part of the total amount.

Commodity Price Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty. Crude oil contracts are used as a proxy for condensate and NGL contracts, as part of the Company's condensate and NGL stream is priced with reference to crude oil index prices.

Exploration and Evaluation Assets

Costs incurred by the Company in the assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences or reserves are assigned, or are expensed if management determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. The amounts transferred to property and equipment, or expensed, and the timing of the decisions relative to each, are subject to measurement uncertainty. Furthermore, the carrying amount of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods. The carrying amount of exploration and evaluation assets is reviewed at the end of each reporting period for indicators of impairment. If such indicators exist the carrying amount will be measured against the estimated recoverable amount and, if necessary, reduced. This review involves estimates and judgments by management and thus involves a high degree of uncertainty.

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management, and the estimates used could differ from similar estimates developed by other parties. In addition, acquired property and equipment is initially recorded at fair value as determined by management. Measurement of fair value includes estimation and judgment and is inherently subjective and uncertain.

Property and equipment is subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made.

The carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount; as a result adjustments to the carrying amount may be made. All of these involve assumptions regarding uncertain future events and circumstances.

Decommissioning Liability

Storm records as a liability the discounted estimated fair value of obligations associated with the decommissioning of field assets. The carrying amount of exploration and evaluation assets and property and equipment is increased by an amount equivalent to the liability. In summary, the decommissioning liability reflects the present value of estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of incurrence of these costs. The liability is increased each reporting period to reflect the passage of time, with the charge for accretion included in earnings. The liability is also adjusted to reflect changes in the amount and timing of future retirement obligations as well as asset dispositions and is reduced by the amount of any costs incurred in the period. Adjustments are also made to the liability in response to changes in discount and inflation rates. The amount of future decommissioning costs, the timing of incurrence of such costs, the discount rate and, correspondingly, the charge for accretion, are subject to uncertainty of estimation. In addition, the decommissioning activities to which the estimates relate are likely to take place many years, potentially decades, in the future. The long timeline between incurrence and eventual satisfaction of the obligation will inevitably affect the accuracy of the estimation process.

Share-Based Compensation

To determine the charge for share-based compensation, the Company estimates the fair value of stock options at the time of issue using assumptions regarding the life of the option, dividend yields, interest rates and the volatility of the security under option. Although the assumptions used to value a specific option remain unchanged throughout the life of the option, assumptions may change with respect to subsequent option grants. In addition, the assumptions used may not properly represent the fair value of stock options at any time; as no alternative valuation model is applied, the difference between the Company's estimation of fair value and the actual value of the option is not measurable. Although the methodology used to measure the charge for share-based compensation is largely uniform across Storm's peers, inputs to the calculation, and thus the charge, may vary considerably.

Income Taxes

The measurement of Storm's tax pools, losses and deferred tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings and compliance with tax regulations are subject to audit and reassessment, potentially several years after the initial filing. In addition, the amount and timing of use of tax pools may be affected by future legislation. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's March 1, 2018 press release, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold including prices as outlined in 2018 guidance;
- future average production volumes in the fourth quarter of 2018 and annual production for 2018, production growth of a minimum of 25% in 2018, along with production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2018 guidance;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2018 capital expenditure program including 2018 maintenance capital of $55 million to $60 million and 2019 maintenance capital of $35 million to $40 million;
- first quarter of 2018 production and capital investment of 19,500 to 20,500 Boe per day and $23 million, respectively, along with capital investment being less than funds flow for the first half of 2018 leading to debt reduction of $10 million to $15 million;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including the amounts outlined in 2018 guidance and per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities including $57 million of unused credit capacity at year end;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells including improvements on future wells from drilling longer wells leading to outperformance of the 7.5 Bcf type curve;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2018 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and natural gas liquids, specifically the anticipated sales percentage allocation in 2018 to Chicago, Sumas, Station 2 and AECO markets;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

Statements relating to "reserves" or "resources" including related financial measurements, such as net present value, are forward-looking statements, as they imply, based on estimates and assumptions, including assumptions regarding future prices, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include the material uncertainties and risks described or incorporated by reference in this MD&A under “Critical Accounting Estimates”; “Business Risks”; “Financial Reporting Update”; and the material assumptions and observations described under the headings “Overview”; “Production and Revenue”; “Commodity Price Risk Management”; “Royalties”; “Production Costs”; “Transportation Costs”; “Field Operating Netbacks”; “General and Administrative Costs”; “Interest and Finance Costs”; “Funds Flow”; “Share-Based Compensation”; “Depletion and Depreciation”; “Exploration and Evaluation Costs Expensed”; “Accretion”; “Reduction of Carrying Amount of Property and Equipment”; “Income Taxes”; “Net Income (Loss)”; “Financial Resources and Liquidity”; “Capital Expenditures”; “Accounts Payable and Accrued Liabilities”; “Decommissioning Liability”; “Share Capital”; “Contractual Obligations”; industry conditions including commodity prices, facility and pipeline capacity constraints and access to processing facilities and to market for production; currency fluctuations; imprecision of reserve estimates and related costs including future royalties, production and transportation costs and future development costs; environmental risks; competition from other industry participants; the lack of availability of qualified personnel or management; stock market volatility; ability to access sufficient capital from internal and external sources; and the ability of the Company to realize value from its properties. All of these caveats should be considered in the context of current economic conditions, in particular low, in a historical context, prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing domestic and international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company’s business. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm’s actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

Boe Presentation - Natural gas is converted to a barrel of oil equivalent (“Boe”) using six thousand cubic feet (“Mcf”) of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel (“Bbl”) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of natural gas to one barrel of oil.

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles (“GAAP”). Specifically, “debt including working capital deficiency”, “field operating netbacks”, “field operating netbacks including hedging”, and measurements “per commodity unit” and “per Boe” do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. Non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, lenders, analysts and other parties.

Field operating netbacks and field operating netbacks including hedging are common non-GAAP measurements applied in the oil and gas industry and are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting royalties, production and transportation expenses from revenue from product sales and are presented on a per-Boe basis.

Controllable cash costs per Boe, including production costs, general and administrative costs and interest and finance costs, are used by management to assess financial and operational performance.

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of commodity price contracts. Management believes this is a key measure to assess the Company’s liquidity and is used by the Company’s lenders to set corporate interest rates.

BUSINESS RISKS

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. The following reviews a number of the identifiable business risks faced by the Company. Business risks evolve constantly and additional risks emerge periodically. The risks below are those identified by management at the date of completion of this report, and may not describe all of the material business risks, identifiable or otherwise, faced by the Company.

Property Exploitation

Storm's exploitation programs require sophisticated and scarce technical skills as well as capital and access to land and oilfield service equipment. Storm endeavours to minimize the associated risks by ensuring that:

- Activity is focused in core regions where internal expertise and experience can be applied;
- Prospects are internally generated;
- Development drilling is in areas where there is immediate or near-term access to facilities, pipelines and markets or where construction of necessary infrastructure is within the Company's financial capacity;
- The Company seeks to act as operator and to maintain a 100% or high working interest. The Company can thus control the timing, cost and technical content of its exploration and development programs.

Nevertheless, drilling and completing a well may not result in the discovery of economic reserves, or a well may be rendered uneconomic by commodity price declines or an increasing cost structure.

In addition, the Company's investment program is currently focused on the development of the Umbach property, resulting in asset concentration risk.

Commodity Price Fluctuations

When the Company identifies hydrocarbons of sufficient quantity and quality and successfully brings them on stream, it faces a pricing environment which is volatile and subject to a myriad of factors, largely out of the Company's control. Low prices for the Company's expected primary products will have a material effect on the Company's funds flow and profitability and thus re-investment capacity, and hence ultimate growth potential. Low prices also limit access to capital, both equity and debt. The Company in part mitigates the risk of pricing volatility through the use of commodity price contracts, such as fixed priced sales, swaps, collars and similar contracts. However, access to such commodity price protection instruments may not be available in future periods, or available only at a cost considered to be uneconomic. Such commodity price contracts tend to be for short periods and the pricing protection this provides has limited effect against medium and long term pricing trends. The Company may shut in production rather than sell it at prices considered by management to be unacceptably low. The Company's production base is almost entirely natural gas and associated liquids, a trend unlikely to change in future years, resulting in commodity concentration risk.

Adverse Well or Reservoir Performance

Changes in productivity in wells and areas developed by the Company could result in termination or limitation of production, or acceleration of decline rates, resulting in reduced overall corporate volumes and revenues. In addition, wells drilled by the Company tend to produce at high initial rates followed by rapid declines until a flattening decline profile emerges. There is a risk that the decline profile which eventually emerges for newly drilled wells is sub-economic. In addition, the Company's property at Umbach is in the early stage of development and there is a risk that unforeseeable circumstances may emerge which will adversely affect reservoir performance.

Field Operations

Storm's current and future exploration, development and production activities involve the use of heavy equipment and the handling of volatile liquids and gases. Catastrophic events, regardless of cause or responsibility, such as well blowouts, explosions and fires within pipeline, gathering, or facility infrastructure, as well as failure of gathering systems or mechanical equipment, could lead to releases of liquids or gases, spills of contaminants, personal injuries and death, damage to the environment, as well as uncontrolled cost escalation. With support from suitably qualified external parties, the Company has developed and implemented policies and procedures to mitigate environmental, health and safety risks. These policies and procedures include the use of formal corporate policies, emergency response plans, and other policies and procedures reflecting what management considers to be best oil field practices. These policies and procedures are subject to periodic review. Storm also manages environmental and safety risks by maintaining its operations to a high standard and complying with all provincial and federal environmental and safety regulations. Nevertheless, application of best practices to field operations serves only to mitigate, not eliminate, risk.

The Company's areas of activity are relatively undeveloped. In any new area of activity, property access and production require considerable early stage investment, for example, road construction, access to processing facilities, pipelines and other transportation arrangements, which is not necessarily applicable to more mature producing areas. In addition, supervision and maintenance of production facilities is likely to be more expensive than in existing and more accessible producing areas. In addition, the Company's property at HRB in northeast British Columbia, is in an area which is climatically and geographically hostile.

Storm maintains industry-specific insurance policies, including environmental damage and business interruption, on important owned and non-owned production and processing facilities. Although the Company believes its current insurance coverage corresponds to industry standards, there is no guarantee that such coverage will be available in the future, and if it is, at a cost acceptable to the Company, or that existing coverage will necessarily extend to all circumstances or incidents resulting in loss or liability.

Retention of Key Personnel

A loss in key personnel of Storm could delay the completion of certain projects or otherwise have a material adverse effect on the Company. Shareholders are dependent on Storm's management and staff in respect of the administration and management of all matters relating to the Company's assets.

Environmental

The Company's operations are subject to extensive environmental regulations which are addressed through formal policies and procedures and application of best field practices. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change initiatives ultimately put in place. Given the evolving nature of climate change discussions, the regulation of emissions of greenhouse gases ("GHG") and potential federal and provincial GHG commitments, the Company is unable to predict the effect on its operations and financial condition at this time. It is possible that the Company could face increases in operating and capital costs in order to comply with increased GHG emissions legislation.

The Company's development program at Umbach involves horizontal drilling and fracturing applications. Fracturing involves the use of large quantities of liquids and chemicals, whose use and subsequent disposal has resulted in the emergence of environmental concerns, primarily in more heavily populated areas elsewhere in North America. In particular, natural gas produced by the Company at Umbach contains hydrogen sulfide, which is potentially lethal and has to be removed from the gas stream. This requires access to specialized processing facilities. Although the Company considers that access to such facilities is adequate for current and near-term production levels, this may not be the case in the future. In addition, future exploitation of shale gas in the HRB may cause management of carbon dioxide volumes produced concurrently with natural gas to become an operational issue.

The evolution of environmental regulation, in particular as it relates to fracturing applications, cannot be predicted at this stage. Nevertheless it is reasonable to expect that management of environmental issues and related societal expectations will become an increasingly important part of the Company's business, with a corresponding effect on costs and economic returns.

Since the majority of the Company's operations are located British Columbia, the Company is subject to the British Columbia Carbon Tax Act, which sets a carbon price of $30 per tonne. Beginning on April 1, 2018, the provincial carbon tax is expected to increase by $5 per tonne, reaching the federal target carbon price of $50 per tonne on April 1, 2021.

In addition to Company-specific environmental concerns, increasing public and political focus on climate change and its possible amelioration, may cause changes in demand for the Company's products and the introduction of regulations which may result in changes to the Company's operating practices as well as additional and unforeseeable costs and the incurrence of future liabilities, real or contingent. Changes in public policy in response to changes in government at federal and provincial levels over the next several years cannot be determined at this stage, but given that the Company is a producer of primary hydrocarbons it is likely that its business will be subject to increased regulation and potentially subject to additional taxes, costs and obligations.

Industry Capacity Constraints

The collapse in prices for crude oil and natural gas, in a historical context, has reduced field activity and thus concerns over access to equipment and services. Further, service costs have fallen in recent years and remain relatively stable. Nevertheless, periods of high field activity can result in shortages of services, products, equipment, or manpower in many or all of the components of the development cycle. Increased demand leads to higher land and service costs during peak activity periods. In addition, access to transportation and processing facilities may be difficult or expensive to secure. Storm's competitors include companies with far greater resources, including access to capital and the ability to secure oilfield services at more favourable prices and to build out operations on a scale which lowers the economic threshold for exploitation of a resource. Storm competes by maintaining a large inventory of self-generated exploration and development locations, by acting as operator where possible, and through facility access and ownership. Storm also seeks to carefully manage key supplier relationships. Declines in commodity prices should, in principle, result in lower service costs; however, this may be offset by service providers choosing to retire equipment rather than operate at sub-optimum prices, or ceasing business altogether.

Capital Programs

Capital expenditures are designed to accomplish two main objectives, being the generation of short and medium term cash flow from development activities, and expansion of future cash flow from the identification of or further development of reserves. The Company focuses its activity in core areas, which allows it to leverage its experience and knowledge, and acts as operator wherever possible. The Company may use farm-outs to minimize risk on plays it considers higher risk or where total capital invested exceeds an acceptable level. In addition, Storm may enter into commodity price contracts in support of capital programs, and to manage future debt levels. Generally, capital programs are financed from cash flow and disciplined use of debt, and occasionally, equity. Failure to develop producing wells or to sell production at a reasonable price and thus maintain an acceptable level of cash flow, will result in the exhaustion of available financial resources and will require the Company to seek additional capital which may not be available, or only available on unacceptable terms, or terms highly dilutive to existing shareholders. In addition, credit availability from the Company's bankers is also necessary to support capital programs and any changes to credit arrangements may have an effect on both the size of the Company's future capital programs and the timing of expenditures. As the banking facility available to the Company is based on future cash flows from existing production, falling commodity prices will likely have an effect on borrowing availability.

Reserve Estimates

Estimates of economically recoverable oil and natural gas reserves and natural gas liquids, and related future net cash flows, are based upon a number of variable factors and assumptions. These include commodity prices, production, future operating, transportation, development and facility as well as decommissioning costs, access to market, and potential changes to the Company's operations or to reserve measurement protocols arising from regulatory or fiscal changes. All of these estimates may vary from actual circumstances, with the result that estimates of recoverable oil and natural gas reserves attributable to any property are subject to revision. In future, the Company's actual production, revenues, royalties, transportation, operating expenditures, finding, development, facility and decommissioning costs associated with its reserves may vary from such estimates, and such variances may be material.

Production

Production of oil and natural gas reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Company will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Company to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating field activity in regions where infrastructure is or will be Storm owned, or readily accessible at an acceptable cost. In periods of low commodity prices the Company will shut in production, either temporarily or permanently, if netbacks are sub-economic.

Production is also dependent in part on access to third party facilities and pipelines with the result that production may be reduced by outages, accidents, maintenance programs and similar interruptions outside of the Company's control. For example, a gas processing facility, to which a majority of the Company's gas production is directed, was closed for maintenance in the second and third quarters of 2017 for a period of 39 days. Generally, this facility is closed for significant maintenance every three years.

Storm's contracted gas processing capacity at third party facilities was approximately 80% of total raw gas production during December 2017 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in if capacity available to Storm is allocated to other parties. Transportation of gas to processing facilities and to market is similarly exposed to the extent that the required capacity is not covered by contract. In addition, contracts for processing or pipeline access are for a fixed term and may not be renewed or may be renewed under more onerous terms.

Financial and Liquidity Risks

The Company faces a number of financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies. The Company uses the guidelines below to address financial exposure. Although these guidelines result in conservative management of the Company's finances, they cannot eliminate the financial risks the Company faces.

- Internal funds flow provides the initial source of funding on which the Company's capital expenditure program is based.
- Debt, if available, may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled. The Company measures debt levels against current or near-term funds flow. If the debt-to-cash-flow ratio becomes unacceptably high, capital programs will be postponed, assets sold or farmed out or other measures taken to bring debt levels down.
- Interest rate contracts, if available, may be used to manage fluctuations in interest rate.
- Equity, if available on acceptable terms, may be raised to fund acquisitions and capital programs.
- Farm-outs of projects may be arranged if management considers that the capital requirements of a project are excessive in the context of the Company's resources, or where the project affects the Company's risk profile, or where the project is of lower priority.
- Commodity price contracts, if available, may be used to manage commodity price volatility when the Company has capital programs, including acquisitions, whose cost exceeds near-term projected funds flow and where capital programs involve longer term commitments.
- The Company will also sell assets at an acceptable price if the proceeds can be redeployed in properties offering a higher netback or greater development potential.

Marketing Risks

Markets for future production of crude oil and natural gas are outside the Company's capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, as well as downtime due to maintenance or damage, either to owned or third party facilities and pipelines. The Company will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to processing and pipeline or other transportation infrastructure, and, where possible, owned by the Company.
- The Company will delay drilling or tie-in of new wells or shut in production if acceptable pricing cannot be realized.
- The Company constantly assesses the various markets into which production can be sold and if possible will direct production to markets offering the most attractive returns.
- The Company endeavours to secure access to facilities and pipelines under contracts setting volumes, prices and term.

Storm has contracted pipeline transportation capacity for approximately 76 Mmcf per day of natural gas sales volumes in the first quarter of 2018 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in during partial outages or if capacity is allocated to other parties.

The Company's product profile comprises a large and growing percentage of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in North America. When, if ever, access to historical markets in North America may improve, is not predictable. Further, development of certain natural gas reserves in Canada is to a degree underwritten by the expectation that new Pacific Rim export markets will be accessed through the establishment of LNG liquefaction facilities on Canada's west coast. When such facilities will be completed, if ever, cannot be predicted.

Access to Debt and Equity

The Company's funds flow and borrowing capacity is sufficient to fund its existing capital budget. Nevertheless, funding is finite and investment must result in production being brought on stream, followed by the generation of funds flow and the identification of proved and probable reserves. Bank financing, which for junior oil and gas companies like Storm, is conventionally a loan, renewable annually but subject to semi-annual review, is based on anticipated future funds flows. Thus, bank financing is short term only and availability is likely to be reduced in response to lower production or lower commodity prices. Banking arrangements are renewed in April each year and are subject to mid-year review.

Although equity is another source of financing, the Company is exposed to changes in the equity markets, which could result in equity not being available, or only available under conditions which are unacceptably dilutive to existing shareholders. The inability of the Company to develop profitable operations, with the consequent exclusion from debt and equity markets, may result in the Company curtailing or suspending operations.

Changes in Government Regulations, Royalties and Policies

In both Canada and the United States the energy industry is subject to scrutiny, frequently hostile, by political and environmental groups. This may lead to increased regulation and increased compliance costs. In particular, there is a risk that existing royalty incentive programs could be terminated or amended, royalty or income tax rates could be increased, rules and regulations around well licensing or surface access could be changed, horizontal drilling and hydraulic fracturing could be subject to increased oversight or regulation, First Nations consultation requirements may be changed and GHG emissions targets may be changed which could affect carbon taxes. Further, the renegotiation of the North American Free Trade Agreement initiated by the United States, a primary market for the Company's products, has created uncertainty with regard to market access, commodity prices, exchange rates and other factors, each of which may have an effect on the Company's ability to profitably grow its production.

Cyber-Security

The Company is dependent on information technology, such as computer hardware and software systems, in order to properly operate its business. These systems have the potential for information security risks, which could include potential breakdown, virus, invasion, cyber-attack, cyber-fraud, security breach and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems could result in interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse effect on the protection of intellectual property and confidential and proprietary information, and on the Company's business, financial condition, results of operations and fund flow.

Extraordinary Circumstances

Storm's operations and its financial condition may be affected by uncontrollable, unpredictable and unforeseeable circumstances such as weather patterns, changes in contractual, regulatory or fiscal terms, actions by governments at various levels, both domestic and other, termination of access to third party pipelines or facilities, actions by industry organizations, local communities, militant groups, exclusion from certain markets or other undeterminable events.

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

There were no material new or amended accounting standards adopted during the year ended December 31, 2017.

Future Accounting Policy Changes

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts*. The standard is required to be adopted either retrospectively or using the modified transition approach for fiscal years beginning on or after January 1, 2018, with early adoption permitted. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company intends to retroactively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers and has concluded that the adoption of the new standard will result in presentation changes in revenue and transportation, which will not affect net income or loss or funds flow. In addition, Storm will expand the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type.

In July 2014, the IASB issued IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected loss" impairment method and a substantially reformed approach to hedge accounting. Currently, the Company does not apply hedge accounting to its commodity price contracts nor does it intend to with adoption of IFRS 9. This standard is effective for annual periods beginning on or after January 1, 2018. The Company's financial assets primarily consist of accounts receivable and derivative commodity price contracts. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. The adoption of IFRS 9 will be applied on a retrospective basis on January 1, 2018 and will not have a significant effect on the valuation of the Company's financial assets.

In January 2016 the IASB issued IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for most leases. This standard replaces IAS 17 *Leases* and will be effective for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if IFRS 15 *Revenue from Contracts with Customers* is also adopted. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a "right-to-use asset" for essentially all lease contracts. The Company is currently identifying and analyzing contracts affected by the adoption of IFRS 16. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of this new standard will have a significant effect on the Company's financial statements.

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures ("DCP") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures and have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2017.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting and concluded that the Company's internal controls over financial reporting are effective as of December 31, 2017. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

ADDITIONAL INFORMATION

Additional information relating to the Company can be viewed at www.sedar.com or on the Company's website at www.stormresourcesltd.com. Information can also be obtained by contacting the Company at Storm Resources Ltd., Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4.

FINANCIALS

MANAGEMENT'S REPORT

To the Shareholders of Storm Resources Ltd.

The financial statements of Storm Resources Ltd. were prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Management has used estimates and careful judgment, particularly in those circumstances where transactions affecting current periods are dependent on information not known for certain until a future period. The financial and operational information contained in this year-end report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

March 1, 2018

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Storm Resources Ltd.

We have audited the accompanying consolidated financial statements of Storm Resources Ltd., which comprise the consolidated statements of financial position as at December 31, 2017 and 2016, and the consolidated statements of income (loss) and comprehensive income (loss), cash flows and changes in shareholders' equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Storm Resources Ltd. as at December 31, 2017 and 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 1, 2018

Consolidated Statements of Financial Position

(Canadian $000s)	December 31, 2017	December 31, 2016
ASSETS		
Current		
Accounts receivable (Note 14)	$ 15,104	$ 13,199
Prepaids and deposits	4,542	1,176
Fair value of commodity price contracts (Note 14)	2,842	483
	22,488	14,858
Fair value of commodity price contracts (Note 14)	209	-
Exploration and evaluation (Note 6)	103,907	110,395
Property and equipment (Note 7)	388,959	340,364
	$ 515,563	$ 465,617
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 24,777	$ 25,382
Fair value of commodity price contracts (Note 14)	478	20,622
	25,255	46,004
Bank indebtedness (Note 8)	100,993	78,834
Fair value of commodity price contracts (Note 14)	100	2,016
Decommissioning liability (Note 9)	24,474	18,983
	150,822	145,837
Shareholders' equity		
Share capital (Note 11)	391,444	389,316
Contributed surplus (Note 12)	12,014	8,870
Deficit	(38,717)	(78,406)
	364,741	319,780
Commitments (Note 18)		
	$ 515,563	$ 465,617

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director

Director

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

(Canadian $000s except per-share amounts)	Year Ended December 31, 2017	Year Ended December 31, 2016
Revenue		
Revenue from product sales	$ 123,306	$ 77,283
Royalties	(6,974)	(3,823)
Net revenue	$ 116,332	$ 73,460
Realized (loss) gain on commodity price contracts (Note 14)	(2,358)	4,505
Unrealized gain (loss) on commodity price contracts (Note 14)	24,627	(30,139)
Net revenue and commodity price contracts	$ 138,601	$ 47,826
Expenses		
Production	35,283	32,794
Transportation	4,446	2,186
General and administrative	6,158	5,337
Share-based compensation (Note 12)	3,816	3,124
Depletion and depreciation (Note 7)	44,229	39,510
Exploration and evaluation costs expensed (Note 6)	386	41
Accretion (Note 9)	454	347
Interest and finance costs	4,007	3,268
Unrealized revaluation loss on investments	133	120
Gain on sale of oil and gas properties	-	(441)
Total expenses	98,912	86,286
Net income (loss) and comprehensive income (loss) for the year	39,689	(38,460)
Net income (loss) per share (Note 13)		
- Basic and diluted	$ 0.33	$ (0.32)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s)				Year Ended December 31, 2017
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of year	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the year	-	-	39,689	39,689
Issue of common shares (Note 11)	1,456	-	-	1,456
Share-based compensation (Note 12)	-	3,816	-	3,816
Share-based compensation on options exercised (Note 11)	672	(672)	-	-
Balance, end of year	$ 391,444	$ 12,014	$ (38,717)	$ 364,741

(Canadian $000s)				Year Ended December 31, 2016
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of year	$ 385,766	$ 6,738	$ (39,946)	$ 352,558
Net loss for the year	-	-	(38,460)	(38,460)
Issue of common shares (Note 11)	2,558	-	-	2,558
Share-based compensation (Note 12)	-	3,124	-	3,124
Share-based compensation on options exercised (Note 11)	992	(992)	-	-
Balance, end of year	$ 389,316	$ 8,870	$ (78,406)	$ 319,780

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating activities		
Net income (loss) for the year	$ 39,689	$ (38,460)
Non-cash items:		
Unrealized (gain) loss on commodity price contracts (Note 14)	(24,627)	30,139
Depletion, depreciation and accretion (Notes 7 and 9)	44,683	39,857
Share-based compensation (Note 12)	3,816	3,124
Exploration and evaluation costs expensed (Note 6)	386	41
Unrealized revaluation loss on investments (Note 14)	133	120
Gain on sale of oil and gas properties (Note 7)	-	(441)
Funds flow	64,080	34,380
Net change in non-cash working capital items (Note 17)	(331)	(597)
	63,749	33,783
Financing activities		
Proceeds from issue of common shares (Note 11)	1,456	2,558
Increase in bank indebtedness	22,159	21,757
	23,615	24,315
Investing activities		
Additions to property and equipment (Note 7)	(79,847)	(64,136)
Additions to exploration and evaluation assets (Note 6)	(1,838)	(1,402)
Proceeds on disposal of exploration and evaluation assets (Note 6)	-	481
Proceeds on disposal of property and equipment (Note 7)	-	119
Net change in non-cash working capital items (Note 17)	(5,679)	6,840
	(87,364)	(58,098)
Change in cash during the year	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for years ended December 31, 2017 and 2016

Tabular amounts in thousands of Canadian dollars, except per share amounts

1. REPORTING ENTITY

Storm Resources Ltd. (the “Company” or "Storm"), is an oil and gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX under the symbol “SRX”. The Company operates primarily in the province of British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These audited consolidated financial statements (the “financial statements”) include the accounts of Storm and its wholly-owned subsidiary, Storm Gas Resource Corp. All inter-entity transactions have been eliminated upon consolidation. Storm’s operations are viewed as a single operating segment by the chief decision maker of the Company for the purpose of resource allocation and assessing asset performance.

2. BASIS OF PRESENTATION

Statement of Compliance

The financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on March 1, 2018.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior years, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 14.

3. SIGNIFICANT ACCOUNTING POLICIES

Exploration and Evaluation Expenditures

Exploration and evaluation (“E&E”) expenditures are accounted for in accordance with IFRS 6 - *Exploration for and Evaluation of Mineral Resources*, whereby costs associated with the exploration for and evaluation of oil and gas reserves are accumulated on an area-by-area basis and are capitalized as E&E assets when incurred. Future decommissioning costs relating to E&E activities are also included. Costs incurred in advance of land acquisition are charged to the consolidated statement of income (loss) in the period in which they are incurred; however, all other costs, including directly attributable general and administrative costs, are added to E&E assets.

No depletion or depreciation is provided for E&E assets. E&E costs are accumulated until technical feasibility and commercial viability of the assets is determined. Technical feasibility and commercial viability is typically evidenced by the allocation of proved or probable reserves to the assets or area. Once reserves are assigned to specific lands, the associated E&E assets are tested for impairment and the lesser of cost and the estimated recoverable amount is reclassified to property and equipment.

At each reporting date, E&E assets are reviewed for indicators of impairment and, if circumstances suggest that the carrying amount of a particular area exceeds its recoverable amount, the associated cost is written down to its estimated recoverable amount and the difference is accounted for as impairment expense on the consolidated statement of income (loss). If, at any time, it is determined that the Company has no future exploitation plans and commercial production cannot be achieved in relation to an area, the associated costs are written down to the estimated recoverable amount or fully de-recognized and the amount of the write-down is expensed on the consolidated statement of income (loss).

Property and Equipment

Property and equipment represents both intangible and tangible costs incurred in developing oil and natural gas reserves and maintaining or enhancing production from such reserves. Future decommissioning costs, related to producing assets, are also capitalized. Property and equipment is carried at cost, less accumulated depletion and depreciation and accumulated impairment losses. Gains and losses on disposal of property and equipment are determined as the difference between proceeds from disposal and the carrying amount of the asset sold and are recognized in the consolidated statement of income (loss).

Depletion and Depreciation

The net carrying amount of intangible oil and gas assets, categorized as property and equipment, is depleted using the unit-of-production method based on estimated proved and probable reserves, taking into account the future development costs required to produce the reserves.

Year-end proved and probable reserves are determined by independent engineers in accordance with Canadian National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil on the basis of six thousand cubic feet of gas to one barrel of oil. Changes in estimates used in prior periods, such as proved and probable reserves, that affect the unit-of-production calculations, do not give rise to prior year adjustments and are dealt with prospectively. Proved and probable reserves at the end of each interim reporting period are based on reserves determined at the immediately prior year end, adjusted for production and internal estimates of changes to reserves since the prior year end.

Tangible costs, such as processing facilities and well equipment, are depreciated on a straight-line basis over the estimated useful life of the facilities and equipment. Where facilities and equipment includes major components having different useful lives, they are depreciated separately.

Depreciation rates, useful lives and residual values are reviewed at each reporting date.

Impairment

The carrying amounts of property and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If such an indication exists, the estimated recoverable amount is calculated. For the purpose of impairment testing, property and equipment are grouped together into the smallest group of assets that generates cash inflows that are largely independent of the cash flows of other assets or group of assets (the "cash generating unit" or "CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs of disposal. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate and future commodity prices that reflect current market assumptions. Fair value less costs of disposal is the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal. An impairment loss is recognized in the consolidated statement of income (loss) if the carrying amount of an asset or CGU exceeds its estimated recoverable amount.

Impairment losses previously recognized are assessed at each reporting date for indications that the loss has decreased or no longer exists. If there has been an increase in the estimate of the recoverable amount an impairment loss is reversed to the extent that the asset's new carrying amount does not exceed the original carrying amount, net of related accumulated depletion and depreciation.

Business Combinations

Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case by case basis. Business combinations are accounted for at fair value using the acquisition method of accounting. The fair value of the net assets acquired and the consideration transferred is measured at the acquisition date. Associated transaction costs are expensed when incurred. Any excess of the cost of an acquisition over the net fair value of the net identifiable assets acquired is recognized as goodwill. If the consideration is less than the fair value of the net identifiable assets acquired, the difference is recognized as a gain in the consolidated statement of income (loss).

After initial recognition, goodwill is measured at cost less accumulated impairment losses. Goodwill is reviewed annually for impairment. Impairment losses on goodwill are not reversed.

No amounts in respect of goodwill have been recognized in the Company's financial statements.

Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term. Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within property and equipment and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term.

Decommissioning Liability

Decommissioning liabilities are measured as the present value of management's best estimate of the expenditure required to settle the future decommissioning liability at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is capitalized as part of E&E assets or property and equipment as appropriate. The amount capitalized to property and equipment is amortized on a unit-of-production basis consistent with the measurement of depletion. The obligation is adjusted at the end of each reporting period to reflect the passage of time and changes in the estimated future costs underlying the obligation. The increase in the obligation due to the passage of time is recognized as accretion expense in the consolidated statement of income (loss) whereas increases or decreases due to changes in the estimated future costs are capitalized. Actual costs incurred upon settlement of decommissioning obligations are charged against the liability; if actual costs exceed the liability recorded, the difference is charged to the consolidated statement of income (loss).

Revenue Recognition

Revenue associated with the sale of natural gas, condensate and NGL is recognized when title is transferred from Storm to its customers. Revenue is measured at the fair value of the consideration received. Revenue is recognized when all of the following conditions have been satisfied:

- The significant risks and rewards of ownership of production has been transferred to the buyer;
- Storm retains no managerial involvement or effective control over the production sold;
- The amount of revenue can be measured reliably; and
- It is probable that the economic benefits associated with the transaction will flow to Storm.

Transportation

Transportation expenses include costs incurred by the Company to transport natural gas, condensate and NGL from the wellhead to the point of title transfer.

Share-Based Compensation

The Company has issued options to acquire common shares to directors, officers and employees of the Company. These options are accounted for using the fair-value method which estimates the value of the options at the date of the grant using the Black-Scholes option pricing model. The fair value of each tranche of options thus established is recognized as compensation expense over the vesting period of the related options, with an equivalent increase to contributed surplus. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest. The effect of any revision in forfeiture rates is recognized in the consolidated statement of income (loss) with a corresponding adjustment to contributed surplus. When options are exercised, the proceeds, together with the amounts recorded in contributed surplus, are recorded in share capital.

Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. When the conditions of a grant relate to income or expenses, it is recognized in the consolidated statement of income (loss) in the period in which the expenditures are incurred or income is earned. When the conditions of a grant relate to an underlying asset, it is recognized as a reduction to the carrying amount of the related asset and amortized into income on a systematic basis over the expected useful life of the underlying asset through reduced depletion and depreciation expense.

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are de-recognized when the rights to receive cash flows from the instruments have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial instruments are measured at fair value upon initial recognition. Measurement in subsequent periods is dependent on the financial instrument's classification, as described below:

- *Fair value through profit or loss*
  Financial assets and liabilities classified as held-for-trading or designated at fair value through profit or loss are initially recognized and subsequently measured at fair value with subsequent changes in fair value charged to the consolidated statement of income (loss). The Company classifies its commodity price contracts as fair value through profit or loss.
- *Loans and receivables, held-to-maturity investments and other financial liabilities*
  Loans and receivables, held-to-maturity investments and other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest rate method, net of any impairment. The Company includes accounts receivable within the loans and receivable category, while accounts payable and accrued liabilities and bank indebtedness are classified as other financial liabilities.
- *Available-for-sale financial assets*
  Non-derivatives financial assets may be classified as available for sale as long as they are not classified in another category above. Available for sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income (loss), net of tax. Amounts recognized in other comprehensive income (loss) for available for sale financial assets are transferred to net income (loss) when realized through disposal or impairment.

Financial assets and liabilities are offset and the net amount reported in the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Derivative commodity price contracts

Derivative contracts may be used by the Company to manage exposure to market risks related to commodity prices, exchange rates and interest rates. Storm does not use derivative contracts for speculative purposes. The Company does not designate its derivative contracts as hedges and, as such, does not apply hedge accounting. All derivative contracts are classified at fair value through profit and loss.

Borrowing Costs

Borrowing costs attributable to the acquisition, construction or development of assets that require a considerable period of time to be ready for their intended use are added to the cost of those assets, until such time as the assets are substantially ready for use. All other borrowing costs are recognized as interest and finance costs in the consolidated statement of income (loss) in the period in which they are incurred.

Income Tax

Income tax comprises current and deferred taxes. Income tax is recognized in the consolidated statement of income (loss) except to the extent that it relates to items recognized directly in other comprehensive income (loss) or elsewhere in shareholders' equity, in which case the related income tax expense or recovery is similarly recognized.

Current tax expense is the expected cash tax payable on the taxable income for the year, using tax rates enacted, or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax expense and the related liability is recognized in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the reporting date and are expected to continue to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred income tax assets and liabilities are presented as non-current on the consolidated statement of financial position.

Jointly Controlled Assets and Operations

Certain of the Company's exploration and production activities are regarded as joint operations and are conducted under joint operating agreements, whereby two or more parties jointly control the assets. The financial statements reflect only the Company's share of these jointly controlled assets and, once production commences, Storm's proportionate share of the relevant revenue and related costs.

Share Capital

Proceeds from the issuance of common shares are classified as shareholders' equity. Costs directly attributable to the issuance of shares are recognized as a deduction from shareholders' equity.

Net Income (Loss) Per Share

Basic net income (loss) per share is calculated by dividing the net income (loss) attributable to equity owners for the reporting period by the weighted average number of common shares outstanding during the reporting period.

Diluted net income (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The Company's potentially dilutive instruments comprise stock options granted to directors, officers and employees. The number of shares included with respect to options is computed using the treasury stock method, which assumes that proceeds received from the exercise of in-the-money stock options are used to purchase common shares at average market prices.

4. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

There were no material new or amended accounting standards adopted during the year ended December 31, 2017.

Future Accounting Policy Changes

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts*. The standard is required to be adopted either retrospectively or using the modified transition approach for fiscal years beginning on or after January 1, 2018, with early adoption permitted. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company intends to retroactively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers and has concluded that the adoption of the new standard will result in presentation changes in revenue and transportation, which will not affect net income (loss) or funds flow. In addition, Storm will expand the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type.

In July 2014, the IASB issued IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected loss" impairment method and a substantially reformed approach to hedge accounting. Currently, the Company does not apply hedge accounting to its commodity price contracts nor does it intend to with adoption of IFRS 9. This standard is effective for annual periods beginning on or after January 1, 2018. The Company's financial assets primarily consist of accounts receivable and derivative commodity price contracts. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. The adoption of IFRS 9 will be applied on a retrospective basis on January 1, 2018 and will not have a significant effect on the valuation of the Company's financial assets.

In January 2016 the IASB issued IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for most leases. This standard replaces IAS 17 *Leases* and will be effective for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if IFRS 15 *Revenue from Contracts with Customers* is also adopted. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a "right-to-use asset" for essentially all lease contracts. The Company is currently identifying and analyzing contracts affected by the adoption of IFRS 16. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of this new standard will likely have a significant effect on the Company's financial statements.

5. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are continuously reviewed with the financial statement effect being recognized in the reporting period that the changes to estimates are made.

Critical judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are as follows:

Classification and Carrying Amount of Exploration and Evaluation Assets

Each reporting period, exploration and evaluation assets are subject to an internally conducted impairment review. Factors brought into the consideration of impairment include the Company's future plans for the property, lease expiries, drilling and development results on proximate or analogous properties, facility and pipeline access, views as to future commodity prices, operating and development costs and availability of capital for exploration and development programs. An impairment assessment is completed when the costs of exploration and evaluation assets are transferred to property and equipment. In the event an impairment provision is identified, the carrying amount of exploration and evaluation assets is reduced with the amount of the reduction being included in the consolidated statement of income (loss).

Carrying Amount of Property and Equipment

Each reporting period, property and equipment is subject to an impairment review applied at the CGU level. The impairment review gives recognition to changes in geological interpretation or development plans, drilling results, development costs, changes to reserve estimates and values, future commodity prices, facility and pipeline access, operating results, operating and future development costs, industry activity in the area, access to markets and availability of development capital.

Depletion, Impairment and Reserves

The amounts recorded for depletion and impairment testing are based on estimates of proved and probable reserves.

Assumptions that are valid at the time of reserve estimation may change materially as new information becomes available. Reserves estimates are based on engineering data, forward price estimates, production and future development costs, recovery rates or decommissioning costs, all of which may change the economic status of reserves and may ultimately result in reserves used for measurement purposes being removed from similar calculations in future reporting periods. Reserves have been evaluated at December 31, 2017 and 2016 by the Company's independent qualified reserves evaluator.

Decommissioning Liability

Measurement of the Company's decommissioning liability involves estimates as to the cost and timing of incurrence of future decommissioning programs. It also involves assessment of appropriate discount rates, rates of inflation applicable to future costs and the rate used to measure the accretion charge for each reporting period. Measurement of the liability also reflects current engineering methodologies as well as current and expected future environmental legislation and standards.

Measurement and Utilization of Tax Assets

The Company has tax pools which may be applied in reduction of future income. The amount of such pools is subject to audit by taxing authorities, possibly several years after the initial measurement. In addition, future changes to tax laws may result in the loss or limitation of use of such pools.

Measurement of Share-Based Compensation

The charge for share-based compensation involves the estimate of the fair value of stock options at time of issue. The estimate involves assumptions regarding the life of the option, dividend yields, interest rates, and volatility of the security subject to the option. The charge is measured using the Black-Scholes option pricing model, which could be replaced by a pricing model producing different results.

Carrying Amounts of Financial Instruments

Financial instruments are subject to valuation at the end of each reporting period. Generally the valuation is based on active and efficient markets. However, certain financial instruments may not be traded on an efficient market, or the market may disappear or be subject to circumstances or controls that impede the efficiency of the market.

6. EXPLORATION AND EVALUATION

	Year Ended December 31, 2017	Year Ended December 31, 2016
Balance, beginning of year	$ 110,395	$ 119,356
Additions	1,838	1,402
Expiries - exploration and evaluation costs expensed	(386)	(41)
Future decommissioning costs	192	100
Disposals	-	(100)
Transfer to property and equipment	(8,132)	(10,322)
Balance, end of year	$ 103,907	$ 110,395

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at December 31, 2017 and 2016 and none were identified.

7. PROPERTY AND EQUIPMENT

	Year Ended December 31, 2017	Year Ended December 31, 2016
Cost		
Balance, beginning of year	$ 466,700	$ 389,781
Additions	79,847	64,136
Future decommissioning costs	4,845	2,581
Disposals	-	(120)
Transfer from exploration and evaluation assets	8,132	10,322
Balance, end of year	$ 559,524	$ 466,700
Accumulated depletion and depreciation		
Balance, beginning of year	$ (126,336)	$ (86,826)
Depletion and depreciation	(44,229)	(39,510)
Balance, end of year	$ (170,565)	$ (126,336)
Net book value, beginning of year	$ 340,364	$ 302,955
Net book value, end of year	$ 388,959	$ 340,364

Future development costs for the year ended December 31, 2017 of $481.1 million (December 31, 2016 - $524.0 million) were included in the depletion calculation.

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2017, the Company determined that there were no indicators of impairment.

8. BANK INDEBTEDNESS

As at December 31, 2017, the Company had an extendible revolving credit facility in the amount of $165 million (December 31, 2016 – $130 million) based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until April 27, 2018, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one year later. Interest is paid on the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount of $165 million. At December 31, 2017, the Company is in compliance with all covenants under the credit facility.

As at December 31, 2017, the Company had issued letters of credit in the amount of $7.3 million (December 31, 2016 - $8.1 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

9. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning liability is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning liability is approximately $36.3 million (December 31, 2016 - $28.3 million), with the majority of payments being made in the years 2034 to 2054. A risk-free discount rate of 2.2% (December 31, 2016 – 2.2%) and an inflation rate of 2.0% (December 31, 2016 – 1.6%) was used to calculate the present value of the decommissioning liability, amounting to $24.5 million at December 31, 2017.

The following table provides a reconciliation of the carrying amount of the obligation:

	Year Ended December 31, 2017	Year Ended December 31, 2016
Balance, beginning of year	$ 18,983	$ 16,016
Obligations incurred	3,028	3,159
Obligations disposed	-	(61)
Change in estimates[1]	2,009	(478)
Accretion expense	454	347
Balance, end of year	$ 24,474	$ 18,983

(1) Relates to changes in inflation rates, risk-free discount rates and estimated settlement dates.

10. DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are based on the differences between the accounting amounts and the related tax bases of the Company's exploration and evaluation assets and property and equipment, commodity price contracts, decommissioning liability, share issue costs and unrealized gains and losses on investments.

The Company has tax pools associated with exploration and evaluation, property and equipment and share-issue costs of approximately $275.3 million as well as non-capital losses of approximately $204.2 million. The non-capital losses begin to expire in 2023. A deferred tax asset has not been recognized due to uncertainty as to future realization.

The provision for deferred income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial tax rates to pre-tax income for the year.

The differences are as follows:

	Year Ended December 31, 2017	Year Ended December 31, 2016
Net income (loss) for the year	$ 39,689	$ (38,460)
Statutory combined federal and provincial income tax rate	26.4%	26.4%
Expected income tax expense (recovery)	$ 10,473	$ (10,153)
Add (deduct) the income tax effect of:		
Share-based compensation	1,007	825
Change in unrecorded deferred income tax asset	(11,777)	9,395
Change in enacted corporate tax rate	277	-
Change in estimated tax pool balances	-	(86)
Other	20	19
Deferred income taxes	$ -	$ -

The components of the deferred income tax assets and liabilities are as follows. The net deferred tax asset has not been recognized/recorded.

	As at December 31, 2017	As at December 31, 2016
Deferred tax assets:		
Non-capital losses	$ 55,433	$ 55,007
Decommissioning liability	6,608	5,011
Fair value of commodity price contracts	-	5,849
Share issue costs	329	712
Investment	269	246
	$ 62,639	$ 66,825
Deferred tax liabilities:		
Property and equipment in excess of tax basis	$ (49,913)	$ (43,131)
Fair value of commodity price contracts	(667)	-
	$ (50,580)	$ (43,131)

11. SHARE CAPITAL

Authorized

An unlimited number of voting common shares without nominal or par value
An unlimited number of first preferred shares without nominal or par value

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2015	119,467	$ 385,766
Shares issued on stock option exercises(1)	1,297	3,550
Balance as at December 31, 2016	120,764	$ 389,316
Shares issued on stock option exercises(2)	793	2,128
Balance as at December 31, 2017	121,557	$ 391,444

(1) During 2016, 1,297,000 common shares were issued upon the exercise of stock options for proceeds of $2,558,000 and related prior period share-based compensation of $992,000 was transferred to share capital from contributed surplus.

(2) During 2017, 793,000 common shares were issued upon the exercise of stock options for proceeds of $1,456,000 and related prior period share-based compensation of $672,000 was transferred to share capital from contributed surplus.

(3) From the period from January 1 to March 1, 2018, no common shares were issued upon the exercise of stock options.

12. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at December 31, 2017, a total of 12,155,681 common shares were available for issuance, options in respect of 7,914,000 common shares were issued and outstanding and options in respect of 4,241,681 common shares were available for future issue.

In January 2018, the Company issued 2,394,700 options at an exercise price of $2.86 per common share.

At March 1, 2018, the date of this report, a total of 12,155,681 common shares are available for issuance under the stock option plan, options in respect of 9,936,700 common shares were issued and outstanding and 2,218,981 are available for future issue.

Details of the options outstanding at December 31, 2017 and December 31, 2016 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2015	7,753	$ 3.53
Granted during the year	2,031	$ 5.39
Exercised during the year	(1,297)	$ 1.97
Cancelled during the year	(100)	$ 4.04
Outstanding at December 31, 2016	8,387	$ 4.21
Granted during the year	320	$ 4.27
Exercised during the year	(793)	$ 1.83
Outstanding at December 31, 2017	7,914	$ 4.46
Number exercisable at December 31, 2017	5,610	$ 4.36

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$3.35 - $4.50	3,969	1.6	$ 3.85	3,072	$ 3.92
$4.51 - $5.50	3,945	1.7	$ 5.06	2,538	$ 4.89
Total	7,914	1.6	$ 4.46	5,610	$ 4.36

The fair value of employee stock options is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility, forfeiture rate, weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the year ended December 31, 2017 of $4.27 per share (2016 - $2.11 per share) include the following:

	2017	2016
Share price	$3.91 - $5.27	$4.90 - $5.50
Exercise price	$3.91 - $5.27	$4.90 - $5.50
Volatility	52%	52%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Risk-free interest rate	0.7% - 1.4%	0.6% - 0.9%

Share-based compensation expense of $3.8 million was charged to the consolidated statement of income (loss) during the year ended December 31, 2017 (2016 - $3.1 million) with an equivalent offset to contributed surplus.

13. NET INCOME (LOSS) PER SHARE

Basic and diluted net income (loss) per share were calculated as follows:

	Year Ended December 31, 2017	Year Ended December 31, 2016
Net income (loss) for the year	$ 39,689	$ (38,460)
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	120,764	119,467
Effect of shares issued	767	586
Weighted average number of common shares outstanding – basic	121,531	120,053
Dilutive effect of outstanding options(1)	85	-
Weighted average number of common shares outstanding - diluted	121,616	120,053
Net income (loss) per share		
Basic and diluted	$ 0.33	$ (0.32)

(1) Excludes the effect of 6.0 million weighted average common shares related to stock options that were anti-dilutive for the year ended December 31, 2017 (7.3 million weighted average common shares related to stock options for the year ended December 31, 2016).

14. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness and commodity price contracts.

Storm classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide continual and verifiable pricing information.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the years ended December 31, 2017 and December 31, 2016.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at December 31, 2017:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 6,212	$ (3,370)	$ 2,842
Long-term asset	268	(59)	209
Current liability	(3,848)	3,370	(478)
Long-term liability	(159)	59	(100)
Net position	$ 2,473	$ -	$ 2,473

As at December 31, 2016, the net financial liability and asset recognized in relation to the fair value of commodity price contracts was equal to the gross financial amounts as there were no offsets.

Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, marketing and financing activities such as:

- credit risk;
- market risk; and
- liquidity risk.

Management has primary responsibility for monitoring and managing financial risks under direction from the Board of Directors, which has overall responsibility for establishing the Company's risk management framework.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations.

Cash

When the Company has a cash surplus, it limits its exposure to credit risk by only investing in liquid securities and only with counterparties that have an acceptable credit rating or are supported by provincial government guarantees.

Derivative commodity price contracts

The Company enters into derivative commodity price contracts with counterparties with an acceptable credit rating and with a demonstrated capability to execute such contracts. The contracts, individually and in aggregate, are subject to controls established by the Board of Directors and limitations set out in the Company's banking agreement.

Accounts receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at December 31, 2017, the Company's most significant marketer accounted for $6.1 million (2016 - $8.0 million) of total receivables and 57% of total revenues (2016 – 64%). Where operations involve partners in a joint venture, the Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. Receivables from joint ventures are typically collected within one to three months of the joint venture bill being issued. As at December 31, 2017 and 2016, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at December 31, 2017.

The maximum exposure to credit risk at December 31, 2017 was the carrying amount of accounts receivable of $15.1 million and commodity price contract assets of $3.1 million.

A provision for impairment is established when there is objective evidence that the Company will not be able to collect all amounts due according to the original terms of the receivable. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganization and default or significant delinquency in payments are considered indicators that a trade receivable is impaired.

Market risk

Market risk is the risk that changes in market prices will affect the Company's income or the value of its financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

Market risks are as follows and are largely outside the control of the Company:

- commodity prices;
- interest rates; and
- foreign currency exchange rates.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil, natural gas, condensate and natural gas liquids are affected by many known and unknown factors such as demand and supply imbalances, market access, the relationship between the Canadian and United States dollar as well as national and international economic and geopolitical events.

The Company is exposed to the risk of declining prices for production resulting in a corresponding reduction in projected cash flow. Reduced cash flow may result in lower levels of capital being available for field activity, thus compromising the Company's capacity to grow total production while at the same time replacing continuous production declines from existing properties. Bank financing available to the Company is in the form of a reserves based loan, which is reviewed semi-annually, and is based on future cash flows and commodity price expectations. Changes to commodity prices will have an effect on credit available to the Company under its banking agreement.

The Company uses commodity price contracts to manage its exposure to fluctuations in commodity prices, by fixing prices of future deliveries of crude oil and natural gas and thus providing stability of cash flow. The Company does not use these instruments for trading or speculative purposes. Although the Company had no crude oil production at

December 31, 2017, part of its condensate and NGL stream is sold at a price based on crude oil. Accordingly, a financial investment based on crude oil is a proxy for the Company's condensate and NGL stream, as a direct investment is unavailable.

Fair values for commodity price contracts are based on quotes received from financial institution counterparties and are calculated using current market rates and prices and option pricing models using forward pricing curves and implied volatility.

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts, a net asset position of $2.5 million (December 31, 2016 – net liability of $22.2 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the year ended December 31, 2017, this resulted in an unrealized mark-to-market gain of $24.6 million (2016 – $30.1 million unrealized mark-to-market loss) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Jan – Feb 2018	4,000 Mmbtu	Chicago US$2.815/Mmbtu
Jan – Dec 2018	7,500 Mmbtu	Chicago Cdn$3.70/Mmbtu
Mar – Dec 2018	4,000 Mmbtu	Chicago Cdn$3.55/Mmbtu
Jan – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.01/Mmbtu
Jul – Dec 2018	12,000 Mmbtu	Chicago Cdn$3.51/Mmbtu
Jul – Dec 2018	3,000 Mmbtu	Chicago US$2.65/Mmbtu
Jan – Jun 2019	8,000 Mmbtu	Chicago Cdn$3.50/Mmbtu
Jan – Jun 2019	3,000 Mmbtu	Chicago US$2.65/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Crude Oil Collars		
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	450 Bbls	$62.78 - $71.67 Cdn$/Bbl
Jan – Jun 2019	300 Bbls	$64.00 - $72.37 Cdn$/Bbl
Crude Oil Swaps		
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Propane Swaps		
Jan – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl

For the year ended December 31, 2017, the Company realized a loss from commodity price contracts in place of $2.4 million (2016 – realized gain of $4.5 million).

Physical Delivery Sales Contract

The Company also enters into physical delivery sales contracts from time to time to manage commodity price risk. These contracts are considered normal executory contracts and are not recognized in the consolidated statement of income (loss) and comprehensive income (loss) until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Jan 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Interest rate risk

Interest on the Company's revolving bank facility varies with changes in core interest rates and is most commonly based on bankers acceptances issued by the Company's banks, plus a stamping fee. The stamping fee may change based on the Company's debt-to-cash-flow ratio for the previous quarter. The Company is thus exposed to increased borrowing costs during periods of increasing interest rates, with a corresponding reduction in both cash flows and project economics. In addition, a higher debt-to-cash-flow ratio will mean an increase in stamping fees, and correspondingly, interest rates.

The Company is exposed to interest rate risk in relation to interest expense on its revolving bank facility. Currently, the Company has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 basis points (1%) it is estimated that the Company's net income (loss) for the year ended December 31, 2017 would have decreased by $0.9 million. A decrease in interest rates by 1% would result in an increase in net income (loss) by an equivalent amount.

Foreign currency exchange rate risk

Prices for crude oil are determined in global markets and generally denominated in US dollars. Natural gas prices are largely influenced by both US and Canadian supply and demand structures. Changes in the Canadian dollar relative to the US dollar affect the Company's natural gas revenue, some of which is sold at a US$ price; therefore, variation in the Canadian-US dollar exchange rate will affect Canadian dollar prices for the Company's production. In addition, costs of imported materials used in the Company's operations will be affected by the Canadian-US dollar exchange rate.

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income (loss) due to changes in the fair value of commodity price contracts in place at December 31, 2017. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor	Year Ended December 31, 2017
Increase of US$10.00/Bbl in the price of WTI[(1)]	$ (6,593)
Decrease of US$10.00/Bbl in the price of WTI[(1)]	$ 5,582
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (2,275)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 2,301

(1) A portion of the Company's condensate and NGL production is sold at a price based on WTI.

Liquidity risk

Liquidity difficulties would emerge if the Company is unable to establish or maintain a profitable production base and thus generate sufficient cash flow to cover both operating and capital requirements. This may be the consequence of insufficient cash flows resulting from low product prices; production interruptions; operating or capital cost increases; unsuccessful investment programs; limitations in the Company's access to markets; or delays in bringing on stream new wells or facilities. These risks cannot be eliminated; however, the Company uses the following guidelines to address financial exposure:

- internal cash flow provides the initial source of funding on which the Company's capital expenditure program is based;
- debt, if available, may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled;
- equity, if available on acceptable terms, may be raised to fund acquisitions and exploration expenditures;
- farm-outs of projects may be arranged if management concludes that a project requires too much capital or where the project affects the Company's investment risk profile.

The timing of cash flows related to financial liabilities as at December 31, 2017 is as follows:

	Less than 1 year	2-3 years	Total
Accounts payable and accrued liabilities	$ 24,777	$ -	$ 24,777
Commodity price contracts	478	100	578
Bank indebtedness[(1)]	-	100,993	100,993
Total financial liabilities	$ 25,255	$ 101,093	$ 126,348

(1) Bank indebtedness is based on a revolving bank facility, which is reviewed annually. At renewal, the Company has the option to extend the facility for an additional year. If the revolving facility is not extended, the facility converts to a non-revolving facility payable in one year.

15. CAPITAL MANAGEMENT

The Company's capital structure comprises shareholders' equity and bank indebtedness. The Company's objective when managing capital is to maintain financial flexibility to support capital programs that will replace production sold as well as production declines and provide a base for future growth in production. Capital management involves the preparation of an annual budget, which is implemented after approval by the Company's Board of Directors. As the Company's business evolves throughout the year, the budget will be amended; however, any changes are again subject to approval by the Board of Directors.

Cash flow, bank financing and potential proceeds from the issue of equity and the sale of assets will be invested in exploration and development operations with the intent of growing short and medium term operating cash flow. It may be that capital currently available to the Company is insufficient to adequately grow cash flow, thus requiring additional capital which may be available only on terms dilutive to existing shareholders, if available at all. Growing cash flow enables the Company to increase bank or other debt financing, thus expanding capital available for investment.

16. RELATED PARTY TRANSACTIONS

Two directors of the Company are partners at law firms which have been engaged by the Company to provide legal services. During the year ended December 31, 2017, the Company incurred $0.1 million in legal fees and disbursements.

The remuneration of the key management personnel of the Company, which includes directors and officers, is set out below in aggregate:

	Year Ended December 31, 2017	Year Ended December 31, 2016
Salaries and short-term benefits	$ 2,446	$ 2,412
Share-based compensation	2,281	1,680
Total compensation	$ 4,727	$ 4,092

17. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2017	Year Ended December 31, 2016
Accounts receivable	$ (2,039)	$ (3,684)
Prepaids and deposits	(3,366)	(448)
Accounts payable and accrued liabilities	(605)	10,375
Change in non-cash working capital	$ (6,010)	$ 6,243
Relating to:		
Operating activities	$ (331)	$ (597)
Investing activities	(5,679)	6,840
Change in non-cash working capital	$ (6,010)	$ 6,243
Interest paid during the year	$ 3,369	$ 3,001
Income taxes paid during the year	$ -	$ -

18. COMMITMENTS

At December 31, 2017, the Company has the following long-term commitments over the next five years and thereafter:

	2018	2019	2020	2021	2022	Thereafter	Total
Natural gas transportation and processing commitments	$ 47,745	$ 33,384	$ 31,778	$ 21,754	$ 22,005	$ 182,843	$ 339,509
Office lease	670	-	-	-	-	-	670
Total	$ 48,415	$ 33,384	$ 31,778	$ 21,754	$ 22,005	$ 182,843	$ 340,179

In both 2017 and 2016 the Company made annual office lease payments of approximately $0.9 million which were included in general and administrative expense.

Subsequent to December 31, 2017, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years.

In February 2018, the Company entered into two natural gas transportation commitments with the first one commencing November 2020 for a term of 30 years and the second one commencing April 2021 for a term of 23 years, for a combined commitment of approximately $62 million.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & Chief Executive Officer

Robert S. Tiberio
Chief Operating Officer

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
President & Chief Executive Officer

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

(1) Member, Audit Committee (2) Member, Reserves Committee (3) Member, Compensation, Governance and Nomination Committee

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Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol "SRX"

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Canadian Imperial Bank of Commerce
Royal Bank of Canada
Calgary, Alberta

Executive Offices

Suite 200, 640 – 5th Avenue S.W.
Calgary, Alberta, T2P 3G4 Canada
Tel: (403) 817-6145 Fax: (403) 817-6146
www.stormresourcesltd.com

Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bpd	Barrels per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
HRB	Horn River Basin
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
NGL	Natural gas liquids
NYMEX	New York Mercantile Exchange
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

Storm Resources Ltd.
Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4
Phone: (403)817-6145   Fax: (403)817-6146

www.stormresourcesltd.com