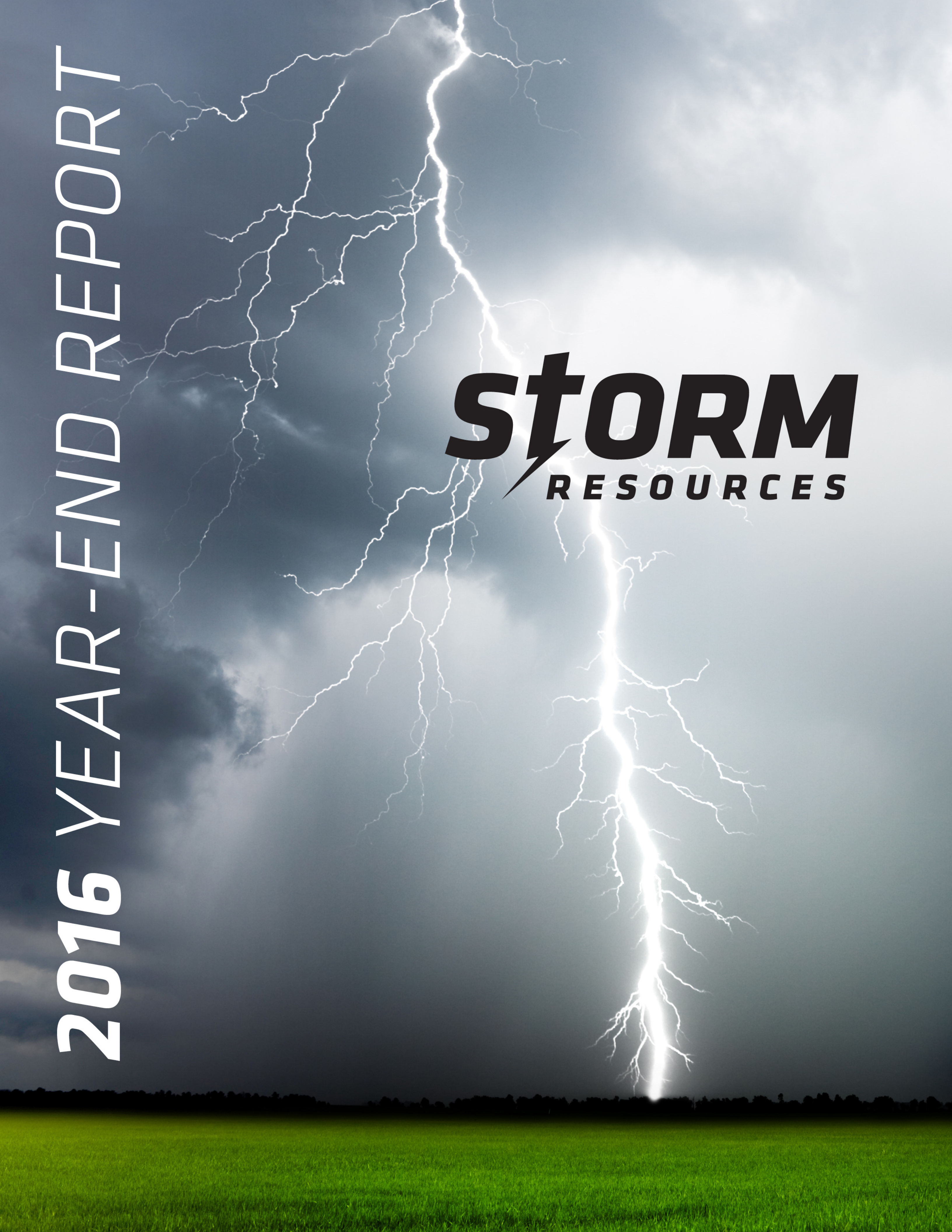
2016 YEAR-END REPORT

STORM RESOURCES



ANNUAL MEETING

The Annual General Meeting of shareholders will be held at 3:30 p.m. on Wednesday, May 17, 2017 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$, except volumetric and per-share amounts	Three Months to Dec. 31, 2016	Three Months to Dec.31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
FINANCIAL				
Revenue from product sales[1]	26,244	14,480	77,283	67,736
Funds flow	11,985	9,182	34,380	39,046
Per share - basic ($)	0.10	0.08	0.29	0.34
Per share - diluted ($)	0.10	0.08	0.29	0.34
Net income (loss)	(12,898)	1,850	(38,460)	(6,867)
Per share - basic ($)	(0.11)	0.02	(0.32)	(0.06)
Per share - diluted ($)	(0.11)	0.02	(0.32)	(0.06)
Operations capital expenditures[2]	33,399	30,998	65,538	95,099
Land and property acquisitions/(dispositions)	-	83	(600)	(23,590)
Debt including working capital deficiency[2][3]	89,841	61,721	89,841	61,721
Common shares (000s)				
Weighted average - basic	120,488	119,388	120,053	115,821
Weighted average - diluted	120,488	119,388	120,053	115,821
Outstanding end of period – basic	120,764	119,467	120,764	119,467
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales	21.42	14.67	15.97	18.64
Royalties	(0.99)	0.05	(0.79)	(0.82)
Production	(6.95)	(7.01)	(6.78)	(8.00)
Transportation	(0.55)	(0.79)	(0.45)	(1.13)
Field operating netback	12.93	6.92	7.95	8.69
Realized (losses) gains on hedging	(1.45)	4.20	0.93	4.20
General and administrative	(0.95)	(1.27)	(1.10)	(1.51)
Interest and finance costs	(0.74)	(0.54)	(0.68)	(0.62)
Funds flow per Boe	9.79	9.31	7.10	10.76
Barrels of oil equivalent per day (6:1)	13,320	10,730	13,219	9,956
Gas production				
Thousand cubic feet per day	66,173	53,147	65,478	48,656
Price (Cdn$ per Mcf)	2.86	1.78	2.05	2.39
Condensate production				
Barrels per day	1,381	1,072	1,303	997
Price (Cdn$ per barrel)	57.17	47.90	49.34	50.78
NGL production				
Barrels per day	910	800	1,003	670
Price (Cdn$ per barrel)	18.64	14.21	12.51	14.30
Oil production				
Barrels per day	-	-	-	179
Price (Cdn$ per barrel)	-	-	-	50.84
Wells drilled (100% working interest)	5.0	4.0	12.0	10.0
Wells completed (100% working interest)	5.0	6.0	10.0	12.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements including operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 37 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2016 FOURTH QUARTER HIGHLIGHTS

- Production was 13,320 Boe per day (17% condensate and NGL), a year-over-year increase of 24% (23% on a per-share basis) and flat on a quarter-over-quarter basis. With the improvement in natural gas prices late in the quarter, two additional standing horizontal wells were turned on and production increased in December to 14,670 Boe per day.

- Condensate and NGL production increased 22% from the previous year to average 2,291 barrels per day. Condensate and NGL volumes are now being reported separately with condensate including field condensate plus pentane recovered at gas plants while NGL is the propane and butane recovered at gas plants.

- Montney horizontal well performance at Umbach continues to improve as the length and number of frac stages are increased. The first seven wells completed in 2016 with enough production history averaged 5.3 Mmcf per day gross raw gas over the first 90 calendar days, a 10% improvement from the average 2014 and 2015 wells.

- Controllable cash costs (production, general and administrative, interest and finance) were $8.64 per Boe.

- Funds flow was $12.0 million ($9.79 per Boe), an increase of 31% from a year ago and a 173% increase when realized gains and losses from hedging are excluded. The increase was driven by a 24% increase in production volumes.

- Net loss was $12.9 million which includes an unrealized mark to market hedging loss of $13.9 million (excluding the unrealized hedging loss, net profit was $1.0 million or $0.01 per share).

- Capital investment was $33.4 million including $11.8 million for construction of the third field compression facility at Umbach which was started up on January 12, 2017. In addition, five horizontal wells (5.0 net) were drilled and five horizontal wells (5.0 net) were completed.

- At the end of the quarter, there was an inventory of nine horizontal wells (9.0 net) that had not started producing (includes three completed wells).

- Debt including working capital deficiency was $89.8 million which is 1.9 times annualized fourth quarter funds flow (the bank credit facility is $130.0 million).

- Commodity price hedges continue to be layered in with approximately 40% of forecast 2017 production currently hedged.

2016 YEAR-END HIGHLIGHTS

- Production for the year averaged 13,219 Boe per day (17% condensate and NGL), a year-over-year increase of 34% on a per-share basis.

- During 2016, seven horizontal wells were turned on which offset declines and maintained production at approximately 13,000 Boe per day through November. Production in December increased to 14,670 Boe per day after two more horizontal wells were turned on.

- Controllable cash costs (production, general and administrative, interest and finance) averaged $8.56 per Boe for the year, a decrease of $1.57 per Boe or 15% from the previous year. Production costs declined to $6.78 per Boe, an improvement of 15%.

- Capital investment totaled $64.9 million with $22.4 million to drill 12.0 net horizontal wells, $18.5 million to complete 10.0 net horizontal wells and $23.1 million for infrastructure ($18.8 million or 29% of 2016 capital investment was for the third field compression facility at Umbach).

- The average cost to drill and complete a Montney horizontal well at Umbach in 2016 was $3.9 million, a decrease of 11% from 2015.

- Storm entered into a natural gas processing arrangement at Umbach with Spectra Energy ("Spectra") which is effective January 1, 2017 and is expected to reduce corporate operating costs by approximately 15% to 20%.

- Proved developed producing ("PDP") reserves increased 21% per share, additions replaced 195% of production and the all-in Finding, Development & Acquisition ("FD&A") cost was $6.89 per Boe ($4.90 per Boe excluding $18.8 million for the third field compression facility at Umbach which started up in January 2017).

- Total proved ("1P") reserves increased 4% per share, additions replaced 175% of production and the all-in FD&A cost was $4.97 per Boe.

- Total proved plus probable ("2P") reserves increased 2% per share, additions replaced 172% of production and the all-in FD&A cost was $5.48 per Boe.

- All reserve additions in the 2016 evaluation were from Storm's 100% working interest lands at Umbach. Wells completed in 2016 were assigned average 2P reserves of 5.8 Bcf gross raw gas with the actual drill and complete cost being $3.9 million. The actual results were an improvement over what was recognized in last year's evaluation where average 2P reserves of 4.7 Bcf were assigned to future drilling locations with an estimated drill and complete cost of $4.5 million.

- The corporate decline rate was approximately 33% in 2016 (December 2015 corporate production was 13,602 Boe per day with the same wells producing 9,210 Boe per day in December 2016).

- Cost of production additions in 2016 was $12,800 per Boe per day using total capital investment and fourth quarter production of 5,080 Boe per day from wells starting production in 2016 (last year was $11,000 per Boe per day). This is reduced to $9,100 per Boe per day when the $18.8 million invested in the third field compression facility is excluded (approximates the sustaining cost to maintain production).

SUMMARY OF YEAR-END RESERVE EVALUATION

The year-end reserve evaluation is effective December 31, 2016 and was prepared by InSite Petroleum Consultants Ltd. ("InSite"), independent qualified reserve evaluators of Calgary, Alberta.

Reserves

(Mboe)	**2016 vs 2015**	**2016**	**2015**	**2014**
PDP	22%	25,395	20,810	13,487
1P	5%	77,097	73,434	59,551
2P	3%	104,192	100,722	88,024
PDP as % of 2P		24%	21%	15%
1P as a % of 2P		74%	73%	68%

- Reserve quality continues to improve with PDP increasing to 24% of 2P from 21%.
- PDP reserve growth was consistent with growth in corporate production while 1P and 2P reserve growth was limited by fewer step-out wells being drilled (more infill wells were drilled to improve capital efficiency in response to the significant decline in commodity prices and funds flow).
- Technical revisions added 7% to PDP, 4% to 1P and 3% to 2P.

Reserves Per Share Outstanding (Mboe per million shares)	**2016 vs 2015**	**2016**	**2015**	**2014**
PDP	21%	210	174	121
1P	4%	638	615	535
2P	2%	862	844	791

- Reserve growth on a per-share basis was reduced by issuance of 1.3 million shares for exercised stock options.

Future Development Capital ("FDC") ($ million)	**2016**	**2015**	**2014**
1P	$413	$435	$448
2P	$524	$543	$607

- The year-over-year decline in FDC resulted from a decrease in the number of future drilling locations. With fewer step-out wells drilled, the number of future drilling locations that were added (7.0 net 2P) was less than the number of wells drilled (12.0 net).
- The cost to drill and complete a future horizontal well in the Montney at Umbach in the 2016 evaluation was $4.5 million which is unchanged from 2015.
- FDC is fully funded by forecast net operating income.

All-in FD&A Cost Including Change in FDC ($/Boe)	**2016**	**2015**	**2014**	**3 Year Total**
PDP	$6.89	$6.53	$23.01	$11.48
1P	$4.97	$3.38	$11.68	$8.68
2P	$5.48	$0.50	$9.64	$7.18

- The all-in FD&A cost reflects the result of Storm's entire capital investment program, including acquisitions, dispositions and revisions.
- PDP FD&A is the most realistic as it reflects actual financial results (actual capital spending and actual well results). 1P and 2P FD&A is less likely to reflect past or future financial results given they are largely based on estimates of future well performance, estimates of future FDC, and changes to estimates of future FDC.

Recycle Ratio Using All-in FD&A Cost	**2016**	**2015**	**2014**	**3 Year Total**
Field operating netback including hedging	$8.88	$12.89	$19.93	$12.76
PDP Recycle	1.3	2.0	0.9	1.1
1P Recycle	1.8	3.8	1.7	1.5
2P Recycle	1.6	25.8	2.1	1.8

- Recycle ratios were weak in 2016 primarily as a result of very low natural gas prices in the first half of 2016 (AECO averaged $1.53 per GJ) which reduced revenue and the field operating netback.

Net Present Value Discounted @ 10% Before Tax **InSite Price Forecast December 31, 2016** ($ million)	**2016 vs 2015**	**2016**	**2015**	**2014**
PDP	+49%	$317	$213	$199
1P	+36%	$600	$442	$493
2P	+28%	$758	$592	$684

- Net present value improved primarily from forecast operating costs being reduced over the life of the reserves by 21% for PDP (to $7.28 per Boe from $9.27 per Boe) and 25% for both 1P and 2P.
- Revenue over the life of the reserves increased 7% (+$2.06 per Boe) for PDP and decreased 1% and 3% for 1P and 2P respectively.

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 108,000 net acres (154 net sections). To date, Storm has drilled 58 horizontal wells (54.4 net).

Production in the fourth quarter was 12,945 Boe per day and liquids recovery was 36 barrels per Mmcf sales with 60% being higher priced field condensate plus pentanes recovered at the gas plant. Year over year, the number of producing wells has increased by 9.0 net wells while production has increased by 21%.

During the fourth quarter, five horizontal wells (5.0 net) were drilled, five horizontal wells (5.0 net) were completed and three horizontal wells (3.0 net) started production. At the end of the fourth quarter, there was an inventory of nine horizontal wells (9.0 net) that had not started producing which included three completed wells.

Activity in the first quarter of 2017 will include drilling six horizontal wells (6.0 net) and completing four horizontal wells (4.0 net).

With start-up of the third field compression facility on January 12, 2017, field compression now totals 115 Mmcf per day raw gas. Throughput in the fourth quarter averaged 68 Mmcf per day raw gas and has averaged approximately 90 Mmcf per day raw gas in January and February 2017. The third field compression facility has initial capacity of 35 Mmcf per day with the estimated final cost being $25.0 million (2015: $4.8 million, 2016: $18.8 million, 2017: $1.4 million) and it is expandable to 70 Mmcf per day for an additional $7.0 million. Once the expansion is completed, total capacity will be 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day.

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where firm processing commitments average 75 Mmcf per day raw gas in 2017. A new processing arrangement with Spectra at the McMahon Gas Plant started on January 1, 2017, has a total commitment of 65 Mmcf per day of raw gas at terms ranging from 5 to 15 years, and is expected to reduce corporate operating costs by 15% to 20%. The arrangement with Spectra supports future growth with an option to increase contracted capacity and provides for continued diversification of natural gas sales as the McMahon Gas Plant is connected to three sales pipelines (Alliance Pipeline to Chicago, TransCanada NGTL system to AECO, Spectra T-north to BC Station 2).

A summary of horizontal well performance and costs is provided below. For the wells completed in 2016, the drill and complete cost declined by 22% on a per-stage basis from 2015 and the IP90 improved by 13%. The majority of future horizontal wells are expected to have greater than 1,600 metres of completed length with more than 30 frac stages.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP 90 Cal Day Mmcf/d Raw	IP 180 Cal Day Mmcf/d Raw	IP 365 Cal Day Mmcf/d Raw
2013 6 hz's	17	1,190 m	$4.6 million $270 K/stage	3.5 Mmcf/d 6 hz's	2.9 Mmcf/d 6 hz's	2.2 Mmcf/d 6 hz's
2014 12 hz's*	19	1,170 m	$4.6 million $240 K/stage	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	$4.4 million $200 K/stage	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 10 hz's
2016 10 hz's	25	1,301 m	$3.9 million $156 K/stage	5.3 Mmcf/d 7 hz's	4.8 Mmcf/d 3 hz's	
2017 4 hz's	35	1,671 m				

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

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the Horn River Basin (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well averaged 310 Boe per day in the fourth quarter. Cumulative production to date from this well is 5.3 Bcf raw.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer term growth by providing some certainty regarding future revenue and funds flow. The objective is to hedge 50% of most recent quarterly or monthly production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. The WTI price is also hedged given that approximately 80% of Storm's liquids production is priced in reference to WTI (condensate, plant pentane and butane). The hedge position is updated periodically in the presentation posted on Storm's website. For 2017, approximately 40% of forecast production is currently hedged.

2017		
Crude Oil	875 Bopd	WTI Cdn$64.57/Bbl floor, Cdn$69.55/Bbl ceiling
Natural Gas	34,100 GJ/d (27,200 Mcf/d)	AECO Cdn$2.66/GJ ($3.32/Mcf)
	9,200 Mmbtu/d (7,750 Mcf/d)	Chicago Cdn$4.17/Mmbtu ($4.93/Mcf)
2018		
Crude Oil	260 Bopd	WTI Cdn$63.38/Bbl floor, Cdn$70.53/Bbl ceiling
Natural Gas	750 GJ/d (600 Mcf/d)	AECO Cdn$2.80/GJ ($3.50/Mcf)
	10,900 Mmbtu/d (9,200 Mcf/d)	Chicago Cdn$4.00/Mmbtu ($4.73/Mcf)

The Company also has natural gas price differential hedges in place (Chicago – AECO and AECO – BC Station 2) with details provided in Note 14 to the financial statements.

Storm's strategy with respect to natural gas transportation commitments is to mitigate risk by diversifying sales and selling at multiple points including Chicago, AECO and BC Station 2. As per the summary below, transportation commitments total 72 Mmcf per day in 2017 and increase to 102 Mmcf per day in 2018 (in addition to this firm capacity, interruptible capacity on the Alliance Pipeline adds up to 14 Mmcf per day in 2017 and up to 15 Mmcf per day in 2018). During the fourth quarter, the deduction from revenue for Alliance transportation was $6.6 million. Further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

2017	**2018**
Alliance Pipeline(1) 51 Mmcf/d Chicago price 5 Mmcf/d ATP price	Alliance Pipeline(1) 55 Mmcf/d Chicago price 5 Mmcf/d ATP price
Spectra T-north 16 Mmcf/d BC Stn 2 price	Spectra T-north 29 Mmcf/d BC Stn 2 price
	Spectra T-north & TCPL 13 Mmcf/d AECO price

(1) Interruptible capacity on the Alliance Pipeline adds up to 25% of contracted capacity.

ORGANIZATIONAL UPDATE

On November 15, 2016, the pending retirements of Mr. Donald McLean, Chief Financial Officer, and Mr. John Devlin, Vice President, Finance, were announced. Both are planning to retire in mid-2017. Successors joined Storm in late 2016 and will be announced when 2017 first quarter results are released on May 15, 2017.

OUTLOOK

Production in the first quarter of 2017 is forecast to be 16,000 to 17,000 Boe per day (January and February averaged 16,500 Boe per day based on field estimates). Capital investment in the first quarter is expected to be approximately $30.0 million and will include drilling six horizontal wells, completing four horizontal wells and $8.0 million for pipelines plus a second fuel gas conditioning unit at Umbach (back-up to avoid downtime associated with equipment failures).

Guidance for 2017 is largely unchanged from what was previously provided except for updating commodity prices.

2017 Guidance

	Initial Guidance September 7, 2016	Updated November 15, 2016	Updated March 2, 2017
Chicago natural gas (US$/Mmbtu)	$3.00	$3.00	$3.00(1)
AECO natural gas (Cdn$/GJ)	$2.65	$2.65	$2.50(1)
BC Stn 2 natural gas (Cdn$/GJ)	$2.25	$2.20	$2.00(1)
Edmonton light oil (Cdn$/bbl)	$55	$55	$59(1)
Estimated average operating costs ($/Boe)	$5.50 - $5.75	$5.50 - $5.75	$5.50 - $6.00
Estimated average royalty rate (% production revenue before hedging)	9% - 11%	9% - 11%	9% - 11%
Estimated operations capital ($ million) (excluding acquisitions & dispositions)	$75.0 - $80.0	$75.0 - $80.0	$75.0 - $80.0
Estimated cash G&A - $ million	$5.3	$5.3	$5.3
- $/Boe	$0.85	$0.85	$0.85
Forecast fourth quarter production (Boe/d) % condensate and NGL	18,000 – 20,000 17%	18,000 – 20,000 17%	18,000 – 20,000 17%
Forecast annual production (Boe/d) % condensate and NGL	16,500 – 18,000 17%	16,500 – 18,000 17%	16,500 – 18,000 17%
Umbach horizontal wells drilled	12 gross (12.0 net)	12 gross (12.0 net)	12 gross (12.0 net)
Umbach horizontal wells completed	13 gross (13.0 net)	14 gross (14.0 net)	14 gross (14.0 net)
Umbach horizontal wells connected	15 gross (15.0 net)	15 gross (15.0 net)	15 gross (15.0 net)

(1) Assumed commodity prices are approximately equal to realized prices to date and the current forward strip.

2017 Guidance History

	Chicago (US$/mmbtu)	BC Station 2 (Cdn$/GJ)	AECO (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

Capital investment in 2017 will be directed entirely to Umbach and will include $55.0 million for drilling and completions plus $21.0 million for infrastructure (pipelines, wellsite equipping, facilities). Approximately 55% will be invested in the first half of 2017. A cost of $4.2 million is assumed for drilling and completing a horizontal well at Umbach, an increase of 8% from the 2016 actual cost. There is flexibility in the capital program and investment may be adjusted up or down depending on commodity prices and funds flow which will affect forecast production. Commodity price hedges will partially mitigate potential declines in pricing.

Storm's infrastructure plan at Umbach will support growth to 27,000 Boe per day which is approximately double average production in the fourth quarter of 2016. Depending on natural gas pricing and funds flow, preliminary planning would see this achieved in the second half of 2018.

An effort has been made to diversify natural gas sales which will mitigate the effect of the recent widening of price differentials with US markets. Approximately 84% of forecast natural gas production in 2017 is covered by firm transportation agreements with 60% to be sold at Chicago, 18% at BC Station 2 and 6% at Alliance Transfer Point ("ATP"). The remainder will be sold at BC Station 2 and/or Chicago using interruptible pipeline capacity. For January 2017, approximately 66% of production was sold at Chicago, 27% at BC Station 2 and 7% at ATP.

The outlook for natural gas prices remains positive as a result of a tighter supply/demand balance in the United States. Data from the Energy Information Administration ("EIA") shows that 2016 production declined by 1.6 Bcf per day while 2016 demand increased by 0.5 Bcf per day, a year-over-year deficit of 2.1 Bcf per day. Based on the EIA Short Term Energy Outlook February 2017, exports are forecast to increase a further 1.3 Bcf per day in 2017 (primarily LNG and Mexico) which increases the deficit to 3.4 Bcf per day if production doesn't decline any further. Over the last five years, almost all of the growth in US production has come from the Marcellus/Utica region and increasing production to meet higher demand will require higher natural gas prices as many producers in the Marcellus/Utica have higher cost structures and receive lower prices after pipeline tariffs are deducted. Longer term, the outlook is increasingly bullish with demand continuing to increase as a result of five LNG export facilities currently operating or under construction on the US Gulf Coast, plus US pipeline capacity to Mexico is expected to increase by more than 6 Bcf per day by the end of 2018 from six new pipelines.

Western Canadian natural gas prices relative to US markets have weakened with the NYMEX – AECO price differential widening to -US$1.08 per Mmbtu in January 2017 from -US$0.56 per Mmbtu in January 2016. This is the result of production growth exceeding demand growth which has mostly been from the Alberta oilsands as export pipelines to the US are fully contracted and eastern Canada demand has been flat to declining. Storm's exposure to Western Canadian pricing is primarily at BC Station 2 where prices can be volatile because it's a smaller market in terms of trading volumes, especially if there are outages or restrictions on the TCPL system which causes more natural gas to be directed to BC Station 2 (more than 50% of NE BC production is directed onto TCPL to AECO). Price volatility will be mitigated by using interruptible capacity to maximize sales onto the Alliance Pipeline, hedging the AECO – BC Station 2 price differential and by reducing production growth if the price is too low to generate an acceptable rate of return.

Storm is still in the early stages of delineating the large and high quality resource in the Montney formation at Umbach. The relatively shallow depth results in a lower cost to drill and complete horizontal wells (12 days to drill and case a well) while liquids recovery increases revenue (36% of revenue in 2016 was from condensate and NGL). With 154 net sections, there remains room for significant future growth with producing horizontal wells on only 7% of the lands (10 net sections) and proved plus probable reserves assigned on only 21% of the lands (33 net sections). Most of this land position is expected to be economically exploitable given results from Storm's wells and encouraging results achieved by other operators on adjacent lands.

With multiple years of drilling inventory in the Montney at Umbach, the focus continues to be on increasing net asset value per share by converting resource into per-share growth in production and funds flow. At current forward strip commodity prices, annual average and fourth quarter production is forecast to increase by more than 30% in 2017 and the preliminary plan is for a further 25% to 35% increase in 2018. Reducing costs is also important (in all price environments) and further improvement is expected in 2017 as operating costs decline from the new processing arrangement with Spectra while the cost of adding PDP reserves will decline by drilling longer horizontal wells to increase rates and reserves.

In closing, I would like to thank Storm's employees for their considerable efforts in 2016 which resulted in record levels of production, continuing improvements in capital efficiency and a further reduction in controllable cash costs. In addition, I would like to thank Storm's Board of Directors whose advice, guidance and support continue to be invaluable.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

March 2, 2017

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 2, 2017 for the three months and year ended December 31, 2016.

RESERVES AT DECEMBER 31, 2016

Storm's year-end reserve evaluation effective December 31, 2016 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated of February 24, 2017. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2016 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, 2016 (the "AIF").

Summary

- Reserve additions in 2016 replaced 195% of production for proved developed producing ("PDP"), 175% for total proved ("1P") and 172% for total proved plus probable ("2P").

- 2P reserves include 529 Bcf of natural gas and 16 Mmbbl of NGL at year-end 2016. The NGL component includes 60% condensate (9.6 Mmbbl), 24% butane (3.8 Mmbbl) and 16% propane (2.6 Mmbbl).

- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $6.89 per Boe for PDP, $4.97 per Boe for 1P and $5.48 per Boe for 2P.

- Technical revisions were primarily due to horizontal well performance exceeding the InSite forecast from the previous year which increased PDP reserves by 1,392 Mboe (7%), 1P reserves by 3,319 Mboe (5%) and 2P reserves by 3,419 Mboe (3%).

- Breaking down 2P reserves by area, 96.3% is at Umbach, 3.3% is at the HRB and 0.4% is at Grande Prairie.

- Future development costs ("FDC") were $412.8 million on a 1P basis and $524.0 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.

- At Umbach, the 100% working interest lands were assigned 61 net 2P horizontal drilling locations at an average of 4.9 Bcf gross raw gas (last year was 66 net 2P locations with 4.7 Bcf gross raw gas). On the 60% working interest lands, 20.4 net 2P horizontal drilling locations were assigned an average of 3.7 Bcf gross raw gas (unchanged from last year).

- For the wells drilled in 2016 at Umbach, ultimate 2P recovery is forecast to average 5.6 Bcf gross raw gas.

- At Umbach, 2P reserves were recognized in the upper Montney only on 21% or 32.6 net sections of Storm's 154 net sections in the area (an increase of 2.2 net sections from last year). DPIIP averages 48 Bcf gross raw gas per section in the upper Montney (total net DPIIP 1.6 Tcf on 32.6 net sections). Forecast recovery of DPIIP totals 36% for 2P reserves.

- Umbach 2P FDC includes $53.0 million net for future infrastructure expansion (last year was $31.0 million net for future infrastructure expansion).

- The estimated cost to drill and complete a future Montney horizontal well at Umbach was unchanged year over year at approximately $4.5 million (actual cost in 2016 was $3.9 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, 2016, 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, 2016
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	128,363	4,001	25,395
Proved non-producing	6,175	194	1,223
Total proved developed	134,538	4,195	26,618
Proved undeveloped	255,980	7,815	50,479
Total proved	390,518	12,011	77,097
Probable additional	138,591	3,997	27,095
Total proved plus probable	529,109	16,007	104,192

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2016
(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, 2015 - opening balance	20,810	73,434	27,288	100,722
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	8,032	5,182	(292)	4,890
Category transfer	-	-	-	-
Dispositions	-	-	-	-
Technical revisions	1,392	3,319	100	3,419
Economic factors	-	-	-	-
Production	(4,838)	(4,838)	-	(4,838)
December 31, 2016 – closing balance	25,395	77,097	27,096	104,192

Numbers in this table may not add due to rounding.

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

(years)	2016	2015	2014
PDP	5.2	5.3	3.6
1P	15.9	18.8	15.9
2P	21.4	25.7	23.5

The 1P and 2P RLI declined as a result of fewer step-out wells being drilled which limited additions to reserves and due to fourth quarter 2016 production increasing by 24% from fourth quarter 2015.

Future Development Costs ("FDC")

	Proved ($M)	Proved Plus Probable ($M)
2017	68,700	82,350
2018	125,613	161,058
2019	151,763	170,584
2020	66,697	97,154
2021	-	12,827
Remainder	-	-
Total FDC - undiscounted	412,773	523,972
Total FDC - discounted at 10%	347,044	435,644
Umbach	$400.4 million	$495.1 million
HRB	$ 12.3 million	$ 28.9 million

Note: InSite escalates capital costs at 2% per year after 2017.
Numbers in this table may not add due to rounding.

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

Proved Developed Producing FD&A Cost (All-In)	2016	2015	2014	3 Year Total
Net capital investment (000s)	$ 64,938	$ 71,509	$ 194,555	$ 331,002
Total capital	$ 64,938	$ 71,509	$ 194,555	$ 331,002
Total reserve additions (Mboe)	9,424	10,956	8,456	28,836
All-in PDP FD&A cost (per Boe)	$ 6.89	$ 6.53	$ 23.01	$ 11.48

Total Proved FD&A Cost (All-In)	2016	2015	2014	3 Year Total
Net capital investment (000s)	$ 64,938	$ 71,509	$ 194,555	$ 331,002
Change in FDC (000s)	(22,669)	(12,275)	288,242	253,298
Total capital including change in FDC (000s)	$ 42,269	$ 59,234	$ 482,797	$ 584,300
Total reserve additions (Mboe)	8,501	17,517	41,334	67,352
All-in 1P FD&A cost (per Boe)	$ 4.97	$ 3.38	$ 11.68	$ 8.68

Total Proved Plus Probable FD&A Cost (All-In)	2016	2015	2014	3 Year Total
Net capital investment (000s)	$ 64,938	$ 71,509	$ 194,555	$ 331,002
Change in FDC (000s)	(19,395)	(63,288)	287,686	205,003
Total capital including change in FDC (000s)	$ 45,543	$ 8,221	$ 482,241	$ 536,005
Total reserve additions (Mboe)	8,308	16,332	50,030	74,670
All-In 2P FD&A cost (per Boe)	$ 5.48	$ 0.50	$ 9.64	$ 7.18

NI 51-101 Finding and Development Costs ("F&D") (excluding acquisitions, dispositions and revisions)

Total Proved F&D Cost	2016	2015	2014	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 64,938	$ 95,099	$ 106,604	$ 266,641
Change in FDC (000s)	(22,669)	18,604	288,242	284,177
Total capital including change in FDC (000s)	$ 42,269	$ 113,703	$ 394,846	$ 550,818
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	5,182	14,950	38,707	58,863
1P F&D cost (per Boe)	$ 8.16	$ 7.61	$ 10.20	$ 9.36

Total Proved Plus Probable F&D Cost	2016	2015	2014	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 64,938	$ 95,099	$ 106,604	$ 266,641
Change in FDC (000s)	(19,395)	30,717	287,686	299,008
Total capital including change in FDC (000s)	$ 45,543	$ 125,816	$ 394,290	$ 565,649
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	4,890	19,457	45,001	69,371
2P F&D cost (per Boe)	$ 9.31	$ 6.47	$ 8.76	$ 8.15

Net Present Value Summary (before tax) as at December 31, 2016

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	486,861	383,254	316,836	271,495	238,896
Proved non-producing	21,559	16,257	12,978	10,806	9,285
Total proved developed	508,420	399,511	329,814	282,301	248,181
Proved undeveloped	660,527	416,812	270,511	177,437	115,375
Total proved	1,168,947	816,323	600,324	459,738	363,556
Probable additional	511,202	272,727	157,811	96,661	61,309
Total proved plus probable	1,680,149	1,089,050	758,135	556,398	424,865

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2016

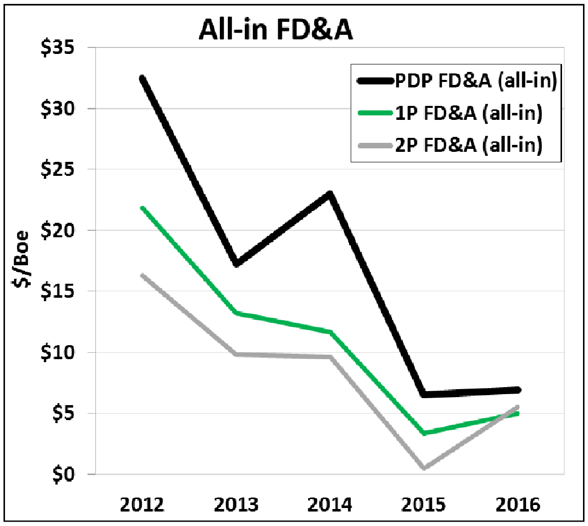
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

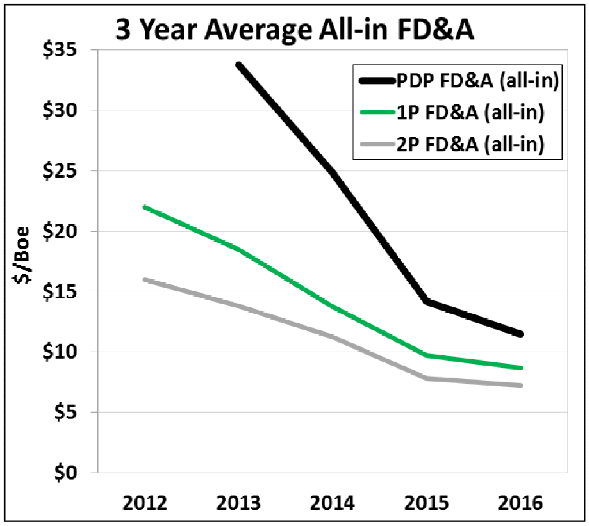
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	478,916	379,518	315,007	270,567	238,410
Proved non-producing	15,916	13,256	11,326	9,870	8,741
Total proved developed	494,832	392,774	326,333	280,437	247,151
Proved undeveloped	487,961	303,815	192,667	121,593	73,984
Total proved	982,794	696,588	519,001	402,030	321,134
Probable additional	378,529	199,417	112,882	66,808	40,221
Total proved plus probable	1,361,323	896,005	631,883	468,838	361,355

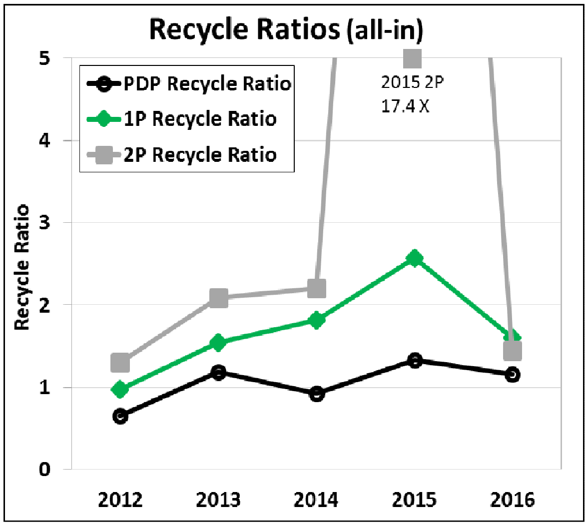
Numbers in this table may not add due to rounding.

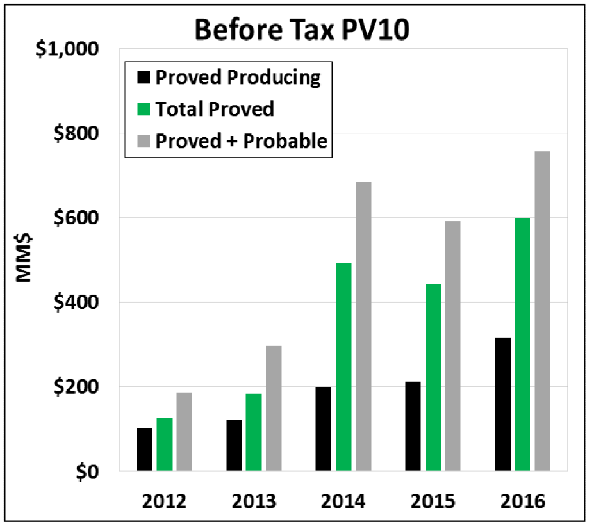
InSite Escalating Price Forecast as at December 31, 2016

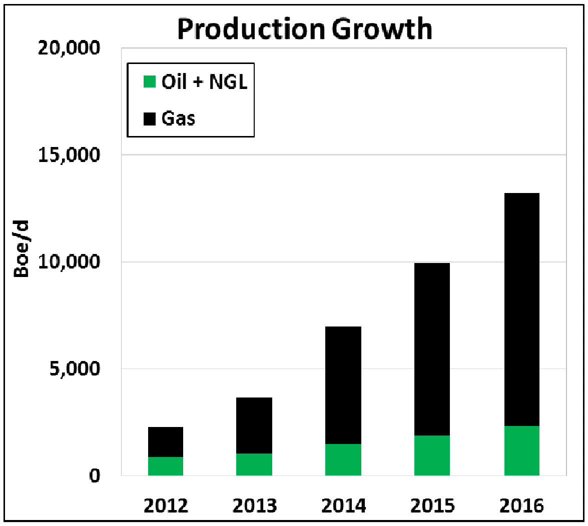
	WTI Crude Oil (US$/Bbl)	Edmonton Par Crude Oil (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)
2017	55.00	68.33	3.50	3.47
2018	60.00	72.32	3.50	3.42
2019	65.00	76.05	3.75	3.59
2020	70.00	79.54	3.90	3.93
2021	75.00	82.82	4.10	4.01

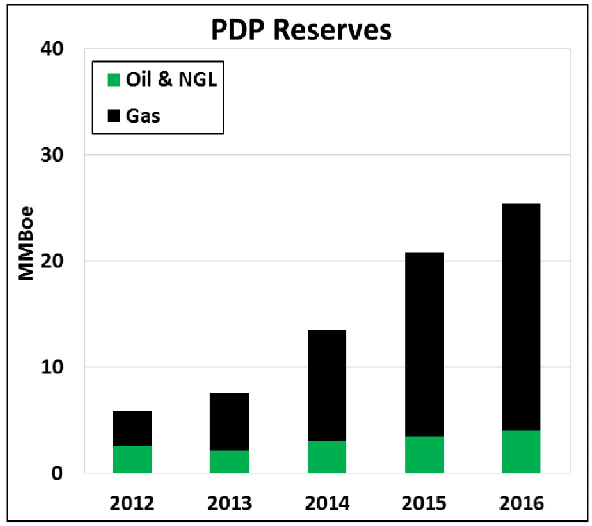


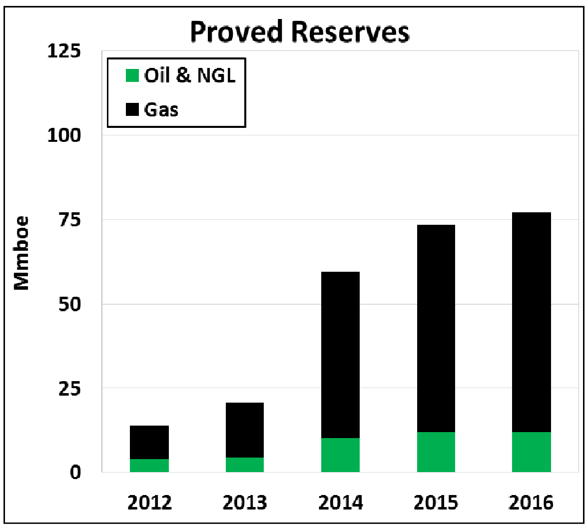


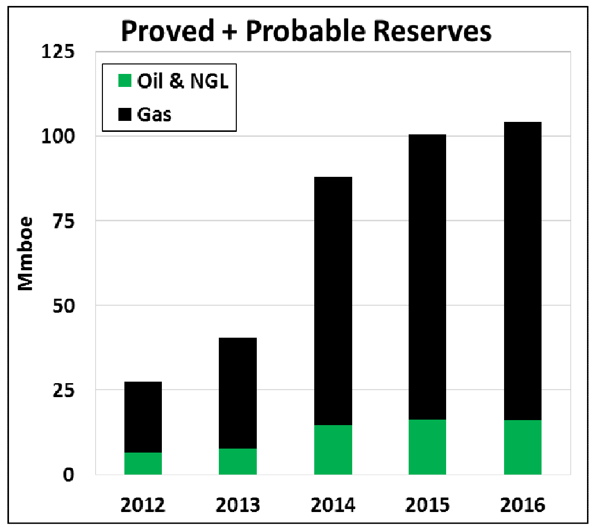


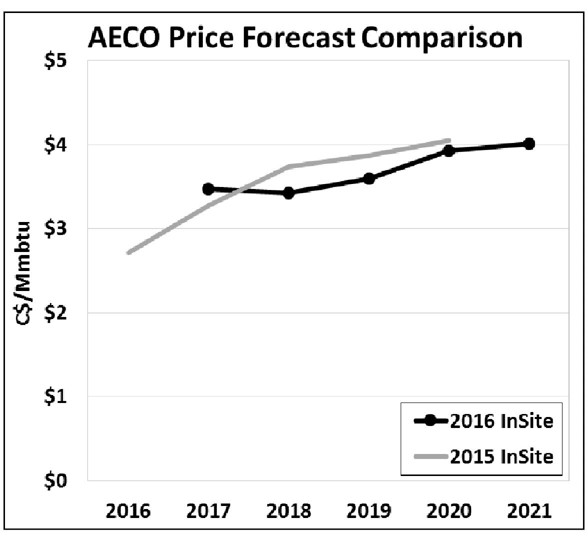


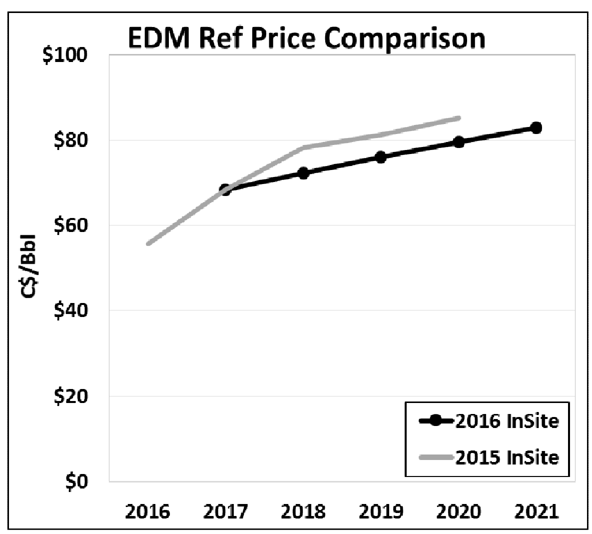

Production Growth
Oil + NGL
Gas
Boe/d
20,000
15,000
10,000
5,000
0
2012
2013
2014
2015
2016


PDP Reserves
Oil & NGL
Gas
MMBoe
40
30
20
10
0
2012
2013
2014
2015
2016


Proved Reserves
Oil & NGL
Gas
Mmboe
125
100
75
50
25
0
2012
2013
2014
2015
2016


Proved + Probable Reserves
Oil & NGL
Gas
Mmboe
125
100
75
50
25
0
2012
2013
2014
2015
2016


AECO Price Forecast Comparison
C$/Mmbtu
$5
$4
$3
$2
$1
$0
2016 InSite
2015 InSite
2016
2017
2018
2019
2020
2021


EDM Ref Price Comparison
C$/Bbl
$100
$80
$60
$40
$20
$0
2016 InSite
2015 InSite
2016
2017
2018
2019
2020
2021

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, 2016. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2016 and 2015, (ii) each of the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2016, and (iii) the press release issued by the Company on March 2, 2017, 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 TSX Venture Exchange under the symbol "SRX".

This MD&A is dated March 2, 2017.

See "Forward-Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 36 to 37.

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, 2016 and the unaudited interim consolidated financial information for the three months ended December 31, 2016, 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, 2016 and 2015. The reporting and the measurement 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, 2015.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Year to December 31, 2016

Coming off what proved to be a challenging 2015, any renewed optimism due to the start of a new year was short lived given continued weakness in commodity prices, specifically the natural gas tape, which saw the AECO benchmark average $1.53 per GJ for the first half of the year. An abnormally warm 2015-2016 winter coupled with an abundance of natural gas supply led to record storage levels across North America. This continues to be a cause for concern in the market today. In Canada, robust growth from the Western Canadian Sedimentary Basin, specifically the Montney and Spirit River plays, paired with a lack of egress to natural gas markets further exacerbated the issue, resulting in downward pressure on both AECO and Station 2 prices. However, for Storm, new marketing arrangements that came into effect late in 2015 saw a shift in markets for the Company's production, with approximately 70% of natural gas molecules in the year being sold in the Chicago market, where prices held up better relative to the Canadian benchmark. Storm also benefited from a stronger US dollar relative to the Canadian dollar. The shift to Chicago compares to the prior year when approximately 50% of the Company's natural gas production was sold at the Station 2 index price.

While representing only 17% of the Company's total production base, condensate (includes field condensate and plant pentanes) and NGL (includes butane and propane) remain a meaningful contributor to the Company's top line revenue, with the majority of condensate and NGL revenue streams being based on crude oil reference prices. Nevertheless, the effect of a worldwide supply glut of crude oil hit home as prices plummeted to a 13-year low early in the year before embarking on a modest recovery.

For context, both natural gas and crude oil benchmark prices continued their downward spiral into the first half of 2016 with the AECO reference price bottoming out in the second quarter at $1.18/GJ, while the Edmonton light oil price hit a low of $40.81/Bbl in the first quarter. These levels reflected a 53% and 23% reduction, respectively, from the already depressed levels achieved in the fourth quarter of 2015 and brought activity across the industry to a grinding halt. For illustration, Storm's realized natural gas price in the second quarter of 2016 was $1.28 per Mcf, a period in which the Company incurred only $0.6 million of capital expenditures.

Changes in capital expenditures for the year resulted in guidance being amended by the Company as set out in the table below:

2016 Guidance History

	Chicago Spot (US$/Mmbtu)	AECO Spot (Cdn$/GJ)	BC Station 2 Spot (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
August 13, 2015		$2.80	$2.40	$106.0	20,000 - 21,000	16,000 - 19,000
November 11, 2015		$2.50	$1.90	$105.0	20,000 - 21,000	16,000 - 18,000
February 25, 2016	$2.20	$2.00	$1.45	$80.0	15,500 - 16,500	14,000 - 15,000
May 12, 2016	$2.20	$1.60	$1.25	$37.0 - $42.0	13,000 - 14,000	12,500 - 13,500
August 15, 2016	$2.40	$1.95	$1.65	$36.0 - $50.0	13,000 - 14,000	12,500 - 13,500
September 7, 2016	$2.40	$1.95	$1.65	$70.0	13,000 - 14,000	12,500 - 13,500
November 15, 2016	$2.45	$2.00	$1.65	$65.0 - $70.0	13,000 - 14,000	12,500 - 13,500
Actual 2016 Results	**$2.48**	**$2.05**	**$1.64**	**$64.9**	**13,320**	**13,219**

The precipitous drop in commodity prices prompted a swift response from Storm with capital expenditures reduced by approximately $25.0 million in February from levels contemplated in our initial 2016 guidance, followed by a further reduction of approximately $40.0 million in early May. The Company's response to improved prices later in the year resulted in the restoration of $25.0 million in capital expenditures, illustrative of the Company's ability to react quickly to pricing shifts. The benefit of these actions was twofold: firstly, preservation of the value of the Company's inventory as adequate rates of return could not be achieved in such a low commodity price environment; and, secondly, protection of the Company's balance sheet. Fiscal prudence has always and will continue to be of the utmost importance in managing both the short and long-term plans for the Company. After selling substantially all of Storm's Alberta properties in July 2015 for proceeds of $23.6 million, the Company entered 2016 in a position of financial strength with bank borrowings of only $57.1 million, or 41%, of the Company's credit facility at the time. This low debt level provided enough financial flexibility to weather the commodity price downturn, while providing the ability to accelerate capital into the back half of the year upon confirmation of a strengthening in commodity prices, thus setting the Company up to continue with growth initiatives on its Montney play at Umbach. Debt including working capital deficiency at year-end amounted to $89.8 million, or 1.9 times annualized fourth quarter 2016 funds flow, with $78.8 million drawn on the Company's $130.0 million credit facility.

Year over year, total production grew by 33%, 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 in response to low natural gas prices while also affected by third party constraints. In response to price weakness, Storm will shut in production in excess of volumes required to satisfy processing and transportation obligations: absent any other factors, production will not be sold at a price below its replacement cost.

Year-over-year production costs per Boe fell by 15%, while the total of general and administrative and interest and finance costs per Boe fell by 16%. However, increased production and an improving cost structure were insufficient to offset the fall in commodity pricing with the result that year-over-year funds flow fell by 12%. Funds flow for the first half of 2016 was down 38% year over year, with the price rally late in the year being too little too late to make up for the shortfall from the dismal first half. Storm's active hedging program continued to play a role in providing financial stability, with realized hedging gains totaling $4.5 million, or 6%, of revenue from product sales, although short of the realized hedging gains of $15.3 million, or 22%, of revenue from product sales achieved in the prior year.

Similar to 2015, the Company's capital program in 2016 was exclusively focused on the Umbach property, with net capital expenditures totaling $64.9 million, virtually all of which was spent on property and equipment. A total of $40.9 million was spent on drilling and completions and $23.1 million on infrastructure. At the beginning of 2016, Storm had an inventory of six standing wells of which four awaited completion. Twelve wells (100% working interest) were drilled in the year with nine wells being brought on production, resulting in an inventory of nine wells drilled with six awaiting completion at the end of 2016. Storm can thus replace production declines, or add production in 2017, at a relatively modest cost. Recall, in December 2015, the Company entered into arrangements to diversify marketing and transportation, which resulted in a higher natural gas price with production correspondingly increasing to approximately 13,600 Boe per day. In light of the commodity price environment in 2016 and a significantly reduced capital program, this level of production was essentially held flat, averaging 13,219 Boe per day, for the year. Storm's facility capacity was in the range of 14,000-15,000 Boe per day for 2016, although with construction of the third field compression facility completed in January 2017 this increased to a range of 19,000-20,000 Boe per day. Commodity prices and funds flow will drive the Company's capital program in 2017, which is expected to have a continued focus on Umbach. The Umbach property offers reasonable year round access: thus activity levels can be readily increased or reduced in response to commodity price movements. The capital program for 2017 is flexible and can be subject to amendment throughout the year. Storm's longer-term business plan will not change – what may change is timing of execution.

Improved pricing in the second half of the year resulted in additions to Storm's hedge book. The increased stability of budgeted funds flow in 2017, coupled with a general improvement in the industry environment, resulted in the Company bringing forward start-up of a third field compression facility at Umbach from the second quarter of 2017 to January of 2017. With the new facility now on stream, Storm's compression capacity is currently 115 Mmcf of raw gas per day. The final cost of the new facility is estimated to be $25.0 million and was financed with Storm's existing financial resources. Of this amount $5.0 million was incurred in 2015, $19.0 million in 2016 and the remaining amount in the first quarter of 2017. The new field compression facility will be twinned in due course for an incremental cost of $7.0 million. Completion and the future twinning of the new facility will increase Storm's potential production base from current levels to volumes of approximately 27,000 Boe per day.

During 2015 and 2016, Storm analysed the design, operation and financing associated with constructing a gas processing facility, commissioning of which would have resulted in a considerable reduction in operating costs. After an extensive review, it was determined that this avenue was not currently in the best interests of the Company as a higher rate of return could be achieved by drilling and completing horizontal wells supported by a new processing arrangement with Spectra Energy ("Spectra"). As disclosed in early September, the Company entered into an additional processing agreement with Spectra which should result in corporate operating costs falling by approximately 15-20% from 2016 levels. Further, the Spectra agreement is effective January 1, 2017, whereas reductions in operating costs from plant ownership would only have emerged in mid-to-late 2018. The additional processing agreement does not preclude Storm from revisiting the construction of a Company owned gas plant when production levels exceed those covered by processing agreements.

Quarter Ending December 31, 2016

The fourth quarter of 2016 was the Company's strongest quarter, financially, of 2016. Production was 24% higher than the fourth quarter of 2015, although flat compared to the third quarter of 2016. Revenue from product sales for the quarter was 81% higher than the prior year amount, with per-Boe revenue being 46% higher than the 2015 amount and 24% higher than the immediately preceding quarter. Production for the months of October and November averaged approximately 12,650 Boe per day, with production for December increasing to approximately 14,700 Boe per day, a level that was ramped up further after start-up of the third field compression facility with production averaging 16,500 Boe per day in January and February based on field estimates. Increased production in December 2016 was driven by a rally in natural gas prices.

Funds flow for the quarter totaled $12.0 million, approximately 31% higher than the same period in the prior year and 37% greater than the third quarter of 2016. Increased funds flow over the preceding quarter resulted primarily from improved pricing in the current period coupled with the receipt of royalty credits in December. Using annualized funds flow for the fourth quarter, the ratio of year-end debt including working capital deficiency to funds flow amounted to 1.9 times.

Capital expenditures for the quarter totaled $33.4 million. Included in this amount were drilling and completion costs of $19.8 million, corresponding to the drilling of five wells along with the completion of five wells in the quarter. Facility, equipping and gathering costs totaled $13.4 million including equipment costs relating to the third field compression facility which was brought on stream in January 2017.

During the fourth quarter, the Company's bank syndicate confirmed Storm's bank facility at $130.0 million, which was 61% drawn at the end of the fourth quarter. The annual review is set to take place prior to April 28, 2017.

Production and Revenue

Production by Area

The Company reported production from the following areas:

Producing Area	Year Ended December 31, 2016 Natural Gas (Mcf/d)	Condensate(1) (Bbls/d)	Natural Gas Liquids(2) (Bbls/d)	Crude Oil(3) (Bbls/d)	Boe/d	Year Ended December 31, 2015 Natural Gas (Mcf/d)	Condensate(1) (Bbls/d)	Natural Gas Liquids(2) (Bbls/d)	Crude Oil(3) (Bbls/d)	Boe/d
Umbach NE BC	64,644	1,303	1,003	-	13,080	46,084	982	657	-	9,320
Horn River Basin NE BC(4)	680	-	-	-	113	1,044	-	-	-	174
Grande Prairie AB(1)(4)	154	-	-	-	26	1,528	15	13	179	462
Total	65,478	1,303	1,003	-	13,219	48,656	997	670	179	9,956

Producing Area	Three Months Ended December 31, 2016 Natural Gas (Mcf/d)	Condensate(1) (Bbls/d)	Natural Gas Liquids(2) (Bbls/d)	Crude Oil(3) (Bbls/d)	Boe/d	Three Months Ended December 31, 2015 Natural Gas (Mcf/d)	Condensate(1) (Bbls/d)	Natural Gas Liquids(2) (Bbls/d)	Crude Oil(3) (Bbls/d)	Boe/d
Umbach NE BC	63,916	1,381	911	-	12,945	53,142	1,072	800	-	10,729
Horn River Basin NE BC(4)	1,863	-	-	-	310	-	-	-	-	-
Grande Prairie AB(1)(4)	394	-	(1)	-	65	5	-	-	-	1
Total	66,173	1,381	910	-	13,320	53,147	1,072	800	-	10,730

(1) Includes field condensate and plant pentanes.
(2) Includes butane and propane.
(3) Crude oil properties were sold in the third quarter of 2015.
(4) Production shut in for part of period due to pricing.

Average Boe per day production volumes in 2016 increased by 33% when compared to 2015. The year-over-year increase in production for natural gas, condensate and NGL came from Umbach where the Company started production from nine new 100% working interest wells during the year.

In the fourth quarter of 2016, average Boe per day production volumes increased by 24% when compared to the fourth quarter of 2015. Production of natural gas amounted to 83% of total Boe production in the fourth quarter of 2016, consistent with earlier quarters of the year as production at Umbach was held reasonably constant throughout the year in response to low commodity prices.

Production volumes for both the full year and the fourth quarter of 2016 approximated 83% natural gas, 10% condensate and 7% NGL.

Average Daily Production

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Natural gas (Mcf/d)	66,173	53,147	65,478	48,656
Condensate (Bbls/d)	1,381	1,072	1,303	997
Natural gas liquids (Bbls/d)	910	800	1,003	670
Crude oil (Bbls/d)	-	-	-	179
Total (Boe/d)	13,320	10,730	13,219	9,956

Low natural gas prices in the first half of 2016 resulted in production being reduced to the level required to meet firm processing and transportation commitments. Improved pricing later in the year resulted in shut-in production being restored. In December 2016 production increased to approximately 14,700 Boe per day, illustrative of the ability of the Company's production base to respond quickly to commodity price movements.

Daily production per million shares outstanding at the end of 2016 averaged 109 Boe per day, compared to 83 Boe per day in 2015, an increase of 31%. Daily production per million shares for the fourth quarter of 2016 averaged 110 Boe per day compared to 90 Boe per day for the fourth quarter of 2015.

Production Profile and Per-Unit Prices(1)

	Three Months to Dec. 31, 2016		Three Months to Dec. 31, 2015		Year Ended Dec. 31, 2016		Year Ended Dec. 31, 2015	
	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas - Mcf	83%	$ 2.86	83%	$ 1.78	83%	$ 2.05	81%	$ 2.39
Condensate - Bbl	10%	57.17	10%	47.90	10%	49.34	10%	50.78
Natural gas liquids - Bbl	7%	18.64	7%	14.21	7%	12.51	7%	14.30
Crude oil - Bbl	-	-	-	-	-	-	2%	50.84
Per Boe	100%	$ 21.42	100%	$ 14.67	100%	$ 15.97	100%	$ 18.64

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

Following the introduction of new marketing arrangements late in 2015, the Company's production during 2016 was sold as follows:

- 41% - Adjusted Chicago monthly index price less US$0.05 per Mmbtu
- 28% - Adjusted Chicago daily index price
- 18% - Station 2 daily spot price
- 12% - AECO daily index price less Cdn$0.68 per GJ
- 1% - ATP

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$1.35 per GJ) as title to the gas transfers at the natural gas processing plant in British Columbia.

A summary of reference prices for 2016 and 2015 for each market is set out below. Note that pricing comparability between markets is affected by foreign exchange and lack of uniformity between commodity units. Storm's realized prices also differ due to heat content of the Company's natural gas. Noteworthy is the disparity between Canadian and US index prices and the remarkable improvement in Station 2 pricing in the fourth quarter of 2016 when compared to any quarter in the prior twelve months.

A summary of reference prices for 2016 and 2015 is as follows:

	Storm Realized Natural Gas Price (Cdn$/Mcf)	Chicago Monthly Index (US$/Mmbtu)	Chicago Daily Index (US$/Mmbtu)	AECO Daily Index (Cdn$/GJ)	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Light Oil (Cdn$/Bbl)
2016							
Q1	1.62	2.25	2.04	1.74	2.00	1.33	40.81
Q2	1.28	1.95	2.09	1.33	1.18	1.14	54.78
Q3	2.41	2.76	2.78	2.20	2.09	1.83	54.80
Q4	2.86	3.00	2.97	2.93	2.67	2.27	61.58
Average - 2016	2.05	2.49	2.47	2.05	1.98	1.64	52.99
2015							
Q1	2.85	3.43	3.28	2.81	2.80	2.02	51.93
Q2	2.55	2.68	2.70	2.52	2.53	2.01	67.72
Q3	2.46	2.83	2.79	2.75	2.65	1.72	56.23
Q4	1.78	2.47	2.16	2.34	2.51	1.04	52.95
Average - 2015	2.39	2.85	2.73	2.55	2.62	1.70	57.21

In 2015, transmission interruptions and curtailments in Alberta resulted in increased natural gas volumes moving to the Station 2 market. Further, natural gas production also increased in geographic areas where production is normally directed to Station 2. The consequence was a considerable widening in the AECO daily index – Station 2 differential with average Station 2 prices for 2015 at a discount to AECO daily index of $0.85 per GJ. The pipeline restrictions that contributed to the widening differential started to resolve late in 2015 and into 2016 resulting in a differential of $0.41 per GJ in the first quarter of 2016, $0.19 per GJ in the second quarter, $0.37 per GJ in the third quarter and $0.66 per GJ in the fourth quarter of the year. The volatility and risk associated with Station 2 pricing is expected to increase for the foreseeable future in light of continued production growth from the Montney in northeast British Columbia.

Storm's natural gas realized price for 2016 was $2.05 per Mcf, broadly in line with the average AECO monthly benchmark price for the year. Benefits of stronger Chicago pricing, net of transportation, including a favorable US$/Cdn$ exchange rate as well as higher heat content sales gas at Umbach, were offset by lower Station 2 pricing.

Storm's liquids stream in 2016 contained approximately 57% condensate, which is generally priced with reference to benchmark pricing for crude oil. Storm received an average price of $49.34 per barrel for the year for condensate, only 3% shy of that realized in 2015. For 2016, WTI averaged US$43.32 per barrel and Edmonton light oil was Cdn$52.99 per barrel, resulting in a US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$4.39 per barrel, compared to Cdn$5.10 per barrel in 2015. The realized price for NGL, excluding condensate, in 2016 fell 13% relative to 2015, largely due to lower butane prices. Propane continued to face headwinds for much of the year, although posted an impressive rally late in the year that carried into 2017.

Increasing natural gas production at Umbach has resulted in growing volumes of higher value condensate. The significance of this is illustrated by the contribution from this revenue stream, which comprised 10% of Boe production but amounted to 30% of revenue from product sales in 2016.

On a per-Boe basis, the Company's average realized price for 2016 declined by 14% when compared to 2015, although the fourth quarter witnessed a resurgence in commodity prices resulting in a 46% increase when comparing the fourth quarter periods.

Revenue from Product Sales

(000s)	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Natural gas	$ 17,423	$ 8,710	$ 49,151	$ 42,436
Condensate	7,259	4,724	23,541	18,469
Natural gas liquids	1,562	1,046	4,591	3,500
Crude oil	-	-	-	3,331
Total	$ 26,244	$ 14,480	$ 77,283	$ 67,736

Revenue from product sales for 2016 increased by 14% when compared to 2015, with an average price per Boe for 2016 of $15.97, a year-over-year decrease of 14%. Production volumes grew by 33%, however, the effect of this was muted due to the rapid fall in commodity prices in the first half of the year which began to reverse in the third quarter, picking up more momentum in the fourth quarter through to the end of the year.

Revenue from product sales for the fourth quarter of 2016 increased by 81% when compared to the fourth quarter of 2015 and by 25% when compared to the immediately preceding quarter. Quarterly production volumes grew 24% year over year, although were essentially flat when compared to the third quarter of 2016. Pricing was stronger in the fourth quarter of 2016, increasing 46% per Boe over the fourth quarter of 2015, while increasing 24% over the third quarter of 2016.

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

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – 2015	$ 42,436	$ 18,469	$ 3,500	$ 3,331	$ 67,736
Effect of changes in production	14,828	5,736	1,754	-	22,318
Effect of changes in average product prices	(8,113)	(664)	(663)	-	(9,440)
Disposition	-	-	-	(3,331)	(3,331)
Revenue from product sales - 2016	$ 49,151	$ 23,541	$ 4,591	$ -	$ 77,283

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Crude Oil(1)	Total
Revenue from product sales – Q4 2015	$ 8,710	$ 4,724	$ 1,046	$ -	$ 14,480
Effect of changes in production	2,135	1,357	145	-	3,637
Effect of changes in average product prices	6,578	1,178	371	-	8,127
Revenue from product sales – Q4 2016	$ 17,423	$ 7,259	$ 1,562	$ -	$ 26,244

(1) Crude oil production was sold in the third quarter of 2015.

Realized and Unrealized Gains (Losses) on Commodity Price Contracts

The realized gain (loss) on commodity price contracts comprises cash settlements on contracts which, in whole or in part, have come to term during the reporting period, plus cash settlements relating to contracts which the Company terminated during the reported period.

The term liquids below refers to crude oil contracts. Although the Company has no crude oil production, much of the condensate and NGL stream is priced with reference to crude oil. In the absence of a liquid market for condensate and NGL price contracts, the Company may enter into crude oil contracts as a proxy for a condensate and NGL hedge.

The unrealized gain (loss) on commodity price contracts is a non-cash charge resulting from the year-over-year and quarter-over-quarter change in the fair value of commodity price contracts outstanding at the end of the reporting period. The change in fair value recognizes the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period and also removes the opening value of contracts which have come to term during the reporting period.

	Year Ended Dec. 31, 2016			Year ended Dec. 31, 2015		
Realized gain (loss)						
Natural gas	$ 1,260	$ 0.05	/Mcf	$ 10,114	$ 0.57	/Mcf
Liquids	3,245	$ 3.85	/Bbl	5,137	$ 78.42	/Bbl
Total realized gain (loss) – cash(1)	$ 4,505	$ 0.93	/Boe	$ 15,251	$ 4.20	/Boe

	Year Ended Dec. 31, 2016			Year Ended Dec. 31, 2015		
Unrealized gain (loss)						
Natural gas – change in fair value	$ (23,894)	$ (1.00)	/Mcf	$ (3,500)	$ (0.20)	/Mcf
Liquids – change in fair value	(6,245)	$ (7.40)	/Bbl	(1,436)	$ (2.13)	/Bbl
Total unrealized gain (loss) – non-cash(1)	$ (30,139)	$ (6.23)	/Boe	$ (4,936)	$ (1.36)	/Boe

	Three Months to Dec. 31, 2016			Three Months to Dec. 31, 2015		
Realized gain (loss)						
Natural gas	$ (2,119)	$ (0.35)	/Mcf	$ 4,144	$ 0.85	/Mcf
Liquids	345	$ 1.64	/Bbl	-	$ -	/Bbl
Total realized gain (loss) – cash(1)	$ (1,774)	$ (1.45)	/Boe	$ 4,144	$ 4.20	/Boe

	Three Months to Dec. 31, 2016			Three Months to Dec. 31, 2015		
Unrealized gain (loss)						
Natural gas – change in fair value	$ (11,192)	$ (1.84)	/Mcf	$ 763	$ 0.16	/Mcf
Liquids – change in fair value	(2,733)	$ (12.97)	/Bbl	1,289	$ 7.49	/Bbl
Total unrealized gain (loss) – non-cash(1)	$ (13,925)	$ (11.36)	/Boe	$ 2,052	$ 2.08	/Boe

(1) The terms cash and non-cash are non-GAAP references.

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 – May 2017	8,000 GJ	AECO Cdn$2.81/GJ
Jan – Jun 2017	14,000 GJ	AECO Cdn$2.62/GJ
Jul – Dec 2017	13,500 GJ	AECO Cdn$2.88/GJ
Jan – Dec 2017	17,000 GJ	AECO Cdn$2.56/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – May 2017	10,400 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	7,800 Mmbtu	Chicago Cdn$4.15/Mmbtu
Jan – Jun 2018	15,850 Mmbtu	Chicago Cdn$4.11/Mmbtu
Jan – Dec 2018	3,000 Mmbtu	Chicago Cdn$3.70/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2017	7,745 GJ	Price at Stn 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Jul – Dec 2017	100 Bbls	$64.00 - $71.75 Cdn$/Bbl
Jan – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
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	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Jan – Jun 2017	200 Bbls	$67.28 Cdn$/Bbl
Jan – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	100 Bbls	$72.20 Cdn$/Bbl
Jan – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl

The fair market value of contracts outstanding at December 31, 2016 was a net liability position of $22.2 million (December 31, 2015 – net asset of $8.0 million) and is included in current and non-current assets or current and non-current liabilities as appropriate. For the three months and year ended December 31, 2016, an unrealized mark-to-market loss of $13.9 million and $30.1 million (2015 – gain of $2.1 million and loss of $4.9 million), respectively, was recognized when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

During 2016, the Company realized gains from commodity price contracts in the amount of $4.5 million compared to gains of $15.3 million in 2015. During the fourth quarter of 2016, the Company realized losses from commodity price contracts settled in the amount of $1.8 million, compared to gains of approximately $4.1 million in the fourth quarter of 2015.

Natural gas swaps priced at the AECO or Chicago monthly index are matched by sales of equal physical volumes of natural gas.

The Company's risk management program is not based on a speculative assessment of the direction of commodity prices. The program's purpose is to reduce the effect of commodity price volatility on funds flow to enable the Company to maintain a disciplined and sustainable development program. This is of particular importance at Umbach, where exploitation of the resource is at an early stage and capital investment programs necessary to delineate the scope and scale of a potentially decades-long project have to be insulated from the effects of near-term price movements.

Royalties

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 1,217	$ (54)	$ 3,823	$ 2,982
Percentage of revenue from product sales	4.6%	(0.4%)	4.9%	4.4%
Per Boe	$ 0.99	$ (0.05)	$ 0.79	$ 0.82

Total royalties in 2016 increased by 28% when compared to 2015. Royalties increased due to a decrease in infrastructure royalty credits received in 2016 compared to 2015 and higher production revenue driven by an increase in production volumes. These increases were partially offset by an increase in wells eligible for the Deep Well Royalty Credit Program, which reduces the royalty rate on eligible wells from 13% to 6% for approximately two years. The timing of receipt of infrastructure royalty credits plays a role in quarterly comparisons with $1.0 million of infrastructure royalty credits received in each of the first and fourth quarters of 2015 while $0.5 million of infrastructure royalty credits were received in the second quarter of 2016 followed by another $0.7 million in the fourth quarter of 2016. Excluding royalty credits, higher production revenue in the fourth quarter of 2016 from a combination of both increased production volumes and stronger pricing was the main driver of the higher royalties relative to the fourth quarter of 2015.

As part of British Columbia's Infrastructure Royalty Credit Program, since 2012 Storm has received approval for $14.1 million of royalty credits for various infrastructure projects. Storm recognized credits of $0.8 million in 2013, $2.0 million in 2014, $2.0 million in 2015 and $1.2 million in 2016. Remaining credits of $8.1 million will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and production levels and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially.

In 2014, the British Columbia provincial government announced the expansion of the Deep Well Royalty Credit Program by extending royalty credits to all horizontal wells. Hitherto, wells with a vertical depth of less than 1,900 metres were not eligible for the program. Horizontal wells at Umbach, drilled after April 1, 2014, will receive a royalty credit of $0.5 million to $0.8 million per well, depending on the total measured vertical depth of the well. Wells that are eligible for this expanded credit program will bear a minimum royalty at a rate of 6%. Again, the timing of receipt of royalty credits under the program cannot be readily predicted. Correspondingly, the royalty rate reported in future quarters may vary considerably.

No accounting recognition has been given to future benefits potentially accruing to Storm from either the Infrastructure Royalty Credit or the Deep Well Royalty Credit programs.

Royalties payable in Alberta are not material to the Company's operations.

Production Costs

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 8,518	$ 6,920	$ 32,794	$ 29,076
Percentage of revenue from product sales	32.5%	47.8%	42.4%	42.8%
Per Boe	$ 6.95	$ 7.01	$ 6.78	$ 8.00

Total production costs for the fourth quarter increased by 23% when compared to the same period of 2015, in line with the quarter-over-quarter production increase of 24%. On an annual basis the increase in production costs of 13% was considerably less than the production increase of 33%. Subject to seasonal variability, per-Boe charges continue to decline and are expected to fall another 15-20% from 2016 levels with the commencement of the additional processing agreement with Spectra on January 1, 2017.

Production costs for the fourth quarter of 2016 averaged $6.95 per Boe, a year-over-year reduction of 1%. Production costs per Boe for the third quarter of 2016 amounted to $6.69 per Boe. The small increase in production costs per Boe in the final quarter of 2016 was largely due to costs associated with pipeline outages. When comparing 2016 to 2015, annual production costs per Boe decreased by 15%.

Year-over-year production growth resulted in the fixed cost component of production costs per Boe falling. In addition, lower service costs contributed to the decline in per-unit production costs as did the sale of higher cost properties in Alberta in mid-2015. As previously mentioned, lower gas processing fees commencing in January 2017 should result in further reductions in per-Boe production costs.

Transportation Costs

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 673	$ 783	$ 2,186	$ 4,118
Percentage of revenue from product sales	2.6%	5.4%	2.8%	6.1%
Per Boe	$ 0.55	$ 0.79	$ 0.45	$ 1.13

Transportation costs include pipeline tariffs for natural gas, as well as trucking costs for condensate. Total transportation costs for 2016 decreased by 47% over 2015, and by 60% per Boe. Transportation costs for the fourth quarter of 2016 decreased by 14% over the same quarter of 2015 while per-Boe transportation costs declined 30%. The year-over-year cost reduction reflects natural gas marketing arrangements entered into in late 2015, lower condensate and NGL trucking costs, and the sale of Alberta oil properties in mid-2015. As the sales point for natural gas shipped on the Alliance Pipeline is the gas processing facility in British Columbia, the sales price 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.

Field Operating Netbacks

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

					Year Ended December 31, 2016
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/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 gains on commodity price contracts	0.05	6.80	-	-	0.93
Field operating netback including hedging	$ 0.64	$ 48.59	$ 11.26	$ -	$ 8.88

					Year Ended December 31, 2015
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.39	$ 50.78	$ 14.30	$ 50.84	$ 18.64
Royalties	0.02	(6.34)	(3.23)	(2.45)	(0.82)
Production costs	(1.57)	-	-	(18.22)	(8.00)
Transportation costs	(0.14)	(3.63)	-	(4.63)	(1.13)
Field operating netback	$ 0.70	$ 40.81	$ 11.07	$ 25.54	$ 8.69
Realized gains on commodity price contracts	0.57	14.12	-	-	4.20
Field operating netback including hedging	$ 1.27	$ 54.93	$ 11.07	$ 25.54	$ 12.89

					Three Months Ended December 31, 2016
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/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 gains (losses) on commodity price contracts	(0.35)	2.72	-	-	(1.45)
Field operating netback including hedging	$ 1.01	$ 50.98	$ 16.61	$ -	$ 11.48

	Three Months Ended December 31, 2015				
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 1.78	$ 47.90	$ 14.21	$ -	$ 14.67
Royalties	0.15	(5.58)	(1.74)	-	0.05
Production costs	(1.42)	-	-	-	(7.01)
Transportation costs	(0.10)	(2.90)	-	-	(0.79)
Field operating netback	$ 0.41	$ 39.42	$ 12.47	$ -	$ 6.92
Realized gains on commodity price contracts	0.85	-	-	-	4.20
Field operating netback including hedging	$ 1.26	$ 39.42	$ 12.47	$ -	$ 11.12

(1) Production costs of condensate and natural gas liquids are included with natural gas costs.
(2) Realized gains on crude oil contracts are included in total operating income per commodity unit for condensate.

Excluding realized gains and losses on commodity price contracts, field operating netback fell by 9% in 2016 compared to 2015, but increased by 87% and by 44% when compared to the fourth quarter of 2015 and the third quarter of 2016. Without question, the driving force behind the aforementioned swings in the annual and fourth quarter field operating netback was price movement, with a dismal first half of the year driving down the annual price while the fourth quarter of 2016 benefitted from strong price recovery.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, amounted to $8.56 for 2016 and $10.13 for 2015, a reduction of 15%, and $8.64 for the final quarter of 2016 compared to $8.82 for the final quarter of 2015, a reduction of 2%. Transportation costs are excluded as the sales price on part of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago under arrangements which became effective late in 2015, and thus affects comparability between 2016 and 2015. Comparing 2016 to 2015, production and general and administrative costs decreased while interest costs increased. Lower gas processing fees commencing in January 2017 should result in future reductions in cash costs per commodity unit.

General and Administrative Costs

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period – before recoveries	$ 1,755	$ 1,675	$ 6,520	$ 7,622
Overhead recoveries	(589)	(420)	(1,183)	(2,121)
Charge for period – net of recoveries	$ 1,166	$ 1,255	$ 5,337	$ 5,501
Per Boe	$ 0.95	$ 1.27	$ 1.10	$ 1.51

General and administrative costs before recoveries for 2016 decreased by 14% when compared to 2015 and for the fourth quarter of 2016 increased by 5% when compared to the same period in 2015. The year-over-year decrease is largely attributable to lower bonus payouts and lower personnel 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 27% in 2016 compared to 2015 and by 25% in the fourth quarter of 2016 compared to the same period in 2015. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Share-Based Compensation

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 808	$ 878	$ 3,124	$ 3,467
Per Boe	$ 0.66	$ 0.89	$ 0.65	$ 0.95

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 decreased by 10% in 2016 compared to 2015 and by 8% in the fourth quarter of 2016 compared to the same quarter in 2015. The year-over-year decrease in share-based compensation is primarily attributable to the 2013 stock option grant being fully expensed in early 2016.

Depletion and Depreciation

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Depletion	$ 8,643	$ 7,199	$ 34,450	$ 30,033
Depreciation	1,333	1,108	5,060	4,550
Charge for period	$ 9,976	$ 8,307	$ 39,510	$ 34,583
Per Boe	$ 8.14	$ 8.42	$ 8.17	$ 9.52

Property and equipment is subject to depletion and depreciation charges. Depletion is calculated using unit-of-production methodology under which drilling and completion costs plus future development costs associated with individual cash generating units are depleted using a factor calculated by dividing production for each reporting period by proved plus probable reserves at the beginning of the period.

The charge for depreciation for the period relates to facility and equipment costs and office equipment included with property and equipment costs. Such costs are depreciated over the useful life of the asset on a straight line basis.

The 33% increase in production volumes resulted in the total charge for depletion and depreciation increasing by 14% in 2016 compared to 2015. For the three month period, production volumes grew by 24% year over year with the depletion and depreciation charge growing by 20%. The disproportionately low increase in the year-over-year depletion and depreciation charge corresponds to low finding and development costs at Umbach as well as the sale of higher cost Alberta properties in mid-2015. Increased depreciation charges year over year corresponds to increased investment in facilities.

Exploration and Evaluation Costs Expensed

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 41	$ -	$ 41	$ 154
Per Boe	$ 0.03	$ -	$ 0.01	$ 0.04

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, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 83	$ 87	$ 347	$ 441
Per Boe	$ 0.07	$ 0.09	$ 0.07	$ 0.12

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The reduced charge for accretion in 2016 compared to 2015 is due to changes in rate estimates over the course of the year, including changes to inflation rates, discount rates and estimated settlement dates. The changes in the aforementioned rate estimates also resulted in a slightly lower accretion charge in the fourth quarter of 2016 relative to the fourth quarter of 2015.

Interest and Finance Costs

(000's)	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Charge for period	$ 910	$ 537	$ 3,268	$ 2,264
Percentage of revenue from product sales	3.5%	3.7%	4.2%	3.3%
Per Boe	$ 0.74	$ 0.54	$ 0.68	$ 0.62

Compared to the equivalent periods in the prior year, interest and finance costs in 2016 increased by 44% annually and 70% quarterly, driven by additional bank borrowings used to fund development of the Company's Umbach property. For context, the Company's bank borrowings increased 38% year over year, with borrowings ramping up in the fourth quarter to fund the Company's third field compression facility.

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.

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 discounted future cash flows of proved plus probable reserves using forecast prices and costs to estimate future value less costs of disposal. 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, 2016. Based on this review the Company determined that there were no indicators of impairment largely because of an improvement in current and forward commodity prices.

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.

Gain (Loss) on Sale of Oil and Gas Properties

In the third quarter of 2016, minor properties in Alberta were sold for proceeds of $0.6 million with a corresponding gain of $0.4 million recorded on the consolidated statement of income (loss).

Early in the third quarter of 2015, the Company sold its Grande Prairie properties which included all of the Company's crude oil properties for net proceeds of $23.6 million. The resulting loss on disposition of $1.7 million was recorded on the consolidated statement of income (loss).

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, 2016	Maximum Annual Deduction
Canadian oil and gas property expense	$ 42,000	10%
Canadian development expense	105,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	83,000	20% – 100%
Operating losses	207,000	100%
Other	3,000	20% – 100%
Total	$ 462,000	

Net Income (Loss)

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Net income (loss)	$ (12,898)	$ 1,850	$ (38,460)	$ (6,867)
Per basic and diluted share	$ (0.11)	$ 0.02	$ (0.32)	$ (0.06)

The effect of the mark-to-market valuation of commodity price contracts was significant in terms of the net loss for both the year and quarter ended December 31, 2016 as commodity prices posted considerable gains in the month of December. For 2016, the unrealized loss on commodity price contracts amounted to $30.1 million compared to the 2015 loss of $4.9 million. Similarly, for the fourth quarter of 2016 an unrealized loss on commodity price contracts of $13.9 million was recorded versus a gain for same period in 2015 of $2.1 million.

On the per-share loss of $0.32 for 2016, $0.25 represented the unrealized loss on commodity price contracts.

The unrealized gain (loss) on commodity price contracts is a non-cash charge resulting from the year-over-year and quarter-over-quarter change in the fair value of commodity price contracts outstanding at the end of the reporting period. The change in fair value recognizes the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period and also removes the opening value of contracts which have come to term during the reporting period.

Funds Flow

	Three Months to Dec. 31, 2016		Three Months to Dec. 31, 2015		Year Ended Dec. 31, 2016		Year Ended Dec. 31, 2015	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$11,985	$0.10	$ 9,182	$0.08	$34,380	$0.29	$39,046	$0.34

The Company uses funds flow, a measure that is not defined under IFRS. Funds flow 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.

Funds flow for 2016 decreased by 12% from the prior year and increased by 31% when comparing the fourth quarters of 2016 and 2015. On an annual basis, production growth was insufficient to overcome the commodity price rout, particularly in the first half of the year. For the fourth quarter, funds flow benefitted from both production growth and stronger pricing relative to the same period in 2015, partially offset by a decrease in realized gains on commodity price contracts.

Corporate Netbacks

($/Boe)	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Revenue from product sales	21.42	14.67	15.97	18.64
Realized gains (losses) on commodity price contracts	(1.45)	4.20	0.93	4.20
Royalties	(0.99)	0.05	(0.79)	(0.82)
Production	(6.95)	(7.01)	(6.78)	(8.00)
Transportation	(0.55)	(0.79)	(0.45)	(1.13)
General and administrative	(0.95)	(1.27)	(1.10)	(1.51)
Interest and finance costs	(0.74)	(0.54)	(0.68)	(0.62)
Funds flow	9.79	9.31	7.10	10.76
Share-based compensation	(0.66)	(0.89)	(0.65)	(0.95)
Depletion, depreciation and accretion	(8.21)	(8.51)	(8.24)	(9.64)
Exploration and evaluation costs expensed	(0.03)	-	(0.01)	(0.04)
Unrealized revaluation loss on investments	(0.04)	(0.03)	(0.02)	(0.16)
Gain (loss) on sale of oil and gas properties	-	(0.08)	0.09	(0.48)
Unrealized gain (loss) on commodity price contracts	(11.36)	2.08	(6.23)	(1.36)
Net income (loss) per Boe	(10.51)	1.88	(7.96)	(1.87)

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the beginning of 2015, Storm's bank facility amounted to $130.0 million. In April 2015, the facility was increased to $150.0 million in recognition of production and reserve growth at Umbach. In July 2015, subsequent to the disposal of non-core assets in Alberta, the facility was reduced to $140.0 million. In May 2016 the facility was further reduced to $130.0 million, in response to a commodity price driven lower lending value. Of this amount, 61% was drawn at December 31, 2016. The facility is available until April 28, 2017 at which time the borrowing base amount will be reviewed using current and independently prepared reserve information. In the ordinary course of business, the

Company has the option to extend 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 facility is syndicated with three banks.

At December 31, 2016, the Company is in compliance with all covenants under the credit facility, the sole financial covenant being that debt including working capital (deficiency) cannot exceed the facility credit limit. At December 31, 2016 debt including working capital (deficiency) amounted to $89.8 million.

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 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 reports to the Board at least four times a year.

Capital Expenditures

During 2016, the Company spent $65.5 million (2015 - $95.1 million) on field operations, primarily on drilling and completing wells at Umbach and constructing a third field compression facility. Twelve 100% working interest horizontal wells were drilled, ten horizontal wells were completed, and nine horizontal wells were brought on production. At December 31, 2016 there were three completed wells awaiting tie-in and six wells awaiting completion.

Major field capital outlays in 2016 include $40.9 million on drilling and completions, $18.8 million on facilities and $4.2 million on equipping and pipelines, all in the Umbach area. The facility expenditures primarily relate to the third field compression facility with approximately 60% of total costs being incurred in the fourth quarter. The facility was commissioned in January 2017 adding processing capacity of 35 Mmcf/d raw gas.

In the fourth quarter of 2016, the Company drilled five 100% interest horizontal wells; five horizontal wells were completed and three horizontal wells were brought on production.

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Land and lease	$ 240	$ 235	$ 1,413	$ 956
Land acquisitions	-	4,381	-	4,414
Drilling	11,000	7,954	22,419	20,946
Completions	8,771	14,478	18,465	31,562
Facilities	11,576	2,083	18,838	24,622
Equipping and pipelines	1,776	1,875	4,218	11,442
Recompletions and workovers	7	(45)	141	1,093
Property acquisition, adjustments, and administrative assets	29	37	44	64
Total expenditures	$ 33,399	$ 30,998	$ 65,538	$ 95,099
Proceeds on disposition of oil and gas properties	-	83	(600)	(23,590)
Net capital expenditures	$ 33,399	$ 31,081	$ 64,938	$ 71,509

Net capital investment was allocated as follows:

	Three Months to Dec. 31, 2016	Three Months to Dec. 31, 2015	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Exploration and evaluation	$ 240	$ 4,616	$ 921	$ 3,451
Property and equipment	33,159	26,465	64,017	68,058
Total capital expenditures	$ 33,399	$ 31,081	$ 64,938	$ 71,509

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, 2016 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, 2016 was $28.3 million (December 31, 2015 - $25.6 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, (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.20% (December 31, 2015 – 2.25%). 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. It also has regard 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, 2016 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
Total at December 31, 2016		120,764	$ 3.27	$ 394,474

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

In June 2015, the Company issued 8,000,000 common shares pursuant to a bought deal financing at a price of $4.55 per common share for gross proceeds of $36,400,000. This financing closed on June 10, 2015. Net proceeds received totaled $34.3 million.

During 2015, stock options were exercised at an average price of $1.81 per optioned share and 145,000 common shares were issued for proceeds of $262,000. 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.

Issued and outstanding common shares at December 31, 2016 totaled 120,763,812 and at March 2, 2017, 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 commencing 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, 2016 the remaining office lease commitment is $1.6 million. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $371.7 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended December 31, 2016 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 from the fourth quarter of 2015 to mid-way through the third quarter of 2016 have been affected by one dominant trend – production growth was insufficient to offset the relentless fall in commodity prices. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to increase production and to implement a larger capital program. As such, there was a significant increase in capital spending in the fourth quarter of 2016, while funds flow was strong, far outpacing that achieved in any of the prior quarters of 2016.

				2016				2015
($000s unless otherwise stated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue from product sales	26,244	21,047	13,870	16,121	14,480	16,283	18,461	18,512
Funds flow	11,985	8,759	5,781	7,855	9,182	7,982	8,170	13,712
Per share - basic ($)	0.10	0.07	0.05	0.07	0.08	0.07	0.07	0.12
Per share - diluted ($)	0.10	0.07	0.05	0.07	0.08	0.07	0.07	0.12
Net income (loss)	(12,898)	(85)	(20,493)	(4,984)	1,850	(961)	(4,191)	(3,565)
Per share - basic ($)	(0.11)	(0.00)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)
Per share - diluted ($)	(0.11)	(0.00)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)
Net capital expenditures	33,399	6,980	613	23,946	31,081	(4,116)(2)	8,864	35,680
Average daily production (Boe)	13,320	13,285	12,852	13,418	10,730	9,654	9,657	9,776
Debt including working capital deficiency(1)	89,841	69,303	71,254	77,162	61,721	39,994	28,051	85,098

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.
(2) Net of property disposition for proceeds of $23.6 million.

SELECTED ANNUAL FINANCIAL INFORMATION

($000s unless otherwise stated)	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenue from product sales	77,283	67,736	95,480
Funds flow	34,380	39,046	45,412
Per share – basic ($)	0.29	0.34	0.42
Per share – diluted ($)	0.29	0.34	0.41
Net income (loss)	(38,460)	(6,867)	4,855
Per share – basic ($)	(0.32)	(0.06)	0.04
Per share – diluted ($)	(0.32)	(0.06)	0.04
Total assets	465,617	440,658	418,568
Debt including working capital deficiency[1]	89,841	61,721	63,080
Average daily production (Boe)	13,219	9,956	6,980
Funds flow ($/Boe)	7.10	10.76	17.83

(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 a prolonged period of low commodity prices. This is evidenced by the downward trend in funds flow over the three year period. 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 $30.1 million unrealized loss on commodity price contracts for the year ended December 31, 2016, an unrealized loss on commodity price contracts of $4.9 million for the year ended December 31, 2015 and an unrealized gain on commodity price contracts of $14.2 million for the year ended December 31, 2014.

The increase in the Company's total assets reflects the ongoing development of the Company's Montney play at Umbach. While debt including working capital deficiency remained relatively flat in 2014 and 2015, the increase in 2016 reflects capital expenditures exceeding funds flow. The most significant driver of the increase in 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, subject to commodity prices, will result in a considerable increase in production in 2017 and beyond.

Share Trading

Set out below is share trading activity for Storm for 2016 and 2015.

					2016					2015
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	3.97	4.45	5.20	5.66	5.66	5.08	5.05	4.89	4.66	5.08
Low ($)	3.00	3.22	3.71	4.44	3.00	3.02	4.10	3.25	2.86	2.86
Close ($)	3.46	4.05	4.85	5.30	5.30	4.60	4.75	4.22	3.62	3.62
Volume traded (000s)	13,227	7,008	10,421	12,924	43,581	14,911	11,913	12,827	8,080	47,731
Value traded ($000s)	44,759	26,293	44,807	66,177	182,036	61,281	55,530	52,877	30,544	200,232
Weighted average trading price ($)	3.38	3.75	4.30	5.12	4.18	4.11	4.66	4.12	3.78	4.20

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, 2016 and 2015 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 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, particularly with respect to 2017 guidance under the heading "Outlook", 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;
- future production volumes in the fourth quarter of 2017 as well as annual production for both 2017 and 2018, 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 2017 guidance;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2017 capital program;
- future drilling, completion and tie-in of wells along with the associated costs on a per-well basis;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital programs and future availability of such sources;
- future availability of 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 Umbach and HRB 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;
- 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;
- 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 2017 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and natural gas liquids, specifically a reduction of production costs as a result of the Spectra agreement effective January 1, 2017;
- 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”; “Realized and Unrealized Gains (Losses) on Commodity Price Contracts”; “Royalties”; “Production Costs”; “Transportation Costs”; “Field Netbacks”; “General and Administrative Costs”; “Share-Based Compensation”; “Depletion and Depreciation”; “Exploration and Evaluation Costs Expensed”; “Accretion”; “Interest and Finance Costs”; “Unrealized Revaluation Loss on Investment”; Reduction of Carrying Amount of Property and Equipment”; “Gain (Loss) on Disposal of Oil and Gas Properties”; “Income Taxes”; “Net Income (Loss)”; “Funds Flow”; “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 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 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 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”, “cash costs”, the terms “cash” and “non-cash”, 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.

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 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.

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. 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.

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 has reduced field activity and thus concerns over access to equipment and services. Further, service costs have fallen in recent quarters. 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 quarter of 2015 for a period of 28 days. It is expected that this facility will again be closed for maintenance for a period of 21 days in the second quarter of 2017.

Storm's contracted gas processing capacity at third party facilities was approximately 80% of total raw gas production during December 2016 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.
- 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 72 Mmcf per day of natural gas sales volumes in the first quarter of 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 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 the United States. When, if ever, access to historical markets in the United States 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.

Political Risk

In both Canada and the United States the energy industry is subject to scrutiny, frequently hostile, by political and environmental groups. In particular, horizontal drilling and hydraulic fracturing procedures have been subject to criticism, largely on environmental grounds. This may lead to increased regulation and increased compliance costs. In addition, the strained financial circumstances of the provincial governments of both Alberta and British Columbia, may lead to the termination or amendment of existing royalty incentive programs, or increases in royalty and income tax rates. The same concern applies to the Federal government. Federal corporate tax rates are low by international standards and are thus vulnerable to upward adjustment. Further, the recent election of an avowedly protectionist government in 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.

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, 2016.

Future Accounting Policy Changes

In May 2014, the IASB issued 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. Upon initial assessment of the Company's significant revenue contracts, the adoption of IFRS 15 may result in presentation changes in revenue which are not expected to affect net income/(loss).

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. 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. Upon initial assessment, the Company does not expect that the adoption of IFRS 9 will have a material effect on the Company.

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 evaluating the effect of this standard.

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 adopted by the Chartered Professional Accountants of Canada ("CPA Canada"). 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.

Donald McLean
Chief Financial Officer

John Devlin
Vice President, Finance

March 2, 2017

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, 2016 and 2015, 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, 2016 and 2015, 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 2, 2017

Consolidated Statements of Financial Position

(Canadian $000s)	December 31, 2016	December 31, 2015
ASSETS		
Current		
Accounts receivable (Note 14)	$ 13,199	$ 9,635
Prepaids and deposits	1,176	728
Fair value of commodity price contracts (Note 14)	483	7,984
	14,858	18,347
Exploration and evaluation (Note 6)	110,395	119,356
Property and equipment (Note 7)	340,364	302,955
	$ 465,617	$ 440,658
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 25,382	$ 15,007
Fair value of commodity price contracts (Note 14)	20,622	-
	46,004	15,007
Bank indebtedness (Note 8)	78,834	57,077
Fair value of commodity price contracts (Note 14)	2,016	-
Decommissioning liability (Note 9)	18,983	16,016
	145,837	88,100
Shareholders' equity		
Share capital (Note 11)	389,316	385,766
Contributed surplus (Note 12)	8,870	6,738
Deficit	(78,406)	(39,946)
	319,780	352,558
Commitments (Note 18)		
	$ 465,617	$ 440,658

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, 2016	Year Ended December 31, 2015
Revenue		
Revenue from product sales	$ 77,283	$ 67,736
Royalties	(3,823)	(2,982)
Net revenue	$ 73,460	$ 64,754
Realized gain on commodity price contracts (Note 14)	4,505	15,251
Unrealized loss on commodity price contracts (Note 14)	(30,139)	(4,936)
Income (loss) on commodity price contracts	$ (25,634)	$ 10,315
Expenses		
Production	32,794	29,076
Transportation	2,186	4,118
General and administrative (Notes 16 and 18)	5,337	5,501
Share-based compensation (Note 12)	3,124	3,467
Depletion and depreciation (Note 7)	39,510	34,583
Exploration and evaluation costs expensed (Note 6)	41	154
Accretion (Note 9)	347	441
	83,339	77,340
Loss before the following:	(35,513)	(2,271)
Interest and finance costs	(3,268)	(2,264)
Unrealized revaluation loss on investments (Note 14)	(120)	(580)
Gain (loss) on sale of oil and gas properties (Note 7)	441	(1,752)
Net loss for the year	(38,460)	(6,867)
Other comprehensive loss		
Reversal of prior year unrealized gain on investments	-	(110)
Comprehensive loss for the year	$ (38,460)	$ (6,977)
Net loss per share (Note 13)		
- basic	$ (0.32)	$ (0.06)
- diluted	$ (0.32)	$ (0.06)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s)				Year Ended December 31, 2016	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	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

(Canadian $000s)				Year Ended December 31, 2015	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of year	$ 351,161	$ 3,363	$ (33,079)	$ 110	$ 321,555
Net loss for the year	-	-	(6,867)	-	(6,867)
Issue of common shares (Note 11)	36,662	-	-	-	36,662
Share issue costs (Note 11)	(2,149)	-	-	-	(2,149)
Share-based compensation (Note 12)	-	3,467	-	-	3,467
Share-based compensation on options exercised (Note 11)	92	(92)	-	-	-
Reversal of prior period unrealized gain on investments (Note 14)	-	-	-	(110)	(110)
Balance, end of year	$ 385,766	$ 6,738	$ (39,946)	$ -	$ 352,558

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Year Ended December 31, 2016	Year Ended December 31, 2015
Operating activities		
Net loss for the year	$ (38,460)	$ (6,867)
Non-cash items:		
Share-based compensation (Note 12)	3,124	3,467
Depletion, depreciation and accretion (Notes 7 and 9)	39,857	35,024
Exploration and evaluation costs expensed (Note 6)	41	154
Unrealized revaluation loss on investments (Note 14)	120	580
Loss (gain) on sale of oil and gas properties (Note 7)	(441)	1,752
Unrealized loss on commodity price contracts (Note 14)	30,139	4,936
Funds flow	34,380	39,046
Net change in non-cash working capital items (Note 17)	(597)	(3,579)
	33,783	35,467
Financing activities		
Proceeds from issue of common shares – net of expenses (Note 11)	2,558	34,510
Increase in bank indebtedness	21,757	11,047
	24,315	45,557
Investing activities		
Additions to exploration and evaluation assets (Note 6)	(1,402)	(5,350)
Additions to property and equipment (Note 7)	(64,136)	(89,749)
Proceeds on disposal of exploration and evaluation assets (Notes 6 and 7)	481	1,899
Proceeds on disposal of property and equipment (Note 7)	119	21,691
Net change in non-cash working capital items (Note 17)	6,840	(9,515)
	(58,098)	(81,024)
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, 2016 and 2015

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 Venture Exchange 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 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 2, 2017.

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 oil, NGL and natural gas 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.

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, crude oil and 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, crude oil and 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.

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 employees and directors. 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, 2016.

Future Accounting Policy Changes

In May 2014, the IASB issued 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. Upon initial assessment of the Company's significant revenue contracts, the adoption of IFRS 15 may result in presentation changes in revenue which are not expected to affect net income/(loss).

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. 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. Upon initial assessment, the Company does not expect that the adoption of IFRS 9 will have a material effect on the Company.

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 evaluating the effect of this standard.

5. SIGNIFICANT ACCOUNTING JUDGEMENTS, 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, income 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 period 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. Changes in forward price estimates, production and future development costs, recovery rates or decommissioning costs 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.

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, 2016	Year Ended December 31, 2015
Balance, beginning of year	$ 119,356	$ 126,805
Additions	1,402	5,350
Exploration and evaluation expenditures expensed	(41)	(154)
Future decommissioning costs	100	313
Disposals	(100)	(2,843)
Transfer to property and equipment	(10,322)	(10,115)
Balance, end of year	$ 110,395	$ 119,356

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at December 31, 2016 and 2015 and none were identified.

7. PROPERTY AND EQUIPMENT

	Year Ended December 31, 2016	Year Ended December 31, 2015
Cost		
Balance, beginning of year	$ 389,781	$ 379,207
Additions	64,136	89,749
Future decommissioning costs	2,581	1,831
Disposals	(120)	(91,121)
Transfer from exploration and evaluation assets	10,322	10,115
Balance, end of year	$ 466,700	$ 389,781
Accumulated depletion and depreciation		
Balance, beginning of year	$ (86,826)	$ (110,744)
Depletion and depreciation	(39,510)	(34,583)
Disposals	-	58,501
Balance, end of year	$ (126,336)	$ (86,826)
Net book value, beginning of year	$ 302,955	$ 268,463
Net book value, end of year	$ 340,364	$ 302,955

In July 2015, the Company sold its Grande Prairie oil properties for net proceeds of approximately $23.6 million. The resulting loss of $1.8 million was recorded on the statement of income (loss) and comprehensive income (loss).

Future development costs for the year ended December 31, 2016 of $524.0 million (December 31, 2015 - $543.3 million) were included in the depletion calculation.

Impairment Assessment and Testing

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2016, the Company determined that there were no indicators of impairment.

At December 31, 2015, the Company determined that an indicator of impairment existed for its material producing CGU at Umbach, being the continuing decline in the current and forward prices for hydrocarbons. The decline was not considered to be an indicator of impairment for the other minor CGUs whose values are more dependent on land values than commodity prices. The impairment test performed applied a pre-tax discount rate of 10% (this discount rate gives recognition to the quality, scale and repeatability of the Umbach project). The Company concluded that there was no impairment to property and equipment as at December 31, 2015 as the recoverable amount was greater than the carrying value. The recoverable amount was determined using Level 3 inputs. An increase in the discount rate to 15% would not have resulted in an impairment charge.

8. BANK INDEBTEDNESS

As at December 31, 2016, the Company had an extendible revolving bank facility in the amount of $130.0 million (December 31, 2015 – $140.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 28, 2017, 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 revolving facility is not extended, the facility moves into a term phase whereby the loan is to be retired with one payment one year later, in an amount equal to the outstanding principal. Interest is paid on the revolving 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 facility amount. At December 31, 2016, the Company is in compliance with all covenants under the credit facility.

As at December 31, 2016, the Company had issued letters of credit in the amount of $8.1 million in support of future gas transportation and processing obligations (Note 18) and future reclamation liabilities. As at March 2, 2017, the date of this report, letters of credit in the amount of $8.4 million had been issued. Availability under the Company's bank 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 obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning obligation is approximately $28.3 million (December 31, 2015 - $25.6 million), which is expected to be paid over the next 30 years with the majority of payments being made in the years 2034 to 2047. A risk-free discount rate of 2.20% (2015 – 2.25%) and an inflation rate of 1.6% (2015 – 1.9%) was used to calculate the present value of the decommissioning obligation, amounting to $19.0 million.

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Balance, beginning of year	$ 16,016	$ 23,553
Obligations incurred	3,159	1,961
Obligations disposed	(61)	(10,122)
Change in rate estimates[(1)]	(478)	(68)
Change in cost estimates	-	251
Accretion expense	347	441
Balance, end of year	$ 18,983	$ 16,016

(1) Relates to changes in inflation rates, 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 $255.0 million as well as non-capital losses of approximately $207.0 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, 2016	Year Ended December 31, 2015
Net loss for the year	$ (38,460)	$ (6,867)
Statutory combined federal and provincial income tax rate	26.4%	26.5%
Expected income tax expense (recovery)	$ (10,153)	$ (1,820)
Add (deduct) the income tax effect of:		
Share-based compensation	825	919
Change in unrecorded deferred income tax asset	9,395	1,264
Change in enacted corporate tax rate	-	(178)
Change in estimated tax pool balances	(86)	(98)
Other	19	(87)
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, 2016	As at December 31, 2015
Deferred tax assets:		
Non-capital losses	$ 55,007	$ 45,474
Decommissioning liability	5,011	4,244
Fair value of commodity price contracts	5,849	-
Share issue costs	712	1,137
Investment	246	231
	$ 66,825	$ 51,086
Deferred tax liabilities:		
Property and equipment in excess of tax basis	$ (43,131)	$ (34,267)
Fair value of commodity price contracts	-	(2,116)
	$ (43,131)	$ (36,383)

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, 2014	111,322	$ 351,161
Shares issued pursuant to private placement(1)	8,000	36,400
Share issue costs(1)	-	(2,149)
Shares issued on stock option exercises (2)	145	354
Balance as at December 31, 2015	119,467	$ 385,766
Shares issued on stock option exercises (3)	1,297	3,550
Balance as at December 31, 2016	120,764	$ 389,316

(1) On June 10, 2015 the Company issued 8,000,000 common shares, pursuant to a bought deal financing, at a price of $4.55 per common share for gross proceeds of $36,400,000 before issue costs of approximately $2.1 million.

(2) During 2015, 145,000 common shares were issued upon the exercise of stock options for proceeds of $262,000 and related prior period share-based compensation of $92,000 was transferred to share capital from contributed surplus.

(3) 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.

(4) From the period from January 1 to March 2, 2017, 793,000 common shares were issued upon the exercise of stock options for proceeds of $1,455,000.

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, 2016, a total of 12,076,381 common shares were available for issuance. Options in respect of 12,039,500 common shares have been issued, of which 3,652,500 have been exercised or cancelled at December 31, 2016. Options in respect of 8,387,000 common shares were issued and outstanding at December 31, 2016.

At March 2, 2017, 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 7,739,000 common shares were issued and outstanding and 4,416,681 are available for future issue.

Details of the options outstanding at December 31, 2016 and December 31, 2015 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2014	5,957	$ 3.54
Granted during the year	1,941	$ 3.38
Exercised during the year	(145)	$ 1.81
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
Number exercisable at December 31, 2016	3,864	$ 3.78

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
$1.75 - $2.63	770	0.1	$ 1.75	770	$ 1.75
$2.64 - $3.95	1,851	2.9	$ 3.35	617	$ 3.35
$3.96 - $5.50	5,766	2.4	$ 4.82	2,477	$ 4.51
Total	8,387	2.3	$ 4.21	3,864	$ 3.78

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, 2016 of $2.11 per share (2015 - $1.33 per share) include the following:

	2016	2015
Share price	$4.90 - $5.50	$3.35 - $4.71
Exercise price	$4.90 - $5.50	$3.35 - $4.71
Volatility	52%	53%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Risk-free interest rate	0.6% - 0.9%	0.4% - 0.7%

Share-based compensation expense of $3.1 million was charged to the consolidated statement of income (loss) during the year ended December 31, 2016 (2015 - $3.5 million) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company’s share price using market data.

13. NET LOSS PER SHARE

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Net loss for the year	$ (38,460)	$ (6,867)
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	119,467	111,322
Effect of shares issued	586	4,499
Weighted average number of common shares outstanding – basic	120,053	115,821
Effect of outstanding options	-	-
Weighted average number of common shares outstanding - diluted	120,053	115,821
Net loss per share		
- basic	$ (0.32)	$ (0.06)
- diluted	$ (0.32)	$ (0.06)

At December 31, 2016, all outstanding stock options were considered anti-dilutive as the Company was in a loss position.

14. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, prepaids and 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 year ended December 31, 2016.

For the years ended December 31, 2016 and December 31, 2015, 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 25^{th} 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, 2016, the Company's most significant marketer accounted for $8.0 million (2015 - $4.0 million) of total receivables and 64% of total annual revenues (2015 – 63%). 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, 2016 and December 31, 2015, 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, 2016.

The maximum exposure to credit risk at December 31, 2016 was the carrying amount of accounts receivable of $13.2 million and commodity price contract assets of $0.5 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, 2016, 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 is a net liability position of $22.2 million (December 31, 2015 – net asset of $8.0 million) is included in current and non-current assets or current and non-current liabilities as appropriate. For the year ended December 31, 2016, this resulted in an unrealized mark-to-market loss of $30.1 million (2015 – loss of $4.9 million) 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).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jan – May 2017	8,000 GJ	AECO Cdn$2.81/GJ
Jan – Jun 2017	14,000 GJ	AECO Cdn$2.62/GJ
Jul – Dec 2017	13,500 GJ	AECO Cdn$2.88/GJ
Jan – Dec 2017	17,000 GJ	AECO Cdn$2.56/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – May 2017	10,400 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	7,800 Mmbtu	Chicago Cdn$4.15/Mmbtu
Jan – Jun 2018	15,850 Mmbtu	Chicago Cdn$4.11/Mmbtu
Jan – Dec 2018	3,000 Mmbtu	Chicago Cdn$3.70/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2017	7,745 GJ	Price at Stn 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Jul – Dec 2017	100 Bbls	$64.00 - $71.75 Cdn$/Bbl
Jan – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
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	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Jan – Jun 2017	200 Bbls	$67.28 Cdn$/Bbl
Jan – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	100 Bbls	$72.20 Cdn$/Bbl
Jan – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl

During 2016, the Company realized gains from commodity price contracts in place in the amount of $4.5 million (2015 – gains of $15.3 million).

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.

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

Using the Company's actual production volumes, royalty rates and bank indebtedness for the year ended December 31, 2016, the estimated after-tax effect that changes in certain factors would have on net loss and net loss per share is set out below:

		2016
Factor	Change in Net Loss	Change in Net Loss Per Share
US$1.00/Bbl change in the price of WTI[1]	$ 1,010	$ 0.01
$0.10/Mcf change in the price of natural gas	$ 2,340	$ 0.02
1% change in the interest rate	$ 740	$ 0.01

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

The Company's income tax assets are sufficient to eliminate taxes payable on the increases to income resulting from above; accordingly, before and after tax amounts are the same.

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, 2016 is as follows:

	Less than 1 year	2-3 years	Total
Accounts payable and accrued liabilities	$ 25,382	$ -	$ 25,382
Commodity price contracts	20,622	2,016	22,638
Bank indebtedness[1]	-	78,834	78,834
Total financial liabilities	$ 46,004	$ 80,850	$ 126,854

(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

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, 2016	Year Ended December 31, 2015
Salaries and short-term benefits	$ 2,412	$ 2,465
Share-based compensation	1,680	1,370
Total	$ 4,092	$ 3,835

17. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2016	Year Ended December 31, 2015
Accounts receivable	$ (3,684)	$ (849)
Prepaids and deposits	(448)	177
Accounts payable and accrued liabilities	10,375	(12,422)
Change in non-cash working capital	$ 6,243	$ (13,094)
Relating to:		
Operating activities	$ (597)	$ (3,579)
Investing activities	6,840	(9,515)
	$ 6,243	$ (13,094)
Interest paid during the year	$ 3,001	$ 2,023
Income taxes paid during the year	$ -	$ -

18. COMMITMENTS

The Company has the following long-term commitments over the next five years and thereafter:

	2017	2018	2019	2020	2021	Thereafter	Total
Office lease	$ 923	$ 692	$ -	$ -	$ -	$ -	$ 1,615
Natural gas sales commitments	48,932	47,952	33,301	31,434	21,163	188,881	371,663
Total	$ 49,855	$ 48,644	$ 33,301	$ 31,434	$ 21,163	$188,881	$373,278

In 2016 the Company made office lease payments of approximately $930 (2015 - $928) which were included in general and administrative expense.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Donald G. McLean
Chief Financial Officer

John Devlin
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
CEO

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

TSX Venture 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

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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil 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
kPa	One thousand pascals
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbbl	Millions of barrels
Mmboe	Millions of barrels of oil equivalent
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
Mstb	Thousand stock tank barrels
NAV	Net Asset Value
NGL	Natural gas liquids (includes butane & propane)
NPV	Net present value
OGIP	Original Gas in Place
OPEC	Organization of Petroleum Exporting Countries
psig	pounds per square inch gage pressure
Scf/ton	Standard cubic foot per ton
STOOIP	Stock Tank Original Oil in Place
Tcf	Trillions of cubic feet
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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