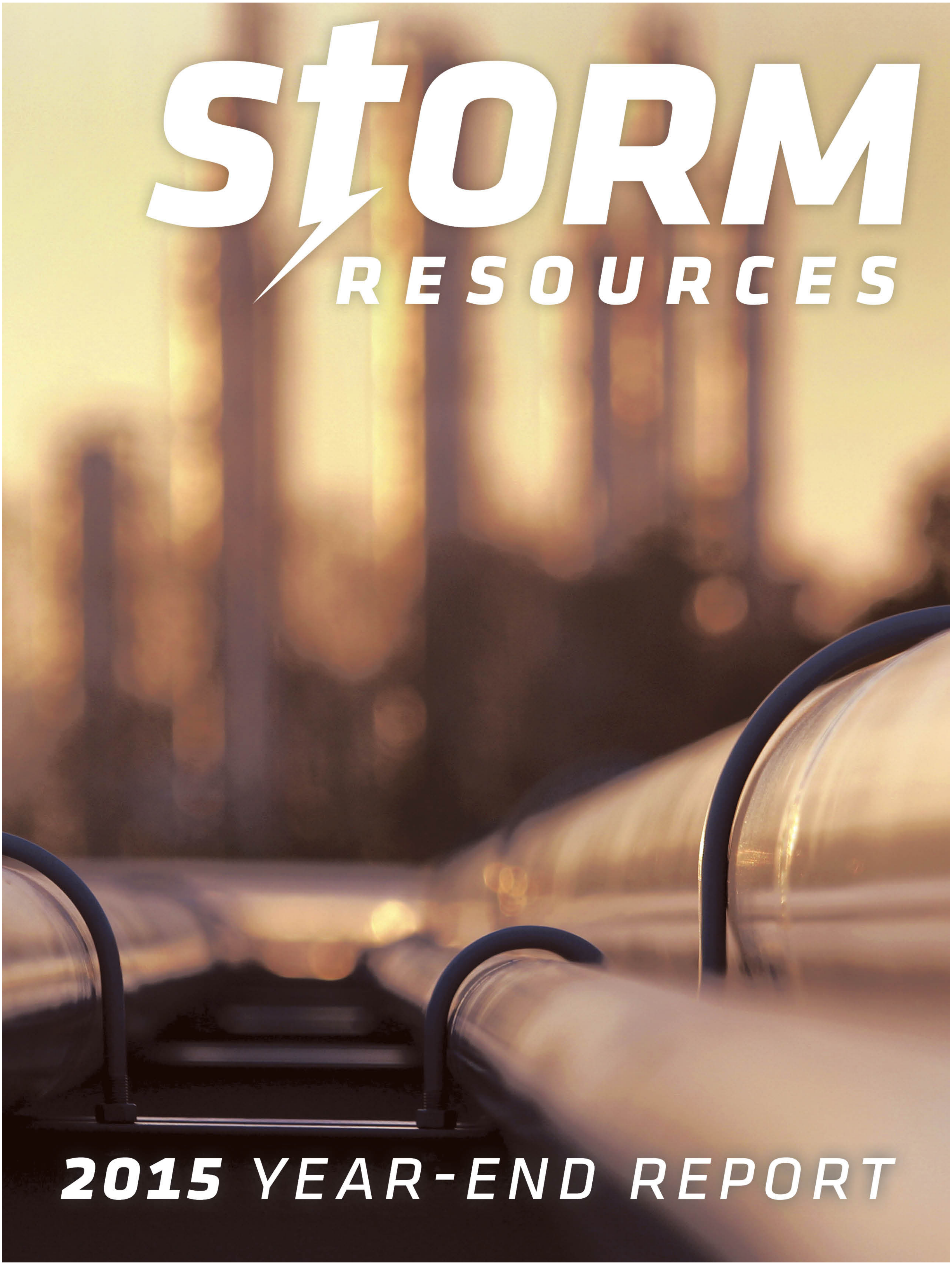

STORM
RESOURCES
2015 YEAR-END REPORT

ANNUAL MEETING

The Annual General Meeting of shareholders will be held at 11:00 a.m. on Friday, May 13, 2016 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$, except volumetric and per-share amounts	Three Months to Dec. 31, 2015	Three Months to Dec.31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
FINANCIAL				
Revenue from product sales(1)	14,480	28,070	67,736	95,480
Funds from operations(2)	9,182	13,892	39,046	45,412
Per share - basic ($)	0.08	0.13	0.34	0.42
Per share - diluted ($)	0.08	0.12	0.34	0.41
Net income (loss)	1,850	(7,422)	(6,867)	4,855
Per share - basic ($)	0.02	(0.07)	(0.06)	0.04
Per share - diluted ($)	0.02	(0.07)	(0.06)	0.04
Net capital invested	31,081	20,095	71,509	194,555
Operations capital expenditures	26,700	20,219	90,685	106,604
Land and property acquisitions/ (dispositions)	4,381	(124)	(19,176)	87,951
Debt including working capital deficiency(3)	61,721	63,080	61,721	63,080
Common shares (000s)				
Weighted average - basic	119,388	111,305	115,821	108,172
Weighted average - diluted	119,388	112,850	115,821	109,981
Outstanding end of period – basic	119,467	111,322	119,467	111,322
OPERATIONS				
(Cdn$ per Boe)				
Revenue	14.67	29.99	18.64	37.48
Royalties	0.05	(3.69)	(0.82)	(5.16)
Production	(7.01)	(8.40)	(8.00)	(9.33)
Transportation	(0.79)	(1.91)	(1.13)	(1.80)
Field operating netback	6.92	15.99	8.69	21.19
Hedging gains (losses)	4.20	0.52	4.20	(1.26)
General and administrative	(1.27)	(1.16)	(1.51)	(1.50)
Interest and finance costs	(0.54)	(0.50)	(0.62)	(0.60)
Funds from operations - per Boe	9.31	14.85	10.76	17.83
Barrels of oil equivalent per day (6:1)	10,730	10,173	9,956	6,980
Gas Production				
Thousand cubic feet per day	53,147	49,094	48,656	33,067
Price (Cdn$ per Mcf)	1.78	3.85	2.39	4.58
NGL production				
Barrels per day	1,872	1,605	1,667	1,064
Price (Cdn$ per barrel)	33.50	56.15	36.10	69.90
Oil Production				
Barrels per day	-	385	179	405
Price (Cdn$ per barrel)	-	68.01	50.84	88.10
Wells drilled				
Gross	4.0	2.0	10.0	17.0
Net	4.0	2.0	10.0	17.0

(1) Excludes hedging gains and losses.
(2) Certain financial amounts shown above are non-GAAP measurements, including funds from operations and funds from operations per share, 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 ("MD&A") and the reconciliation of funds from operations to the most directly comparable measurement under GAAP, "Cash Flows from Operating Activities", on page 29 of the attached MD&A.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2015 FOURTH QUARTER HIGHLIGHTS

- Production averaged 10,730 Boe per day (17% NGL), a per-share decrease of 2% from the previous year. During October and November, wells were shut in due to the low natural gas price at BC Station 2 (averaged $0.88 per GJ) which reduced production by approximately 2,700 Boe per day (production in December was 13,600 Boe per day).

- NGL production was 1,872 barrels per day, an increase of 17% from the previous year. The price was $33.50 per barrel which was 63% of the average Edmonton light oil price (57% of the NGL volume was higher value condensate and plant pentanes).

- On December 1, 2015, Storm began flowing gas on the Alliance Pipeline to Chicago which improved the natural gas price in December by approximately $0.45 per Mcf over the equivalent BC Station 2 price.

- Activity was focused at Umbach where four horizontal wells were drilled, six horizontal wells were completed and three horizontal wells commenced production.

- At the end of the quarter, there was an inventory of six horizontal wells (6.0 net) that had not started producing (includes two completed wells).

- Montney horizontal well performance at Umbach has continued to improve as length and the number of frac stages are increased. The three most recent wells started producing in November and December, had 22 to 24 frac stages and averaged 6.5 Mmcf per day gross raw gas (1,150 Boe per day sales) over the first 90 calendar days, a 40% improvement from the average 2014 well.

- Controllable cash costs (operating, cash G&A, interest expense) were $8.82 per Boe, a year-over-year decrease of 12%.

- Funds from operations was $9.31 per Boe, a year-over-year decrease of $5.54 per Boe. Revenue declined by $15.32 per Boe which was partially offset by a hedging gain of $4.20 per Boe, royalties decreasing by $3.74 per Boe and operating costs declining by $1.39 per Boe.

- Net income was $1.9 million or $1.88 per Boe which reflects the year-over-year improvement in capital efficiency (notable given that revenue per Boe decreased by 51%).

- Debt including working capital deficiency was $61.7 million which is 1.7 times annualized fourth quarter funds flow. Storm's bank credit facility is currently $140.0 million.

2015 YEAR END HIGHLIGHTS

- Production for the year averaged 9,956 Boe per day (19% oil plus NGL), a year-over-year increase of 43%, or 33% on a per-share basis. Wells were shut in during the second half of the year as a result of a low natural gas price at BC Station 2 which reduced production for the year by approximately 1,400 Boe per day. The yearly average was also reduced from the McMahon Gas Plant being shut in for 28 days in June for a loss of 550 Boe per day and properties in the Grande Prairie area producing 725 Boe per day were sold effective July 1, 2015.

- Controllable cash costs (operating, cash G&A, interest expense) were $10.13 per Boe, a decrease of 11% from last year.

- Funds from operations totaled $39.0 million, a year-over-year decrease of 14% which was mainly caused by revenue per Boe decreasing by 50% which exceeded production growth of 43%.

- Net capital investment was $71.5 million and included $23.6 million of proceeds from selling non-core properties in the Grande Prairie area of Alberta, $4.5 million to acquire undeveloped land at Umbach (12 net sections) and $36.0 million to expand infrastructure at Umbach.

- Infrastructure investment at Umbach included $18.5 million to increase field compression capacity to 80 Mmcf raw gas per day (from 45 Mmcf raw gas per day at the end of 2014), $5.3 million for 20 kilometers of pipeline, and $4.8 million to purchase major equipment for the third field compression facility.

- The one year FD&A cost (all-in) for reserve additions was $6.53 per Boe for PDP, $3.38 per Boe for 1P and $0.50 per Boe for 2P. The removal of reserves and associated FDC for a disposition and for economic factors reduced the 1P and 2P FD&A cost. The one year F&D excluding acquisitions, dispositions and revisions (per NI51-101) is more representative and was $7.61 per Boe for 1P and $6.47 per Boe for 2P.

- The recycle ratio using the one year FD&A cost (all-in) and the funds from operations netback was 1.6X for PDP, 3.2X for 1P and 21.5X for 2P.

- Using fourth quarter production, the reserve life index was 5.3 years for PDP, 18.8 years for 1P and 25.7 years for 2P.

- Cost of production additions in 2015 improved to $11,000 per Boe per day using total capital investment and fourth quarter production of 6,500 Boe per day from wells that started production in 2015 (last year was $29,800 per Boe per day). This is reduced to $8,500 per Boe per day when land and property acquisitions/dispositions and investment in infrastructure are excluded (approximates the cost to maintain production levels).

- Storm's enterprise value at year end plus FDC was equal to $10.29 per Boe on a 2P basis. Enterprise value was determined using the year-end closing share price of $3.62, 119.4 million shares outstanding, and after adding year-end debt including working capital deficiency.

2015 YEAR END RESERVE EVALUATION

Reserves	2015	2014	Change
Proved Developed Producing or "PDP" (Mboe)	20,810	13,487	+54%
Total Proved or "1P" (Mboe)	73,434	59,551	+23%
Total Proved plus Probable or "2P" (Mboe)	100,722	88,024	+14%
PDP as % of 2P	21%	15%	
1P as a % of 2P	73%	68%	

- PDP reserve growth of 54% was consistent with the 43% year-over-year increase in corporate production.

Reserves Per Share Outstanding at Year End	2015	2014	Change
PDP (Mboe per million shares)	174	121	+44%
1P (Mboe per million shares)	615	535	+15%
2P (Mboe per million shares)	844	791	+7%

- Reserve growth on a per share basis was reduced by an equity issue completed in May 2015.

Future Development Capital (“FDC”)	2015	2014
1P ($M)	$435,000	$448,000
2P ($M)	$543,000	$607,000

- The year-over-year decrease in FDC was the result of selling properties at Grande Prairie (2P FDC $37.4 million removed), removing three drilling locations in the HRB (2P FDC $56.6 million removed) and increasing the number of 2P future drilling locations at Umbach (2P FDC increased $30 million).

FD&A Cost (all-in)	2015	2014
PDP ($/Boe)	$6.53	$23.01
1P ($/Boe)	$3.38	$11.68
2P ($/Boe)	$0.50	$9.64

- The all-in FD&A cost reflects the result of Storm’s entire capital investment program and was significantly improved in 2015 because of positive technical revisions from well performance at Umbach exceeding expectations plus a large reduction in the value of land and property acquisitions/dispositions (net proceeds of $19.2 million realized in 2015 versus an expenditure of $88.0 million in 2014).

Recycle Ratio Using FD&A Cost (all-in)	2015	2014
Annual field operating netback excluding hedging	$8.69	$21.19
PDP Recycle	1.3X	0.9X
1P Recycle	2.6X	1.8X
2P Recycle	17.4X	2.2X

- Recycle ratios improved significantly in 2015 as a result of the decrease in the FD&A cost. The PDP recycle ratio was 1.6X using the 2015 funds from operations netback (includes cash G&A, interest expense, and hedging gains).

Net Present Value Discounted at 10% (before tax)	2015	2014	Change
PDP ($M)	$213,000	$199,000	+7%
1P ($M)	$442,000	$493,000	-10%
2P ($M)	$592,000	$684,000	-13%

- Net present values discounted at 10% were largely unchanged from last year as the price forecast for AECO natural gas used by Storm’s external reservoir engineer, InSite Petroleum Consultants Ltd. (“InSite”), decreased by 24% over the first five years. For Edmonton Par light oil, the decrease was 13%.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 109,000 net acres (155 net sections). To date, a total of 40.4 net horizontal wells (44.0 gross) have been drilled into the Montney formation with 31.4 net being on production.

Fourth quarter production from Umbach was 10,729 Boe per day and represented 100% of corporate production in the quarter. NGL recovery was 35 barrels per Mmcf sales (57% of the NGL volume is higher priced field condensate plus pentanes recovered at the gas plant). Revenue was $14.72 per Boe ($1.78 per Mcf sales and $33.50 per barrel of NGL), transportation costs were $0.79 per Boe, royalties were $0.07 per Boe (1% of revenue), operating costs were $6.91 per Boe and the operating netback was $6.95 per Boe. The natural gas sales price in December was $0.45 per Mcf higher than what was realized in October and November.

Activity in the fourth quarter included drilling four horizontal wells (4.0 net), completing six horizontal wells (6.0 net) and pipeline connecting three horizontal wells (3.0 net). At year end, there was an inventory of six horizontal wells (6.0 net) that had not started producing (includes two completed wells).

In the first quarter of 2016, seven more horizontal wells (7.0 net) will be drilled and two horizontal wells (2.0 net) will be completed.

Storm's two operated field compression facilities (both 100% working interest) have total capacity of 80 Mmcf per day raw gas with actual throughput in December averaging 73 Mmcf per day raw gas. As a result of the low natural gas price at AECO and BC Station 2, timing to start up the third field compression facility with initial capacity of 35 Mmcf per day is being moved back to the fourth quarter of 2016 (was May 2016). The estimated total cost is unchanged at $25.0 million (expandable to 70 Mmcf per day raw gas for an additional $7.0 million). During 2015, $4.8 million was invested for site preparation and to purchase major equipment for the third facility.

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where Storm has firm processing commitments totaling 65 Mmcf per day raw gas in 2016.

Shown below is a summary of horizontal well performance and costs. On a per-stage basis, the 2015 drill and complete cost decreased by 15% from 2014 with cost reductions coming from pad drilling, improved water management practices and lower service costs. Performance to date of the 2015 wells does not fully reflect the increased level of stimulation because calendar day rates were reduced by the downtime experienced in the second half of 2015. The three most recent 2015 wells with 22 to 24 frac stages averaged 6.5 Mmcf per day gross raw gas over the first 90 calendar days, an improvement of 40% from the average 2014 horizontal well.

Year of Completion	**Avg Frac Stages**	**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**
2010 - 12 7 wells	11		1.9 Mmcf/d 7 hz's	1.4 Mmcf/d 7 hz's	1.3 Mmcf/d 7 hz's
2013 6 wells	17	$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 13 wells	19	$4.6 million ($240 K/stage)	4.6 Mmcf/d 13 hz's	4.2 Mmcf/d 13 hz's	3.3 Mmcf/d 11 hz's
2015 11 wells	22	$4.5 million ($205 K/stage)	5.0 Mmcf/d 9 hz's	3.7 Mmcf/d 3 hz's	
2016 4 wells	29				

Based on the performance of the 2014 and 2015 horizontal wells, Storm management uses a 6.3 Bcf raw gas type curve for internal budgeting purposes (type curve has the same decline profile as the type curves used by InSite in the 2015 reserve evaluation). The first year average rate is 3.6 Mmcf per day raw gas which is 640 Boe per day sales (10% shrinkage and 32 barrels of NGL per Mmcf sales). Using the actual cost of $4.8 million to drill, complete and tie in a horizontal well in 2015, the payout is approximately 32 months and the rate of return is 26% based on $2.60 per GJ at AECO, $2.10 per GJ at BC Station 2 and Cdn $53.00 per barrel for Edmonton light oil (expected longer term commodity prices with pricing held flat for the life of the well). See the presentation on Storm's website for further details.

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. The one horizontal well producing 280 Boe per day was shut in during July 2015 due to the low natural gas price at BC Station 2.

Grande Prairie Area, Northwest Alberta

Storm's remaining Alberta property at Valhalla was shut in during August 2015 as a result of the decline in the natural gas price (capable of producing 300 Boe per day).

HEDGING AND TRANSPORTATION

The purpose of Storm's commodity price hedges is to provide greater certainty regarding future cash flows and capital investment in order to support longer term growth plans. A maximum of 50% of the most recent monthly production will be hedged; anticipated production growth is not hedged. Although Storm has no oil production, approximately 80% of NGL production is priced in reference to WTI (condensate, plant pentane, and butane).

A gain of $15.3 million was realized from commodity price hedging in 2015 and the fair market value of commodity price contracts for 2016 and 2017 was $8.0 million at year end.

A summary of commodity price hedges for 2016 is provided below.

	Volume	Price
Crude Oil	500 Bopd	WTI Cdn$75.00 X Cdn$90.75/Bbl
Natural Gas	21,250 GJ/d (17,000 Mcf/d)	AECO Cdn$2.98/GJ ($3.72/Mcf)
	11,000 GJ/d (8,800 Mcf/d)	BC Stn 2 price = AECO – Cdn$0.3375/GJ
	33,000 Mmbtu/d (27,800 Mcf/d)	Chicago price = AECO + US$0.672/Mmbtu

Storm's transportation commitments increase from 62 Mmcf per day in 2016 to 91 Mmcf per day in 2018 (interruptible capacity on the Alliance Pipeline adds up to 25% of contracted capacity or 11 Mmcf per day in 2016 and 13 Mmcf per day in 2018).

2016	2017	2018
43.5 Mmcf/d (54,800 GJ/d) Alliance Pipeline Chicago – Cdn$1.35/GJ toll(1)(2)	48.0 Mmcf/d (60,500 GJ/d) Alliance Pipeline Chicago – Cdn$1.35/GJ toll(1)(2)	52.5 Mmcf/d (66,000 GJ/d) Alliance Pipeline Chicago – Cdn$1.35/GJ toll(1)
9.0 Mmcf/d (11,400 GJ/d) Spectra T-north BC Stn 2(3) – Cdn$0.16/GJ toll	24.0 Mmcf/d (30,200 GJ/d) Spectra T-north BC Stn 2(3) – Cdn$0.16/GJ toll	29.0 Mmcf/d (36,500 GJ/d) Spectra T-north BC Stn 2 – Cdn$0.16/GJ toll
9.8 Mmcf/d (12,400 GJ/d) AECO - $0.68/GJ(1)		10.0 Mmcf/d (12,600 GJ/d) Spectra T-north & TCPL sale at AECO - $0.45/GJ toll

(1) Volumes sold at McMahon Gas Plant with pipeline tariff deducted from realized price.
(2) The Chicago – AECO differential has been fixed for 33,000 Mmbtu per day in 2016 at +US$0.672 per Mmbtu and for 35,000 Mmbtu per day in 2017 at +US$0.577 per Mmbtu.
(3) The AECO – BC Station 2 differential has been fixed for 11,000 GJ per day in 2016 at -$0.3375 per GJ and for 5,000 GJ per day in 2017 at -$0.445 per GJ.

COMPARISON OF 2015 RESULTS VERSUS GUIDANCE

Shown below is a comparison of Storm's actual 2015 results to what was provided for guidance.

2015 Guidance	Original Guidance Nov 13, 2014	Last Update Nov 11, 2015	Actual 2015 Results
AECO natural gas price	$3.25 per GJ	$2.60 per GJ	$2.55 per GJ
BC Stn 2 natural gas price	$3.00 per GJ	$1.87 per GJ	$1.70 per GJ
Edmonton light oil price	Cdn$83 per Bbl	Cdn$58 per Bbl	Cdn$57 per Bbl
Estimated average operating costs	$7.50 - $8.00 per Boe	$7.75 - $8.00	$8.00 per Boe
Estimated average royalty rate (% production revenue before hedging)	12% - 14%	6% - 7%	4%
Estimated operations capital (excluding acquisitions & dispositions)	$110.0 million	$92.0 million	$90.7 million
Estimated land and property acquisitions/(dispositions)	$0.0 million	($19.3 million)	($19.2 million)
Estimated cash G&A net of recoveries	$5.3 million	$5.3 million	$5.5 million
Forecast fourth quarter production	14,000 – 14,500 Boe/d (18% oil + NGL)	10,000 – 12,000 (18% NGL)	10,730 Boe/d (17% NGL)
Forecast annual production	11,500 – 12,700 Boe/d (19% oil + NGL)	10,000 – 11,000 (19% oil + NGL)	9,956 Boe/d (19% oil + NGL)
Umbach horizontal wells:			
Drilled	9 gross (9.0 net)	10 gross (10.0 net)	10 gross (10.0 net)
Completed	14 gross (14.0 net)	13 gross (13.0 net)	13 gross (13.0 net)
Starting production	16 gross (16.0 net)	13 gross (13.0 net)	12 gross (12.0 net)

Comparing actual 2015 results to original guidance:

- Forecast annual and fourth quarter production was lower as a result of wells shut in during the second half of 2015 due to the low BC Station 2 natural gas price (loss of 1,400 Boe per day during 2015), plus the mid-year disposal of Alberta properties (loss of 300 Boe).

- The royalty rate was lower as a result of receiving $2.0 million of infrastructure royalty credits and from lower commodity prices (royalty rate in British Columbia depends on well productivity and the natural gas price).

- Operations capital investment was less than forecast due to the third field compression facility at Umbach being deferred into 2016 from October 2015 ($25.0 million estimated total cost less $4.8 million paid in 2015 for major equipment and site preparation).

OUTLOOK

Production in the first quarter of 2016 is forecast to be 13,000 to 14,000 Boe per day and will largely depend on natural gas prices. Production to date in the first quarter has averaged approximately 13,500 Boe per day based on field estimates. Capital investment in the first quarter is expected to be $25.0 million.

Guidance for 2016 is being revised due to the continuing decline in commodity prices which has reduced forecast funds flow. Capital investment in 2016 will be reduced to $80 million which will result in fewer horizontal wells being drilled and completed plus the start-up of the third field compression facility at Umbach being delayed to the fourth quarter of 2016. If commodity prices remain at current levels or continue to decline, capital investment would likely be further reduced in mid-May to approximately $45 million which would result in forecast production averaging 13,000 to 14,000 Boe per day in 2016 and the third field compression facility being delayed until 2017 (requires approximately seven horizontal wells starting production in 2016 to offset declines). Revised guidance for 2016 is provided below with assumed commodity prices being approximately equal to the current forward strip.

2016 Guidance	**Original Guidance Nov 11, 2015**	**Revised Feb 25, 2016**
Chicago natural gas price		US$2.20 per mmbtu
AECO natural gas price	$2.50 per GJ	$2.00 per GJ
BC STN 2 natural gas price	$1.90 per GJ	$1.45 per GJ
Edmonton light oil price	Cdn$57 per Bbl	Cdn$46 per Bbl
Estimated average operating costs	$7.00 - $7.50 per Boe	$7.00 per Boe
Estimated average royalty rate (% production revenue before hedging)	7% - 8%	5% - 6%
Estimated operations capital (excluding acquisitions & dispositions)	$105.0 million	$80.0 million
Estimated land and property acquisitions/(dispositions)		
Estimated cash G&A net of recoveries	$5.0 million	$5.0 million
Estimated funds flow		$39.0 million
Forecast fourth quarter production	20,000 – 21,000 Boe/d (17% NGL)	15,500 – 16,500 Boe/d (18% NGL)
Forecast annual production	16,000 – 18,000 Boe/d (17% oil + NGL)	14,000 – 15,000 Boe/d (18% oil + NGL)
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	14 gross (14.0 net) 14 gross (14.0 net) 16 gross (16.0 net)	12 gross (12.0 net) 10 gross (10.0 net) 12 gross (12.0 net)

Capital investment in 2016 will be directed entirely to Umbach and will include $48 million for drilling and completions plus $24 million for infrastructure (includes remaining $21 million for the third field compression facility). Infrastructure expansion is being funded with debt which is an investment in a long life asset (value doesn't decline with time).

Natural gas sales will be more diversified going forward with Storm's contracted capacity on the Alliance Pipeline for delivery to Chicago. Using forecasted natural gas production in 2016, approximately 22% will be sold at Chicago pricing, 65% sold at an AECO price less a fixed differential and the remaining 13% at the Chicago or BC Station 2 price (whichever is higher). This is much different from 2015 where approximately 50% received the BC Station 2 price which reduced the realized natural gas price and operating netback in the second half of the year.

The high quality and competitive advantages of Storm's Montney land position at Umbach (shallow depth and liquids rich) are reflected in the 2015 all-in PDP FD&A cost of $6.53 per Boe which resulted in a recycle ratio of 1.6X using the 2015 funds flow netback. This is a significant achievement given the low netback in 2015 and reflects Storm's sustainability in the current low commodity price environment. An important objective in 2016 is to achieve further reductions in the PDP FD&A cost in order to remain competitive. For evaluating capital efficiency, PDP FD&A has become a better metric than 1P or 2P FD&A given that it isn't influenced by the accuracy of estimates for future development capital (including required infrastructure).

Storm is still in the early stages of delineating the large liquids rich resource in the Montney formation at Umbach. At the end of 2015, only 20% of Storm's land position was assigned 2P reserves (31 net sections of 155 net sections) which leaves room for significant future reserve growth from the remaining lands which appear to be highly prospective given horizontal well results on offsetting acreage. Over time, data from the wells that have been drilled on offsetting lands is likely to result in reserve additions on Storm's lands.

Storm's results in 2015 reflect a focus on converting Montney resource at Umbach into production and cash flow plus reducing the cost structure (both controllable cash costs and cost of PDP reserve additions). Looking ahead to 2016, the business environment for oil and gas producers continues to become more challenging with the ongoing decline in commodity prices. Storm plans to weather the storm by continuing to build a business for the longer term with a focus on operational excellence which will include:

- further improving capital efficiency by reducing PDP FD&A costs (add length and frac stages on horizontal wells at Umbach;
- increasing the funds flow netback by decreasing controllable cash costs;
- identifying and capturing opportunities that increase future net asset value; and
- maintaining a strong balance sheet so that growth can be accelerated when commodity prices improve.

Storm's land position in the Horn River Basin continues to be a core, long-term asset with significant leverage to higher natural gas prices.

In closing, I would like to thank Storm's employees for their efforts in 2015 which resulted in record levels of production and significant improvements in capital efficiency. In addition, the invaluable advice, guidance, and support provided by Storm's Directors continues to be very much appreciated.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 25, 2016

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.

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 February 25, 2016 for the three months and year ended December 31, 2015.

RESERVES AT DECEMBER 31, 2015

Storm's year-end reserve evaluation effective December 31, 2015 was prepared by InSite Petroleum Consultants Ltd. ("InSite") under date of February 16, 2016. InSite has evaluated all of Storm's crude oil, NGL and natural gas reserves. The InSite price forecast at December 31, 2015 was used to determine all estimates of future net revenue (also referred to as net present value or 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 ("NI") 51-101. In addition to the information disclosed in this report, more detailed information will be included in Storm's Annual Information Form.

Summary

- Proved developed producing ("PDP") reserves increased 54% to total 20,810 Mboe with additions replacing 300% of 2015 production.
- Total proved ("1P") reserves increased 23% to total 73,434 Mboe with additions replacing 480% of 2015 production.
- Total proved plus probable ("2P") reserves increased 14% to total 100,722 Mboe with additions replacing 450% of 2015 production.
- Total proved reserves were 73% of total proved plus probable reserves, an improvement from 68% in 2014.
- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $6.53 per Boe for PDP, $3.38 per Boe for 1P and was $0.50 per Boe for 2P.
- Recycle ratio using the all-in FD&A cost was 1.3 for PDP additions, 2.6 for 1P additions, and 17.3 for 2P additions using the 2015 field operating netback of $8.68 per Boe excluding hedging gains or losses.
- Technical revisions were primarily due to horizontal well performance exceeding expectations which increased PDP reserves by 1,221 Mboe, 1P reserves by 6,700 Mboe and 2P reserves by 5,482 Mboe.
- Economic factors were the elimination of undeveloped drilling locations at the Horn River Basin ("HRB") in northeast British Columbia, reducing 1P reserves by 2,364 Mboe and 2P reserves by 4,462 Mboe.
- Breaking down 2P reserves by area, 96.2% is at Umbach, 3.4% at the HRB and 0.4% is at Grande Prairie.
- Future development costs ("FDC") were $435.4 million on a 1P basis and $543.3 million on a 2P basis which represents approximately five years of activity in the evaluation based on forecast capital investment in 2016.
- At Umbach the 100% working interest lands were assigned 70 net 2P horizontal drilling locations at an average of 4.7 Bcf gross raw gas, an increase of 7% from 4.4 Bcf gross raw gas assigned in 2014. On the 60% working interest lands, 20.4 net 2P horizontal drilling locations were assigned an average of 3.7 Bcf gross raw gas, an increase of 16% from 3.2 Bcf gross raw gas assigned in 2014.

- Ultimate 2P recovery for the producing horizontal wells at Umbach is forecast to average 5.5 Bcf gross raw gas for the wells drilled in 2015, 6.2 Bcf gross raw gas for the wells drilled in 2014 (revised up from 5.4 Bcf last year), and 4.4 Bcf gross raw gas for the wells drilled in 2013 (revised up from 4.2 Bcf last year).

- At Umbach, 2P reserves were recognized in the upper Montney only on 20% or 31.2 net sections of Storm's 153 net sections in the area with DPIIP averaging 48 Bcf gross raw gas per section in the upper Montney (total net DPIIP 1.5 Tcf on 31.2 net sections). Forecast recovery of DPIIP totals 38% for 2P reserves.

- Umbach 2P FDC totaled $514.0 million for 90.4 net 2P future horizontal drilling locations which equals an average of $5.7 million per location and includes $0.6 million per location for future infrastructure expansion (last year was $484.0 million for 79.4 net locations which was $6.1 million per future horizontal drilling location and included $0.8 million per location for future infrastructure expansion).

(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, 2015, which will include complete disclosure of oil and gas reserves and other information in accordance with NI 51-101, will be contained within the Annual Information Form 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, 2015
(Before deduction of royalties payable, not including royalties receivable)

	Light Crude Oil (Mbbls)	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	-	104,004	3,476	20,810
Proved non-producing	-	5,926	196	1,183
Total proved developed	-	109,930	3,672	21,993
Proved undeveloped	-	258,552	8,349	51,441
Total proved	-	368,483	12,020	73,434
Probable additional	-	138,588	4,190	27,288
Total proved plus probable	-	507,071	16,210	100,722

Numbers in this table may not add due to rounding.

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

	2015	2014	2013
PDP	5 years	4 years	4 years
1P	19 years	16 years	12 years
2P	26 years	24 years	23 years

Gross Company Reserve Reconciliation for 2015
(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, 2014 - opening balance	13,487	59,551	28,473	88,024
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	1,714	14,950	4,507	19,457
Category transfer	9,471	-	-	-
Dispositions	(1,450)	(1,768)	(2,377)	(4,145)
Technical revisions	1,221	6,700	(1,218)	5,482
Economic factors	-	(2,364)	(2,098)	(4,462)
Production	(3,634)	(3,634)	-	(3,634)
December 31, 2015 – closing balance	20,810	73,434	27,288	100,722

Numbers in this table may not add due to rounding.

Future Development Costs ("FDC")

	Undiscounted Proved Expenditures ($M)	Undiscounted Proved Plus Probable Expenditures(M$)
2016	41,300	41,300
2017	98,379	98,379
2018	109,627	118,262
2019	83,591	119,343
2020	79,591	136,072
2021	22,954	29,909
Total FDC - undiscounted	435,442	543,266
Total FDC – discounted at 10%	340,521	413,996
HRB	$12.3 million	$28.9 million
Umbach	$423.1 million	$514.4 million

Note: InSite escalates capital costs at 2% per year after 2016.
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)	2015	2014	2013	3 Year Total
Net capital investment (000s)	$ 71,509	$ 194,555	$ 52,444	$ 318,508
Total capital	$ 71,509	$ 194,555	$ 52,444	$ 318,508
Total reserve additions (Mboe)	10,956	8,456	3,047	22,457
All-in PDP FD&A cost	$ 6.53	$ 23.01	$ 17.21	$ 14.18

Total Proved FD&A Cost (All-In)	2015	2014	2013	3 Year Total
Net capital investment (000s)	$ 71,509	$ 194,555	$ 52,444	$ 318,508
Change in FDC (000s)	(12,275)	288,242	56,600	332,567
Total capital including change in FDC (000s)	$ 59,234	$ 482,797	$ 109,044	$ 651,075
Total reserve additions (Mboe)	17,517	41,334	8,270	67,121
All-in 1P FD&A cost (per Boe)	$ 3.38	$ 11.68	$ 13.19	$ 9.70

Total Proved Plus Probable FD&A Cost (All-In)	2015	2014	2013	3 Year Total
Net capital investment (000s)	$ 71,509	$ 194,555	$ 52,444	$ 318,508
Change in FDC (000s)	(63,288)	287,686	89,829	314,227
Total capital including change in FDC (000s)	$ 8,221	$ 482,241	$ 142,273	$ 632,735
Total reserve additions (Mboe)	16,332	50,030	14,538	80,900
All-In 2P FD&A cost (per Boe)	$ 0.50	$ 9.64	$ 9.79	$ 7.82

Recycle Ratio				
Operating netback per Boe excluding hedging	$ 8.68	$ 21.19	$ 20.43	$ 15.00
Recycle ratio for all-in PDP FD&A cost	1.3	0.9	1.2	1.1
Recycle ratio for all-in 1P FD&A cost	2.6	1.8	1.5	1.5
Recycle ratio for all-in 2P FD&A cost	17.4	2.2	2.1	1.9

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

Total Proved F&D Cost	2015	2014	2013	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 95,099	$ 106,604	$ 67,450	$ 269,153
Change in FDC (000s)	18,604	288,242	77,282	384,128
Total capital including change in FDC (000s)	$ 113,703	$ 394,846	$ 144,732	$ 653,281
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	14,950	38,707	10,356	64,013
1P F&D cost (per Boe)	$ 7.61	$ 10.20	$ 13.98	$ 10.21

Total Proved Plus Probable F&D Cost	2015	2014	2013	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 95,099	$ 106,604	$ 67,450	$ 269,153
Change in FDC (000s)	30,717	287,686	134,903	453,306
Total capital including change in FDC (000s)	$ 125,816	$ 394,290	$ 202,353	$ 722,459
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	19,457	45,001	18,823	83,281
2P F&D cost	$ 6.47	$ 8.76	$ 10.75	$ 8.67

Net Present Value Summary (before tax) as at December 31, 2015

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPVs include a deduction for estimated future well abandonment costs.

	Undiscounted (000s)	Discounted at 5% (000s)	Discounted at 10% (000s)	Discounted at 15% (000s)	Discounted at 20% (000s)
Proved producing	341,642	263,305	213,054	178,793	154,232
Proved non-producing	17,777	13,009	10,051	8,092	6,724
Total proved developed	359,419	276,314	223,105	186,885	160,956
Proved undeveloped	627,336	367,602	218,610	128,126	70,612
Total proved	986,755	643,916	441,715	315,012	231,567
Probable additional	516,188	266,667	150,273	90,456	57,169
Total proved plus probable	1,502,943	910,582	591,989	405,467	288,736

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2015

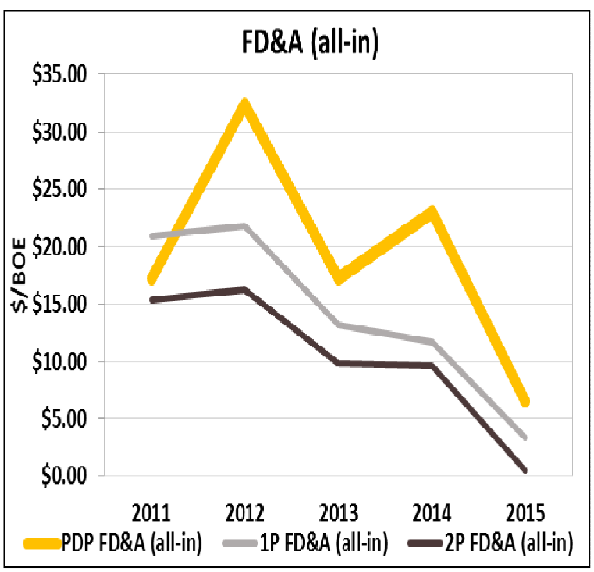
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPVs each include a deduction for estimated future well abandonment costs.

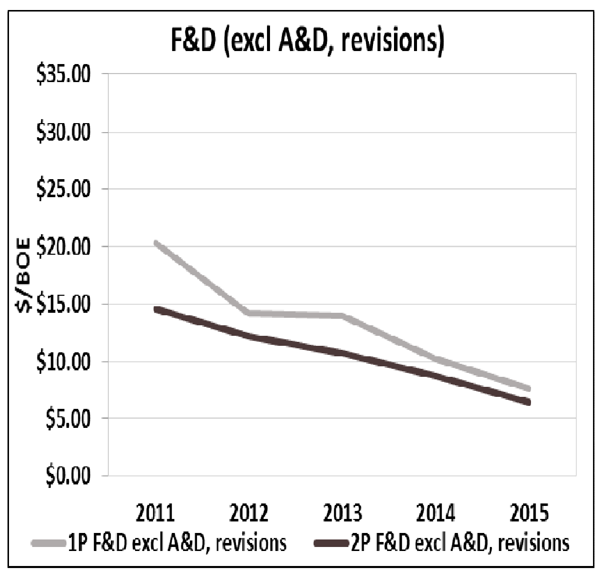
	Undiscounted (000s)	Discounted at 5% (000s)	Discounted at 10% (000s)	Discounted at 15% (000s)	Discounted at 20% (000s)
Proved producing	341,642	263,305	213,054	178,793	154,232
Proved non-producing	17,777	13,009	10,051	8,092	6,724
Total proved developed	359,419	276,314	223,105	186,885	160,956
Proved undeveloped	480,971	280,602	164,057	92,379	46,319
Total proved	840,390	556,916	387,162	279,264	207,275
Probable additional	382,688	195,748	108,701	64,148	39,522
Total proved plus probable	1,223,078	752,663	495,863	343,412	246,797

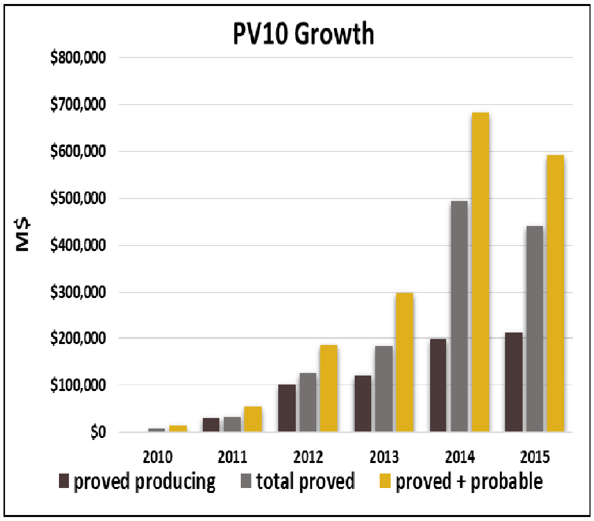
Numbers in this table may not add due to rounding.

InSite Escalating Price Forecast as at December 31, 2015

	WTI Crude Oil (US$/Bbl)	Edmonton Par Crude Oil (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)
2016	45.00	55.64	2.50	2.71
2017	55.00	68.33	3.00	3.27
2018	65.00	78.23	3.50	3.74
2019	70.00	81.22	3.75	3.87
2020	75.00	85.06	4.00	4.05






PV10 Growth
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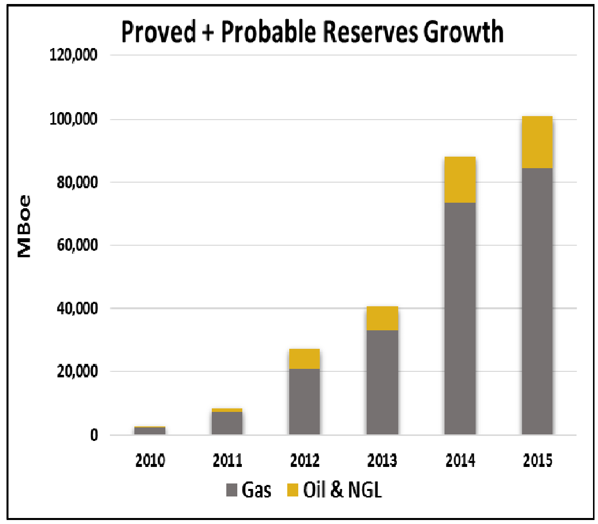
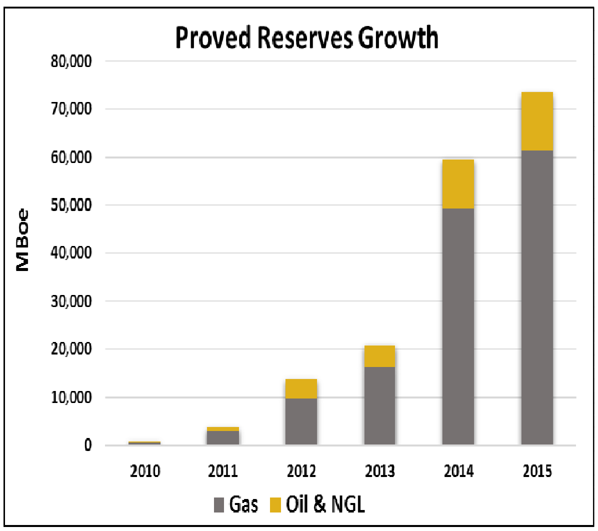
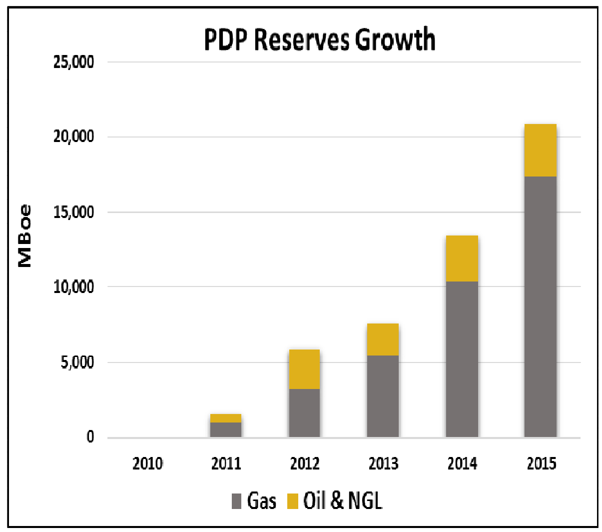
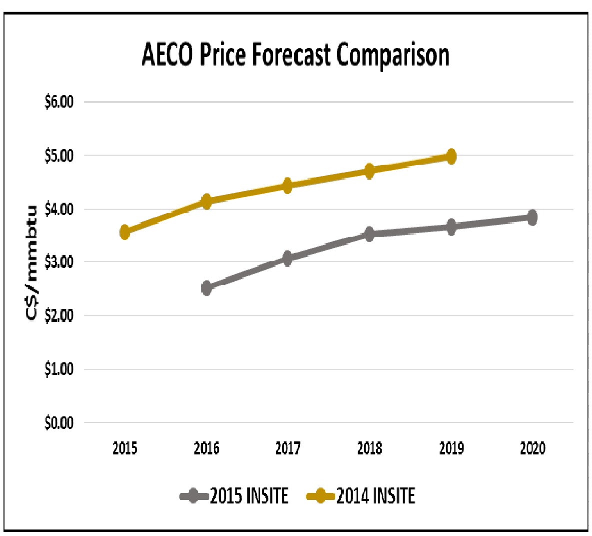
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
2010
2011
2012
2013
2014
2015
proved producing
total proved
proved + probable


Proved + Probable Reserves Growth
MBoe
120,000
100,000
80,000
60,000
40,000
20,000
0
2010
2011
2012
2013
2014
2015
Gas
Oil & NGL


Proved Reserves Growth
MBoe
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
2010
2011
2012
2013
2014
2015
Gas
Oil & NGL


PDP Reserves Growth
MBoe
25,000
20,000
15,000
10,000
5,000
0
2010
2011
2012
2013
2014
2015
Gas
Oil & NGL


AECO Price Forecast Comparison
C$/mmbtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
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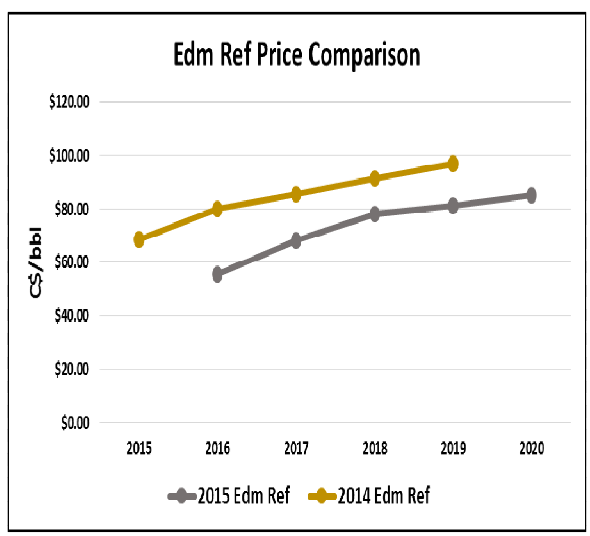
2016
2017
2018
2019
2020
2015 INSITE
2014 INSITE


Edm Ref Price Comparison
C$/bbl
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
2015
2016
2017
2018
2019
2020
2015 Edm Ref
2014 Edm Ref

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, 2015. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2015 and 2014, (ii) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2015, and (iii) the press release issued by the Company on February 25, 2016, 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 February 25, 2016.

See "Forward-Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" beginning on pages 36 and 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, 2015 and the unaudited condensed interim consolidated financial statements for the three months ended December 31, 2015, 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, 2015 and 2014. 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, 2014.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Year to December 31, 2015

Although 2015 was operationally a satisfactory year for Storm, the year was dominated by unprecedented price declines for the Company's products. Natural gas, which represented more than 80% of Storm's Boe production base in 2015, was, and continues to be over supplied throughout North America, resulting in all key pricing indices continuing to fall throughout the year. Normally robust winter heating demand was affected by mild weather for the winter of 2015-2016 and US production continued to grow in the face of falling prices. Natural gas production in Western Canada generally trades on one of two markets: AECO or Station 2, with Station 2 being smaller and less liquid and which historically has traded at a modest discount to AECO, representing the approximate transportation cost between the two markets. In 2015, due to pipeline closures, curtailments and interruptions on the TCPL system in Alberta, as well as growing production in the Station 2 catchment area, additional volumes of natural gas were flowed to Station 2, causing the AECO-Station 2 pricing differential to increase considerably. For 2015, approximately 50% of Storm's natural gas production was sold at the Station 2 index price and thus was exposed to both lower prices for natural gas and widening of the AECO-Station 2 pricing differential. Remaining gas volumes were largely sold at the AECO monthly index. In addition, pricing for crude oil fell to levels not seen for more than a decade, a consequence of expanding US production, high storage levels and geopolitical circumstances in the Middle East. Although Storm had little crude oil production in 2015, and none in the second half of the year, pricing for the majority of the Company's NGL stream is based on crude oil reference prices.

The magnitude of the price collapse deserves emphasis. In the final quarter of 2015, the realized price for natural gas was $1.78 per Mcf, or 32% of the price in the first quarter of 2014: and the realized price for NGL in the final quarter of 2015 was 40% of the price for the first quarter of 2014. Weakness in index prices was compounded by a growing AECO-Station 2 differential, which grew from $0.48 in the first quarter of 2014 (already high by historical standards) to $1.30 in the last quarter of 2015.

As 2015 progressed, Storm's position became increasingly defensive. Favourable market conditions in the second quarter enabled the Company to issue eight million shares at the price of $4.55 for net proceeds of $34.3 million. Early in the third quarter, the Company sold almost all of its Alberta properties for proceeds of $23.6 million. The properties sold, which produced about 600 Boe per day prior to sale, were not core to the Company's business, received no funding under Storm's capital allocation process and had high operating costs. Funds obtained from the equity issue and property sale were used to reduce bank borrowings and to support the Company's capital program. The consequence was that at year end, bank borrowings totaled $57.1 million, or 41% of the Company's credit facility, providing the Company with the financial flexibility to ramp up production in response to improved prices, or to pursue advantageous land or equipment purchases. Debt including working capital deficiency at year end amounted to $61.7 million, or 1.6 times 2015 cash flow.

Year over year, total production grew by 43%, all from the Umbach area in northeast British Columbia. Growth in production would have been higher as Umbach production was shut in for four weeks in the second quarter due to scheduled maintenance at a processing facility and, in the third and fourth quarters, the Company shut in production of about 2,800 Boe per day in response to low gas prices. Annual production was reduced by about 1,950 Boe per day as a result of these curtailments. In the face of continuing 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 14%, transportation costs per Boe fell by 37%, and general and administrative and interest costs per Boe were marginally higher. However, increased production and a lower cost structure were insufficient to offset the pricing collapse with the result that year-over-year funds from operations fell by 14%. In the first two quarters of 2015, funds from operations did increase year over year; however, the accelerating commodity price rout in the second half of the year saw these first half gains more than reversed. Storm's active hedging program was an important contributor to financial stability, with realized hedging gains totaling $15.3 million, or 22% of revenue from product sales.

The Company's capital program in 2015 was exclusively focused on the Umbach property, with net outlays totaling $71.5 million, of which $5.4 million was spent on exploration and evaluation, with the remaining amount on property and equipment. A total of $52 million was spent on drilling and completions and $36 million on infrastructure expansion. At the beginning of 2015, Storm had an inventory of eight standing wells of which five awaited completion. Ten wells were drilled in the year with 12 wells being brought on production, resulting in an inventory of six wells drilled with four awaiting completion at the end of 2015. Storm can thus replace production declines, or add production in 2016, at a relatively modest cost. Effective December 1, 2015, arrangements entered into to diversify marketing and transportation resulted in a higher natural gas price and production increasing to approximately 13,600 Boe per day, a level that is likely to continue into the first quarter of 2016. Storm's facility capacity is in the range of 14,000-15,000 Boe per day, with expansion beyond that amount contingent on the construction of a third compression facility. Commodity prices and cash flow will drive the Company's capital program in 2016, which is expected to have an exclusive focus on Umbach. The Umbach property offers reasonable year round access: activity levels can be readily increased or reduced in response to commodity price movements. The capital program for 2016 is thus flexible and will be subject to amendment throughout the year. Storm's longer term business plan will not change – what may change is timing of execution.

Quarter to December 31, 2015

The final quarter of 2015 was the weakest quarter financially of 2015. Although production was 5% higher than the final quarter of 2014 and 11% higher than the third quarter of 2015, revenue for the quarter was only 51% of the prior year amount, with per-Boe revenue being 49% of the 2014 amount and 80% of the amount for the immediately preceding quarter. Production for the months of October and November averaged approximately 9,300 Boe per day, with production for December increasing to approximately 13,600 Boe per day, a level likely to be maintained until additional compression capacity is commissioned. Increased production in December 2015 was driven by new natural gas marketing arrangements with 64% of the month's production being sold at the AECO monthly index price (adjusted for a transportation differential): 16% was sold at the Chicago City Gate spot price, with the volume of natural gas being sold at Station 2 falling to 20%.

Funds from operations for the quarter totaled $9.2 million, about 66% of the prior year amount but 15% greater than the third quarter of 2015. In addition to production growth, increased funds from operations over the immediately preceding quarter resulted from the receipt of royalty credits, reduced operating and transportation costs and hedging gains. Using annualized funds from operations for the fourth quarter, year-end debt including working capital deficiency to cash flow amounted to 1.7 times.

In spite of the dismal commodity price environment, the Company managed to report a profit of $1.9 million for the quarter compared to losses in the same quarter of 2014 and the third quarter of 2015. In addition to reduced costs referenced above, increased reserves from Storm's successful drilling program in 2015 plus the mid-year sale of the high cost Alberta CGU, resulted in the charge for depletion and depreciation for the final quarter falling to $8.42 per Boe, a reduction of 22% when compared to the final quarter of 2014.

Capital expenditures for the quarter totaled $31.0 million. Included in this amount were drilling and completion costs of $22.4 million, corresponding to the drilling of four wells and completion of six wells in the quarter. Facility, equipping and gathering costs totaled $4.0 million including equipment costs relating to the third compression facility. Finally, the Company purchased 11 additional sections at Umbach for $4.4 million.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				Year Ended December 31, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	46,084	1,639	-	9,320
Horn River Basin – NE BC	1,044	-	-	174
Grande Prairie – AB	1,528	28	179	462
Total	48,656	1,667	179	9,956

				Year Ended December 31, 2014
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	27,291	1000	-	5,548
Horn River Basin – NE BC	2,026	-	-	338
Grande Prairie – AB	3,750	64	405	1,094
Total	33,067	1,064	405	6,980

				Three Months Ended December 31, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach – NE BC	53,142	1,872	-	10,729
Horn River Basin – NE BC(2)	-	-	-	-
Grande Prairie Area – AB	5	-	-	1
Total	53,147	1,872	-	10,730

(1) Crude oil production was sold early third quarter of 2015.
(2) Production shut in due to pricing.

Three Months Ended December 31, 2014				
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	43,409	1,540	-	8,775
Horn River Basin – NE BC	1,843	-	-	307
Grande Prairie Area – AB	3,842	65	385	1,091
Total	49,094	1,605	385	10,173

Total Boe production in 2015 increased by 43% when compared to 2014. The year-over-year increase in production for natural gas and NGL came from Umbach where the Company began production from 12 wells (12 net) during the year. Daily production per million shares outstanding at the end of 2015 averaged 83 Boe per day, compared to 63 Boe per day in 2014, an increase of 32%. The increase in production per share is reduced by the dilutive effect of an equity issue in the second quarter of 2015.

In the fourth quarter of 2015, average Boe per day volumes increased by 5% when compared to the fourth quarter of 2014. Production of natural gas amounted to 83% of total Boe production in the fourth quarter of 2015, up from earlier quarters as a result of increased production in the quarter from the tie-in of three new wells at Umbach. Daily production per million shares outstanding at the end of the quarter averaged 90 Boe per day compared to 91 Boe per day for the fourth quarter of 2014 and 81 Boe per day in the immediately preceding quarter.

During 2015 approximately 1,950 Boe per day of production was shut in, largely due to uneconomical gas pricing.

Production increases for natural gas and NGL, when compared to the prior year, are a consequence of growth at Umbach where the Company produced from 35 wells (31.4 net) during the year. Crude oil producing properties were sold in July 2015. Production to date in 2016 is currently averaging 13,500 Boe per day based on field estimates.

The Horn River Basin ("HRB") produces dry natural gas, while Umbach produces natural gas and associated NGL. Production in 2015 approximated 81% natural gas, 17% NGL and 2% light oil with fourth quarter production averaging 83% natural gas and 17% NGL.

In mid-July the Company sold largely all of its Alberta properties for proceeds of approximately $23.6 million.

Average Daily Production

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Natural gas (Mcf/d)	53,147	49,094	48,656	33,067
Natural gas liquids (Bbls/d)	1,872	1,605	1,667	1,064
Crude oil (Bbls/d)	-	385	179	405
Total (Boe/d)	10,730	10,173	9,956	6,980

Production Profile and Per-Unit Prices(1)

	Three Months to Dec. 31, 2015		Three Months to Dec. 31, 2014		Year Ended Dec. 31, 2015		Year Ended Dec. 31, 2014	
	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%	$ 1.78	80%	$ 3.85	81%	$ 2.39	79%	$ 4.58
Natural gas liquids - Bbl	17%	33.50	16%	56.15	17%	36.10	15%	69.90
Crude oil - Bbl	-	-	4%	68.01	2%	50.84	6%	88.10
Per Boe	100%	$ 14.67	100%	$ 29.99	100%	$ 18.64	100%	$ 37.48

(1) Before realized hedging gains of $4.20 per Boe for the year ended December 31, 2015 (2014 – loss of $1.26) and hedging gains of $4.20 per Boe for the three months ended December 31, 2015 (2014 - gain of $0.52).

Approximately 50% of Storm's natural gas production in 2015 was sold at the Station 2 daily spot price, 45% at the AECO monthly index price less a fixed price differential, 3% at the AECO daily index price and 2% at the Chicago daily index price. Effective December 1, 2015, Storm obtained transportation for 55,000 GJ per day on the Alliance pipeline to Chicago, resulting in natural gas volumes priced under the Station 2 index falling to 3% for the month. This should continue into the first quarter of 2016.

A summary of reference prices for 2015 and 2014 is as follows: Storm's realized prices differ due to heat content of the Company's natural gas.

	2015			2014		
	AECO Daily Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)	AECO Daily Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)
Q1	2.81	2.02	51.93	5.42	4.94	99.83
Q2	2.52	2.01	67.72	4.44	4.20	105.61
Q3	2.75	1.72	56.23	3.81	3.54	97.16
Q4	2.34	1.04	52.95	3.41	2.93	75.69
Average for year	2.55	1.70	57.21	4.27	3.90	94.57

The portion of Storm's natural gas sold at the AECO monthly index price aligns production with the Company's natural gas hedges.

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 grew in geographic areas where production is normally directed to Station 2. The consequence was a considerable widening in the AECO – Station 2 differential with average Station 2 prices for 2015 at a discount to AECO of $0.85 compared to $0.37 for 2014. It should be recognized that the widening AECO – Station 2 differential has emerged in a period of collapsing natural gas prices. The pipeline restrictions that contributed to the widening differential were partially reduced in December 2015 which may result in a lower differential in future reporting periods.

Storm's realized price for 2015 was $2.39 per Mcf, with the price higher than index prices as a result of sales gas at Umbach having a higher heat content.

The realized price for NGL in 2015 fell 48% relative to 2014. Storm's NGL stream in 2015 contained 60% condensate and pentanes, which are generally priced with reference to crude oil. Pricing suffered accordingly and Storm received an average price of $50.78 per barrel for the year. Further, the price for propane collapsed with Storm's realized plantgate price being a negative $3.80 per barrel for the year. For 2015, WTI averaged US$48.80 per barrel and Edmonton light oil was Cdn$57.21 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$5.10 per barrel, compared to Cdn$8.13 per barrel in 2014. Production of crude oil is now an insignificant part of the Company's operations and is likely to remain so under the Company's current investment program.

As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production will also increase. The importance of this is illustrated by the contribution from NGL in 2015. NGL comprised 17% of Boe production but amounted to 32% of revenue from product sales.

Average quarterly natural gas index prices in gigajoules are as follows:

(Cdn$/GJ)	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
AECO Monthly Index	2.51	3.80	2.62	4.19
AECO Daily Index (spot)	2.34	3.41	2.55	4.27
BC Station 2 Daily Index (spot)	1.04	2.93	1.70	3.90

Revenue from Product Sales(1)

(000s)	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Natural gas	$ 8,710	$ 17,369	$ 42,436	$ 55,316
Natural gas liquids	5,770	8,292	21,969	27,144
Crude oil	-	2,409	3,331	13,020
Total	$ 14,480	$ 28,070	$ 67,736	$ 95,480

(1) Excludes hedging gains and losses.

Revenue from product sales for 2015 decreased by 29% when compared to 2014, with an average price per Boe for 2015 of $18.64, a year-over-year decrease of 50%. Production grew by 43%; however, this was insufficient to offset the calamitous fall in commodity prices.

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – 2014	$ 55,316	$ 27,144	$ 13,020	$ 95,480
Effect of increased (decreased) production	26,059	15,388	(7,248)	40,709
Effect of changes in average product prices	(38,939)	(20,563)	(2,441)	(68,453)
Revenue from product sales - 2015	$ 42,436	$ 21,969	$ 3,331	$ 67,736

Year-over-year price declines in 2015 reduced annual revenues from product sales by more than 50%, more than exceeding the contribution from what was a year of impressive production growth.

Revenue from product sales for the fourth quarter of 2015 decreased by 48% when compared to the fourth quarter of 2014 and by 11% when compared to the immediately preceding quarter. Quarterly production volumes grew 5% year over year and by 11% when compared to the third quarter of 2015. The disparity between growth in production and in revenue corresponds to price declines, as follows:

Realized Prices per Commodity Unit	Three Months to Dec. 31, 2015	Three Months to Sept. 30, 2015	Three Months to Dec. 31, 2014
Natural gas (Mcf/d)	$ 1.78	$ 2.46	$ 3.85
Natural gas liquids (Bbls/d)	$ 33.50	$ 33.32	$ 56.15
Crude oil (Bbls/d)	$ -	$ 55.93	$ 68.01
Total	$ 14.67	$ 18.33	$ 29.99

Realized and Unrealized Gain (Loss) 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 period, plus cash settlements relating to contracts which the Company terminated prior to the expiry date.

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

The unrealized gain (loss) on commodity price contracts results from the mark-to-market valuation of the unexpired portion of hedging contracts outstanding at the end of the reporting period. The change in fair value recognizes not only the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period, but includes the opening value of contracts which have come to term during the reporting period.

	Year Ended Dec. 31, 2015			Year ended Dec. 31, 2014		
Realized gain (loss)						
Liquids	$ 5,137	$ 78.42	/Bbl	$ (68)	$ (0.46)	/Bbl
Natural gas	10,114	$ 0.57	/Mcf	(3,130)	$ (0.26)	/Mcf
Total realized gain (loss) – cash	$ 15,251	$ 4.20	/Boe	$ (3,198)	$ (1.26)	/Boe

	Year Ended December 31, 2015					Year Ended December 31, 2014				
Unrealized gain (loss)										
Liquids – change in fair value	$	(1,436)	$	(2.13)	/Bbl	$	5,060	$	34.24	/Bbl
Natural gas – change in fair value		(3,500)	$	(0.20)	/Mcf		9,108	$	0.75	/Mcf
Total unrealized gain (loss) – non-cash	$	(4,936)	$	(1.36)	/Boe	$	14,168	$	5.56	/Boe

	Three Months to Dec. 31, 2015					Three Months to Dec. 31, 2014				
Realized gain (loss)										
Liquids	$	-	$	-	/Bbl	$	809	$	22.84	/Bbl
Natural gas		4,144	$	0.85	/Mcf		(323)	$	(0.07)	/Mcf
Total realized gain (loss) – cash	$	4,144	$	4.20	/Boe	$	486	$	0.52	/Boe

	Three Months to Dec. 31, 2015					Three Months to Dec. 31, 2014				
Unrealized gain (loss)										
Liquids – change in fair value	$	1,289	$	7.49	/Bbl	$	4,570	$	129.02	/Bbl
Natural gas – change in fair value		763	$	0.16	/Mcf		8,957	$	1.98	/Mcf
Total unrealized gain (loss) – non-cash	$	2,052	$	2.08	/Boe	$	13,527	$	14.45	/Boe

The Company had in place the following hedging arrangements at the date of this report:

Period Hedged	Daily Volume	Average Price
Crude Oil Collar		
Jan – Dec 2016	500 Bbls	$75.00 - $90.75 Cdn$/Bbl
Natural Gas Swaps		
Q1 – 2016	5,000 GJ	AECO Cdn$3.06/GJ
Jan – Dec 2016	20,000 GJ	AECO Cdn$2.98/GJ
Natural Gas Differential Swaps		
Jan – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Jan – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

In the year to December 31, 2015, the Company realized gains from hedges in place during the year in the amount of $15.3 million compared to losses of $3.2 million in 2014. Realized hedging gains during the fourth quarter of 2015 totaled $4.1 million which added $4.20 per Boe to the field netback, compared to realized gains of $0.5 million, or $0.52 per Boe, for the same quarter of 2014. In January 2015 the Company terminated all of the Company's then existing crude oil contracts in exchange for $5.1 million. This amount is recognized as part of the realized gain on commodity price contracts in the consolidated statement of income (loss) for the year ended December 31, 2015. The fair market value of hedges in place at December 31, 2015 was $8.0 million.

Natural gas volumes are hedged at the AECO monthly index price and the Company sells equal physical volumes of natural gas at the same price.

The Company's hedging 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 cash 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, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ (54)	$ 3,455	$ 2,982	$ 13,151
Percentage of revenue from product sales	(0.4%)	12.3%	4.4%	13.7%
Per Boe	$ (0.05)	$ 3.69	$ 0.82	$ 5.16

Royalties in 2015 decreased by 77% when compared to 2014 and were eliminated in the final quarter of 2015 when compared to the same quarter of 2014. Decreased production revenue as a result of lower commodity pricing and the resulting lower royalty rates were the primary drivers of decreased royalties year over year; however, royalties also decreased as a result of the receipt in 2015 of an infrastructure royalty credit of $2.0 million. Of this amount, $1.0 million was received in the first quarter of 2015 with the remaining amount received in the final quarter of the year, with the anomalous result that the Company had no Crown royalty charge for the quarter. Normally production in British Columbia would be subject to a minimum rate of 6%.

Future production will further benefit from British Columbia's Infrastructure Royalty Credit Program. Since 2012, Storm has received approval for $14.6 million of royalty credits for various projects. Storm received credits of $0.8 million in 2013, $1.9 million in 2014 and $2.0 million in 2015. The remaining credits total $9.9 million which will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary.

In March 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 $0.7 million per well, depending on the total measured vertical depth of the well. In conjunction with this change, 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 of the Infrastructure Royalty Credit and the Deep Well Royalty Credit programs.

The Alberta government's recent royalty review, although incomplete, will not have a material impact on Storm given the limited production base in Alberta.

Production Costs

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ 6,920	$ 7,864	$ 29,076	$ 23,781
Percentage of revenue from product sales	47.8%	27.9%	42.8%	25.0%
Per Boe	$ 7.01	$ 8.40	$ 8.00	$ 9.33

Total production costs for 2015 increased by 22% when compared to 2014 and decreased by 12% for the final quarter of 2015 when compared to the same quarter of 2014. The year-over-year increase in total production costs is largely aligned with increased production at Umbach as per-Boe charges have continued to decline.

Production costs per Mcf of natural gas for the fourth quarter of 2015 averaged $1.42 with total production costs averaging $7.01 per Boe, a year-over-year reduction of 17%. Production costs of natural gas liquids are included with natural gas costs. For the year-over-year comparison, per-Boe production costs averaged $8.00 in 2015 and $9.33 in 2014, a reduction of 14%. Contributing to the reduction in production costs was the July disposal of certain higher cost properties in Alberta.

Growing production results in the fixed cost component of production costs falling. In addition, falling service costs, particularly in the second half of 2015, also contributed to the decline in total and per-unit production costs. Lower cost natural gas growing as a percentage of the Company's production base is also a factor.

Transportation Costs

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ 783	$ 1,791	$ 4,118	$ 4,594
Percentage of revenue from product sales	5.4%	6.4%	6.1%	4.8%
Per Boe	$ 0.79	$ 1.91	$ 1.13	$ 1.80

Transportation costs largely comprise pipeline tariffs from the sales point at the processing facility for natural gas, and trucking costs for wellhead condensate in British Columbia. Total transportation costs for 2015 decreased by 10% over 2014 as a result of selling oil properties in the Grande Prairie area while per-Boe transportation costs declined 37% due to lower NGL trucking charges and from the sale of higher cost oil properties in the Grande Prairie area. Transportation costs for the final quarter of 2015 decreased by 56% over the same quarter of 2014 while per-Boe transportation costs declined 59% mainly due to new natural gas marketing arrangements. The disposal of Alberta properties in 2015 should result in a sustainable reduction in transportation costs in future periods.

Field Netbacks

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

	Year Ended December 31, 2015			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.39	$ 36.10	$ 50.84	$ 18.64
Royalties	0.02	(5.09)	(2.45)	(0.82)
Production costs	(1.57)	-	(18.22)	(8.00)
Transportation costs	(0.14)	(2.17)	(4.63)	(1.13)
Field operating netback before hedging	$ 0.70	$ 28.84	$ 25.54	$ 8.69
Realized hedging gains	0.57	-	78.42	4.20
Total operating income per commodity unit	$ 1.27	$ 28.84	$ 103.96	$ 12.89
Total operating income (000s)	$ 22,453	$ 17,549	$ 6,809	$ 46,811

Note: Production costs of natural gas liquids are included with natural gas costs.

	Year Ended December 31, 2014			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 4.58	$ 69.90	$ 88.10	$ 37.48
Royalties	(0.39)	(13.55)	(21.45)	(5.16)
Production costs	(1.72)	-	(20.30)	(9.33)
Transportation costs	(0.20)	(3.60)	(5.58)	(1.80)
Field operating netback before hedging	$ 2.27	$ 52.75	$ 40.77	$ 21.19
Realized hedging losses	(0.26)	-	(0.46)	(1.26)
Total operating income per commodity unit	$ 2.01	$ 52.75	$ 40.31	$ 19.93
Total operating income (000s)	$ 24,316	$ 20,483	$ 5,957	$ 50,756

	Three Months Ended December 31, 2015			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.78	$ 33.50	$ -	$ 14.67
Royalties	0.15	(3.94)	-	0.05
Production costs	(1.42)	-	-	(7.01)
Transportation costs	(0.10)	(1.66)	-	(0.79)
Field operating netback before hedging	$ 0.41	$ 27.90	-	$ 6.92
Realized hedging gains	0.85	-	-	4.20
Total operating income per commodity unit	$ 1.26	$ 27.90	-	$ 11.12
Total operating income (000s)	$ 6,174	$ 4,800	$ -	$ 10,974

	Three Months Ended December 31, 2014			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 3.85	$ 56.15	$ 68.01	$ 29.99
Royalties	(0.30)	(10.27)	(16.81)	(3.69)
Production costs	(1.61)	-	(16.94)	(8.40)
Transportation costs	(0.20)	(4.62)	(5.51)	(1.91)
Field operating netback before hedging	$ 1.74	$ 41.26	$ 28.75	$ 15.99
Realized hedging gains (losses)	(0.07)	-	22.84	0.52
Total operating income per commodity unit	$ 1.67	$ 41.26	$ 51.59	$ 16.51
Total operating income (000s)	$ 7,524	$ 6,094	$ 1,828	$ 15,446

Total operating income in 2015 declined by 8% when compared to 2014 and declined by 29% in the final quarter of 2015 when compared to the same quarter of 2014. Per Boe, excluding hedging gains and losses, field operating netback in 2015 fell by an eye watering 59% in comparison to 2014 and by 57% in the final quarter of 2015. For 2015, year-over-year royalties, production and transportation costs per Boe each fell considerably, but these gains were insufficient to counter the effect of reduced commodity prices which saw the per-Boe realization fall by $18.84, or 50%, with the final quarter comparison being largely similar.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, amounted to $10.13 for 2015 and $11.43 for 2014, a reduction of 11%, and $8.82 for the final quarter of 2015 compared to $10.06 for the final quarter of 2014, a reduction of 12%. Comparing 2015 to 2014, all components of cash costs decreased on a per-Boe basis except for general and administrative costs. Although it is reasonable to expect future reductions in cash costs per commodity unit, they will not offset the effect of the commodity price collapse.

General and Administrative Costs

Total Costs	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period – before recoveries	$ 1,675	$ 1,581	$ 7,622	$ 5,956
Overhead recoveries	(420)	(498)	(2,121)	(2,144)
Charge for period – net of recoveries	$ 1,255	$ 1,083	$ 5,501	$ 3,812
Per Boe	$ 1.27	$ 1.16	$ 1.51	$ 1.50

Gross general and administrative costs for 2015 increased by 28% when compared to 2014 and for the final quarter of 2015 increased by 6% when compared to the final quarter of 2014. The increase in general and administrative costs is largely attributable to increases in personnel costs, including the timing of payout of prior year bonus amounts. For the full year, overhead recoveries decreased marginally as a result of lower field capital spending. For the final quarter, lower overhead recoveries corresponded to the capital program which involved outlays with a lower overhead recovery component.

On a per-Boe measure, net general and administrative costs in 2015 increased by 1% compared to 2014 and increased by 9% in the final quarter of 2015 compared to the same period in 2014, lower than the increase in net costs as production increased. General and administrative costs for the fourth and first quarters of a fiscal year tend to be higher due to the inclusion of certain costs specific to year end reporting.

Share-Based Compensation

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ 878	$ 756	$ 3,467	$ 2,192
Per Boe	$ 0.89	$ 0.81	$ 0.95	$ 0.86

Share-based compensation is a non-cash charge which reflects the estimated value of stock options issued to Storm's directors, officers and employees. Share-based compensation increased by 58% in 2015 compared to 2014 and increased by 16% in the final quarter of 2015 compared to the same quarter in 2014. The increase in share-based compensation is attributable to stock options granted during the year.

Depletion and Depreciation

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Depletion	$ 7,199	$ 8,965	$ 30,033	$ 25,869
Depreciation	1,108	1,155	4,550	3,623
Charge for period	$ 8,307	$ 10,120	$ 34,583	$ 29,492
Per Boe	$ 8.42	$ 10.81	$ 9.52	$ 11.58

Property and equipment are subject to depletion and depreciation charges. Depletion is calculated using unit-of-production methodology under which intangible 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 tangible 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.

Higher production volumes resulted in the total charge for depletion and depreciation increasing by 17% in 2015 compared to 2014. However, the charge fell by 18% in the final quarter of 2015 compared to the same quarter in 2014. The year-over-year per-Boe charge for depletion and depreciation fell by 18% in 2015 compared to 2014, and year over year by 22% in the final quarter of 2015, as the finding and development cost for proved plus probable reserves has declined, reflecting Storm's successful development program at Umbach, as well as the sale of higher cost Alberta properties in July 2015. Increased depreciation charges year over year corresponds to increased investment in facilities.

Exploration and Evaluation Costs Expensed

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ -	$ 1,152	$ 154	$ 1,427
Per Boe	$ -	$ 1.23	$ 0.04	$ 0.56

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, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ 87	$ 110	$ 441	$ 351
Per Boe	$ 0.09	$ 0.12	$ 0.12	$ 0.14

Accretion represents the time value increase for each period for the Company's decommissioning liability. The increased charge for accretion in 2015 compared to 2014 is due to continuing field investment and to changes in estimates of future costs and discount rates. The decreased charge in the final quarter of 2015 compared to the same quarter in 2014 is due to the reduction in the decommissioning liability as a result of the sale of Alberta properties in July 2015.

Interest and Finance Costs

(000's)	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Charge for period	$ 537	$ 470	$ 2,264	$ 1,532
Percentage of revenue from product sales	3.7%	1.7%	3.3%	1.6%
Per Boe	$ 0.54	$ 0.50	$ 0.62	$ 0.60

Compared to the prior year, interest costs in 2015 increased by 48% as a result of expanded bank borrowings used to fund development of the Company's growing production and asset base. For the final quarter of 2015, compared to the equivalent period in 2014, interest costs increased by 14%, lower than the annual increase, as a result of bank indebtedness being reduced by the equity issue and sale of the Alberta properties in June and July 2015, respectively.

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 from operations ratio.

Gain on Disposal of Investments

In 2014, the Company sold 2.0 million common shares of Chinook Energy Inc. ("Chinook") for proceeds of $3.8 million recognizing a gain of $1.5 million. There have been no further sales of Chinook common shares.

Unrealized Revaluation Loss on Investment

In 2015 the Company recognized a loss of $0.6 million representing the mark-to-market reduction in the carrying amount of the Company's investment in Chinook, as measured against the market value at the previous year end. The recognition of this unrealized loss is mandated by GAAP which requires that if a prolonged and significant decline in value emerges, the mark-to-market loss has to be included in the determination of income or loss for the reporting period. The decline in value of this investment corresponds to market conditions for junior exploration and development companies such as Chinook.

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 from each CGU, the recoverable amount being defined as the greater of its estimated value in use and its fair value less cost to sell. The assessment of the carrying amount of each of the Company's CGUs was 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, 2015. Continuing declines in commodity prices indicated potential impairment at Storm's key Umbach property. The assessment of the recoverable amount, as defined under IFRS, determined that there was no impairment at December 31, 2015.

In the fourth quarter of 2014, after review of various factors including future capital allocation and year-end external engineering reports, which included estimates of future cash flows and future prices, the Company reduced the carrying amount of the Alberta CGU by $22.7 million. The reduction in the carrying amount of the Alberta CGU at December 31, 2014 was determined using before tax future cash flows, discounted at a rate of 15% to 20% ("NPV15" and "NPV20") for the properties within the CGU which represented a multiple of approximately six times cash flow using current production and the forward strip for future commodity prices. The year-over-year reductions in discounted future cash flows relative to the carrying amount of this CGU on the Company's statement of financial position were due to commodity price declines coupled with increased repair and maintenance costs on properties since disposed of, as well as technical revisions to 2014 year-end reserves.

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 Disposal of Oil and Gas Properties

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). Disposals in 2014 were not significant.

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 Pool	As at December 31, 2015	Maximum Annual Deduction
Canadian oil and gas property expense	$ 45,000	10%
Canadian development expense	104,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	83,000	20% – 100%
Operating losses	171,000	100%
Other	5,000	20% – 100%
Total	$ 430,000	

Net Income (Loss)

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Net income (loss)	$ 1,850	$ (7,422)	$ (6,867)	$ 4,855
Per basic and diluted share	$ 0.02	$ (0.07)	$ (0.06)	$ 0.04

Other Comprehensive Income (Loss)

Other comprehensive income comprises net income (loss) for the period plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. For the year ended December 31, 2015, a loss of $110,000 (2014 – gain of $110,000) was recognized in other comprehensive income representing the reversal of prior mark-to-market gains in value of the investment in Chinook. There was no similar gain or loss in the final quarter of 2015: in the equivalent period of 2014 a prior period mark-to-market gain was reversed.

Listed Securities	Holding	Number of Shares(1)	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Chinook Energy Inc.	Common Shares	1,000,000	$ -	$ (780)	$ (110)	$ 110
Other comprehensive income (loss) for period			$ -	$ (780)	$ (110)	$ 110

(1) Shares owned at December 31, 2015.

Cash Flows from Operating Activities and Non-GAAP Funds from Operations

	Three Months to Dec. 31, 2015		Three Months to Dec. 31, 2014		Year Ended Dec. 31, 2015		Year Ended Dec. 31, 2014	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Cash from operating activities	$ 7,050	$0.06	$17,471	$0.15	$35,467	$0.31	$48,329	$0.44
Net change in non-cash working capital items	2,132	0.02	(3,579)	(0.03)	3,579	0.03	(2,917)	(0.03)
Non-GAAP funds from operations	$ 9,182	$0.08	$13,892	$0.12	$39,046	$0.34	$45,412	$0.41

The reconciling item between funds from operations and cash flows from operating activities is the change in non-cash operating working capital items as set out in Note 15 to the consolidated financial statements at December 31, 2015 and 2014.

Non-GAAP funds from operations for 2015 decreased by 14% from the prior year and by 34% when comparing the final quarters of 2015 and 2014. Again, production growth was insufficient to overcome commodity price collapse.

Non-GAAP funds from operations is not a measure recognized by GAAP, although it is widely used by investors, analysts and other financial statement users. It is also used by the Company's banking syndicate to determine debt-to-cash-flow ratios and other measures of credit worthiness and thus determines interest rates on borrowings. The most directly comparable measure under GAAP is cash flows from operating activities, as set out above.

Corporate Netbacks

($/Boe)	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Revenue from product sales	14.67	29.99	18.64	37.48
Realized hedging gains (losses)	4.20	0.52	4.20	(1.26)
Royalties	0.05	(3.69)	(0.82)	(5.16)
Production	(7.01)	(8.40)	(8.00)	(9.33)
Transportation	(0.79)	(1.91)	(1.13)	(1.80)
General and administrative	(1.27)	(1.16)	(1.51)	(1.50)
Interest and finance costs	(0.54)	(0.50)	(0.62)	(0.60)
Funds from operations	9.31	14.85	10.76	17.83
Share-based compensation	(0.89)	(0.81)	(0.95)	(0.86)
Depletion, depreciation and accretion	(8.51)	(10.93)	(9.64)	(11.72)
Exploration and evaluation costs expensed	-	(1.23)	(0.04)	(0.56)
Gain on disposal of investments	-	-	-	0.58
Unrealized revaluation loss on investments	(0.03)	-	(0.16)	-
Reduction of carrying amount of property and equipment	-	(24.26)	-	(8.91)
Loss on sale of oil and gas properties	(0.08)	-	(0.48)	(0.02)
Unrealized gain (loss) on commodity price contracts	2.08	14.45	(1.36)	5.56
Net income (loss) per Boe	1.88	(7.93)	(1.87)	1.90

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the beginning of 2014, Storm's bank facility amounted to $65.0 million. In May and November 2014, the facility was increased to $90.0 million and $130.0 million, respectively, in recognition of production and reserve growth at Umbach. In April 2015, the facility was again increased to $150.0 million. In July 2015, subsequent to the disposal of non-core assets in Alberta, the facility was reduced to $140.0 million, of which amount 41% was drawn at December 31, 2015. The facility is available until April 29, 2016, at which time the borrowing base amount will be reviewed. In the ordinary course, 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 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, 2015 debt including working capital deficiency amounted to $61.7 million and the facility credit limit was $140.0 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 2015, the Company spent $95.1 million (2014 - $106.6 million) on field operations almost exclusively to develop the high liquids content natural gas play at Umbach. Ten 100% working interest horizontal wells were drilled, 13 horizontal wells and one salt water disposal well were completed, and 12 horizontal wells were brought on production. Completed expansions of a compressor station at Umbach added compression capacity of 35 Mmcf per day, a condensate stabilizer and a fuel gas conditioning unit. In addition, a 15-kilometre pipeline was built to a third party natural gas processing plant. At December 31, 2015 eight wells were drilled awaiting tie-in, of which four were completed.

Major field capital outlays in 2015 include $52.5 million on drilling and completions and $36.1 million on facilities, equipping and tie-ins, all in the Umbach area.

In the final quarter of 2015, the Company drilled four 100% interest horizontal wells and completed and tied in the same number. The Company also purchased equipment in advance of the construction of a third compression facility in 2016 and acquired 11 sections of undeveloped land at Umbach.

In July 2015, the Company completed the disposition of largely crude oil properties in the Grande Prairie area of Alberta for net proceeds of $23.6 million.

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Land and lease	$ 235	$ 342	$ 956	$ 1,763
Drilling	7,954	4,240	20,946	37,620
Completions	14,478	8,149	31,562	30,469
Facilities, equipping and pipelines	3,958	7,488	36,064	34,351
Recompletions and workovers	(45)	-	1,093	2,328
Property and facility acquisitions	-	-	-	87,951
Property acquisition, adjustments, and administrative assets	37	(124)	64	-
Other	-	-	-	73
Total expenditures	$ 26,617	$ 20,095	$ 90,685	$ 194,555
Land acquisitions	4,381		4,414	
Proceeds on disposition of oil and gas properties	83	-	(23,590)	-
Net capital invested	$ 31,081	$ 20,095	$ 71,509	$ 194,555

Net capital investment was allocated as follows:

	Three Months to Dec. 31, 2015	Three Months to Dec. 31, 2014	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
Exploration and evaluation	$ 4,616	$ 637	$ 3,451	$ 80,684
Property and equipment	26,465	19,458	68,058	113,871
Total – net of dispositions	$ 31,081	$ 20,095	$ 71,509	$ 194,555

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, 2015 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 amount of the liability at December 31, 2015 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 the amount 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 2.25%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring 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.

Shareholders' Equity

Details of share issuances from inception to December 31, 2015 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
Total at December 31, 2015		119,467	$ 3.28	$ 391,916

(1) Before share issue costs.

On January 31, 2014, the Company issued 13,629,442 common shares at a fair value under IFRS of $4.25 per share, as partial consideration for the acquisition of two horizontal wells producing 359 Boe net per day and 29 sections of undeveloped land directly adjacent to Storm's 100% working interest lands in Umbach South. The total cost of the acquisition was approximately $87.9 million including $30.0 million in cash.

In February 2014, the Company issued 7,250,000 common shares pursuant to a bought deal financing at a price of $4.10 per common share for gross proceeds of $29,725,000. At the same time, the Company issued to certain directors, officers and employees of the Company 1,250,000 common shares pursuant to a non-brokered financing at a price of $4.10 per common share for gross proceeds of $5,125,000. Both of these financings closed on February 14, 2014. Net proceeds received totaled $33.0 million.

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 $34.2 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.

Issued and outstanding common shares at December 31, 2015 totaled 119,466,978 and at February 25, 2016, the date of this MD&A, totaled 119,608,478.

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 agreement; and
- hedging 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, not including operating costs, totaling approximately $3.0 million over the term of the lease. Current monthly operating costs amount to $28,600. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $164.2 million over the period to December 31, 2020.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended December 31, 2015 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 first quarter of 2014 to the final quarter of 2015 have been affected by one dominant trend – production growth has been insufficient to offset the relentless fall in commodity prices.

				2015				2014
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production revenue ($000s)[1]	18,624	18,256	20,236	25,871	28,556	24,131	20,202	19,393
Non-GAAP funds from operations ($000s)[2]	9,182	7,982	8,170	13,712	13,892	11,784	11,076	8,660
Per share								
- basic ($)	0.08	0.07	0.07	0.12	0.13	0.11	0.10	0.09
- diluted ($)	0.08	0.07	0.07	0.12	0.12	0.11	0.10	0.08
Net income (loss) ($000s)	1,850	(961)	(4,191)	(3,565)	(7,422)	5,473	6,598	206
Per share								
- basic ($)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05	0.06	0.00
- diluted ($)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05	0.06	0.00
Net capital expenditures ($000s)	31,081	(4,116)[4]	8,864	35,680	20,095	30,426	33,640	110,394
Average daily production - Boe	10,730	9,654	9,657	9,776	10,173	7,160	5,462	5,068
Net debt ($000s)[3]	61,721	39,994	28,051	85,098	63,080	56,157	41,837	22,176

(1) Includes realized hedging gains and losses.
(2) See Non-GAAP Measurements on page 37 of this MD&A.
(3) Includes working capital deficiency and excludes the fair value of commodity price contracts.
(4) Net of property disposition for proceeds of $23.6 million.

SELECTED ANNUAL FINANCIAL INFORMATION

	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Production revenue ($000s)[1]	82,987	92,282	49,542
Funds from operations ($000s)	39,046	45,412	21,949
Per share – basic ($)	0.34	0.42	0.30
Per share – diluted ($)	0.34	0.41	0.30
Net income (loss) ($000s)	(6,867)	4,855	(26,203)
Per share – basic ($)	(0.06)	0.04	(0.36)
Per share – diluted ($)	(0.06)	0.04	(0.36)
Total assets ($000s)	440,658	418,568	250,550
Debt including working capital deficiency ($000s)	61,721	63,080	12,059
Average daily production (Boe)	9,956	6,980	3,637
Field netback ($/Boe)[1]	12.89	19.93	20.40

(1) Includes hedging gains and losses.

Share Trading

Set out below is share trading activity for Storm for 2015 and 2014.

	2015					2014				
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	5.08	5.05	4.89	4.66	5.08	4.95	5.75	6.10	6.16	6.16
Low ($)	3.02	4.10	3.25	2.86	2.86	3.82	4.66	4.30	3.37	3.37
Close ($)	4.60	4.75	4.22	3.62	3.62	4.71	5.28	5.77	4.14	4.14
Volume traded (000s)	14,911	11,913	12,827	8,080	47,731	17,385	19,825	23,486	26,556	87,253
Value traded ($000s)	61,281	55,530	52,877	30,544	200,232	76,088	103,659	124,400	132,420	436,567
Weighted average trading price ($)	4.11	4.66	4.12	3.78	4.20	4.38	5.23	5.30	4.99	5.00

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, 2015 and 2014 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. Uncertainty of measurement related to each of the following items will vary: further, the level of uncertainty may change between reporting periods. Variations between amounts estimated and actual results subsequently realized 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, NGL and crude oil 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. Reserve estimates are prepared 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.

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 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 may 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.

Exploration and Evaluation Assets

Costs incurred by the Company in the initial 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 residual balance of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods.

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.

Property and equipment are 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. 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, 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. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices;
- future production volumes, production volumes by commodity and production declines;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific projects, activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition, construction and entry in service;
- future earnings or losses, including per-share amounts;
- future non-GAAP funds from operations and future cash flows, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future sources of funding for capital programs and future availability of such sources;
- development plans;
- estimates regarding the carrying amount of exploration and evaluation costs;
- estimates regarding the carrying amount of property and equipment;
- 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 tax liabilities and future 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 royalties, transportation costs, operating costs, interest and general and administrative costs in total and by commodity unit;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas;
- 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;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations; 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 Gain (Loss) 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"; "Gain on Disposal of Investments"; "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)"; "Other Comprehensive Income (Loss)"; "Cash Flows from Operating Activities"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Shareholders' Equity"; "Contractual Obligations"; industry conditions including commodity prices, capacity constraints and access to processing facilities and to market for production, volatility of commodity prices, 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. 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, "funds from operations", "funds from operations per share", "debt including working capital deficiency", "netbacks", "field netbacks", "corporate netbacks", "field operating netback", "field operating netback before hedging", "total operating income", "cash costs", and measurements "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. In particular, funds from operations is not intended to represent, or be equivalent to, cash flow from operating activities calculated in accordance with GAAP, which is measured on the Company's consolidated statements of cash flows. Funds from operations and other non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, analysts and other parties. Funds from operations is also used by lenders to measure compliance with debt covenants and thus set interest costs. Reference is made to the discussion in this MD&A under "Non-GAAP Funds from Operations and Funds from Operations per Share" and to "Cash Flows from Operating Activities".

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.

Exploration and Development

Storm's exploration and development 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.

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 cash 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 is ineffective 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.

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 and 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 months. 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 exploration and 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 hedging agreements 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 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 results, 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 exploration and development efforts 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.

Storm's contracted gas processing capacity at third party facilities was approximately 89% of total raw gas production during December 2015 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 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.

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 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. The Company measures debt levels against current or near-term cash flows. If the debt-to-cash-flow ratio becomes unacceptably high, capital programs will be postponed, assets sold 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 cash flows 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 owned or third party. 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.

Storm has contracted pipeline transportation capacity for approximately 60 Mmcf per day of natural gas sales volumes in the first quarter of 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 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 cash 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 cash 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 cash 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 royalty structure in Alberta has recently changed; however, detailed information regarding future royalty rates is not yet available. The same concern applies to the Federal government. Federal corporate tax rates are low by international standards and are thus vulnerable to upward adjustment.

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 government, 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

Accounting Changes

Future Accounting Policies

Leases

In January 2016 the IASB issued IFRS 16 Leases, which requires lessees to recognize assets and liabilities for most leases. The standard replaces IAS17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Storm does not employ hedge accounting for risk management contracts currently in place. This standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

The Company is currently evaluating the effect of these standards on Storm's financial statements.

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 Canadian Institute of Chartered Accountants ("CICA"). 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

February 25, 2016

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, 2015 and 2014, and the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows 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 the accounting policies used and the reasonableness of the 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, 2015 and 2014, 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

February 25, 2016

Consolidated Statements of Financial Position

(Canadian $000s)	December 31, 2015	December 31, 2014
ASSETS		
Current		
Accounts receivable (Note 12)	$ 9,635	$ 9,475
Prepaids and deposits	728	905
Fair value of commodity price contracts (Note 12)	7,984	12,920
	18,347	23,300
Exploration and evaluation (Note 4)	119,356	126,805
Property and equipment (Note 5)	302,955	268,463
	$ 440,658	$ 418,568
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 15,007	$ 27,430
	15,007	27,430
Bank indebtedness (Note 6)	57,077	46,030
Decommissioning liability (Note 7)	16,016	23,553
	88,100	97,013
Shareholders' equity		
Share capital (Note 9)	385,766	351,161
Contributed surplus (Note 10)	6,738	3,363
Deficit	(39,946)	(33,079)
Accumulated other comprehensive income	-	110
	352,558	321,555
Commitments (Note 16)		
	$ 440,658	$ 418,568

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director

James K. Wi

Director

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

(Canadian $000s except per-share amounts)	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenue		
Revenue from product sales	$ 67,736	$ 95,480
Royalties	(2,982)	(13,151)
Net revenue	$ 64,754	$ 82,329
Realized gain (loss) on commodity price contracts (Note 12)	15,251	(3,198)
Unrealized gain (loss) on commodity price contracts (Note 12)	(4,936)	14,168
Income from hedging activities	$ 10,315	$ 10,970
Expenses		
Production	29,076	23,781
Transportation	4,118	4,594
General and administrative (Notes 14 and 16)	5,501	3,812
Share-based compensation (Note 10)	3,467	2,192
Depletion and depreciation (Note 5)	34,583	29,492
Reduction in carrying amount of property and equipment (Note 5)	-	22,700
Exploration and evaluation costs expensed (Note 4)	154	1,427
Accretion (Note 7)	441	351
	77,340	88,349
Income (loss) before the following:	(2,271)	4,950
Interest and finance costs	(2,264)	(1,532)
Gain on disposal of investments (Note 12)	-	1,486
Unrealized revaluation loss on investments (Note 12)	(580)	-
Loss on sale of oil and gas properties (Note 5)	(1,752)	(49)
Net income (loss) for the year	(6,867)	4,855
Other comprehensive income (loss)		
Reversal of prior year unrealized (gain) loss on investments	(110)	110
Comprehensive income (loss) for the year	$ (6,977)	$ 4,965
Net income (loss) per share (Note 11)		
- basic	$ (0.06)	$ 0.04
- diluted	$ (0.06)	$ 0.04

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(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 9)	36,662	-	-	-	36,662
Share issue costs (Note 9)	(2,149)	-	-	-	(2,149)
Share-based compensation (Note 10)	-	3,467	-	-	3,467
Share-based compensation on options exercised (Note 9)	92	(92)	-	-	-
Reversal of prior period unrealized gain on Investments (Note 12)	-	-	-	(110)	(110)
Balance, end of year	$ 385,766	$ 6,738	$ (39,946)	$ -	$ 352,558

(Canadian $000s)				Year Ended December 31, 2014	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of year	$ 252,837	$ 2,969	$ (37,934)	$ -	$ 217,872
Net income for the year	-	-	4,855	-	4,855
Issue of common shares (Note 9)	98,355	-	-	-	98,355
Share issue costs (Note 9)	(1,829)	-	-	-	(1,829)
Share-based compensation (Note 10)	-	2,192	-	-	2,192
Share-based compensation on options exercised (Note 10)	1,798	(1,798)	-	-	-
Reversal of prior period unrealized loss on investments (Note 12)	-	-	-	110	110
Balance, end of year	$ 351,161	$ 3,363	$ (33,079)	$ 110	$ 321,555

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating activities		
Net income (loss) for the year	$ (6,867)	$ 4,855
Non-cash items:		
Share-based compensation (Note 10)	3,467	2,192
Depletion, depreciation and accretion (Notes 5 and 7)	35,024	29,843
Reduction in carrying amount of property and equipment (Note 5)	-	22,700
Exploration and evaluation costs expensed (Note 4)	154	1,427
Gain on disposal of investments (Note 12)	-	(1,486)
Unrealized revaluation loss on investments (Note 12)	580	-
Loss on sale of oil and gas properties (Note 5)	1,752	49
Unrealized loss (gain) on commodity price contracts (Note 12)	4,936	(14,168)
Net change in non-cash working capital items (Note 15)	(3,579)	2,917
	35,467	48,329
Financing activities		
Proceeds from issue of common shares – net of expenses (Note 9)	34,510	38,601
Increase in bank indebtedness	11,047	35,403
	45,557	74,004
Investing activities		
Additions to exploration and evaluation assets (Note 4)	(5,350)	(1,754)
Additions to property and equipment (Note 5)	(89,749)	(104,850)
Cash portion of acquisitions of exploration and evaluation assets and property and equipment (Notes 4 and 5)	-	(30,026)
Proceeds on sale of investments (Note 12)	-	3,806
Proceeds on disposal of exploration and evaluation assets (Notes 4 and 5)	1,899	-
Proceeds on disposal of property and equipment (Note 5)	21,691	-
Net change in non-cash working capital items (Note 15)	(9,515)	10,491
	(81,024)	(122,333)
Change in cash during the year	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

Years ended December 31, 2015 and 2014

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 in the provinces of Alberta and 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.

2. BASIS OF PRESENTATION

Statement of Compliance

The financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued and amended from time to time by the International Accounting Standards Board ("IASB") and adopted by CPA Canada. Certain prior year balances have been reclassified to match the current year presentation.

These financial statements were authorized for issue by the Board of Directors on February 25, 2016.

Basis of Measurement

The Company's financial statements have been prepared on a going concern basis consistent with prior years, under the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 12.

Future Accounting Policies

Leases

In January 2016 the IASB issued IFRS 16 Leases which requires lessees to recognize assets and liabilities for most leases. This standard replaces IAS17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

In November 2009 the IASB issued IFRS 9 Financial Instruments which is intended to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Storm does not employ hedge accounting for risk management contracts currently in place. This standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

The Company is currently evaluating the effect of these standards on Storm's financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

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. These 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.

Business Combinations

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. 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.

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 exploration and evaluation activities are also included. Costs incurred in advance of land acquisition are charged to the consolidated statement of income (loss); however, all other costs, including directly attributable general and administrative costs, are added to E&E assets.

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). 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 transferred to property and equipment. If, at any time, it is determined that the Company has no future exploration 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).

No depletion or depreciation is provided for exploration and evaluation assets.

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.

See Note 5.

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 charged as accretion expense 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 and that portion of costs that is greater than or less than the liability is reflected in the consolidated statement of income (loss).

Revenue Recognition

Revenue associated with the sale of crude oil, natural gas 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.

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 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.

Trade receivables, loans and other receivables

Trade receivables, loans and other receivables which are non-derivative financial assets that have fixed or determinable payment terms and are not quoted in an active market, are classified as loans and receivables. They are included in current assets, except for maturities greater than 12 months after the reporting date, which are classified as non-current assets. The Company's loans and receivables comprise accounts receivable relating to the Company's operations and capital programs.

Loans and receivables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment.

A provision for impairment of trade receivables 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 receivables. 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.

Investments

The Company's investments in publicly-listed companies are classified as available-for-sale investments.

Investments in publicly-listed companies are recognized initially at fair value and subsequently are fair valued using the closing price on the reporting date of the financial statement. Gains or losses arising from changes in fair value are recognized in other comprehensive income (loss).

Available-for-sale investments are classified as current assets, if management expects to dispose of the investments within twelve months. Such investments are deemed to be impaired when there is evidence of a significant and prolonged decline in value. When an available-for-sale investment is sold or deemed to be impaired, the accumulated gains or losses are transferred from accumulated other comprehensive income to the consolidated statement of income (loss). Subsequent gains are recorded in other comprehensive income (loss) while subsequent losses are recorded in the consolidated statement of income (loss).

The Company's sole investment in publicly listed companies is an investment in common shares of Chinook Energy Inc. ("Chinook"). This investment is not a material asset and is included with accounts receivable on the Company's consolidated statement of changes in financial position.

Derivative 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 recorded on the consolidated statement of financial position at fair value.

Accounts payable and accrued liabilities

Accounts payable and accrued liabilities are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers or under joint ventures or similar arrangements. Accounts payable and accrued liabilities are classified as current liabilities if payment is due within one year or less.

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.

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

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.

Use of Judgments and Estimates in Application of Accounting Policies

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 as follows:

Note 4 - 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 review is also 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).

Note 5

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.

Note 7 - 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.

Note 8 – 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.

Note 10 – 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.

Note 12 – 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 controls that impede the efficiency of the market.

4. EXPLORATION AND EVALUATION

	Year Ended December 31, 2015	Year Ended December 31, 2014
Balance, beginning of year	$ 126,805	$ 87,396
Acquisitions	-	78,930
Additions	5,350	1,754
Exploration and evaluation expenditures expensed	(154)	(1,427)
Future decommissioning costs	313	3,476
Disposals	(2,843)	-
Transfer to property and equipment	(10,115)	(43,324)
Balance, end of year	$ 119,356	$ 126,805

In the first quarter of 2014, the Company acquired two producing horizontal wells and 29 sections of undeveloped land at Umbach South for approximately $88.0 million, with $79.0 million allocated to the purchase of exploration and evaluation assets and undeveloped land and $9.0 million to the purchase of property and equipment. This transaction did not constitute a business combination under IFRS.

At December 31, 2015 and 2014 management determined that no indicators of impairment existed on the Company's exploration and evaluation assets; therefore, no impairment test was performed.

5. PROPERTY AND EQUIPMENT

	Year Ended December 31, 2015	Year Ended December 31, 2014
Cost		
Balance, beginning of year	$ 379,207	$ 211,024
Acquisitions	-	8,972
Additions	89,749	104,850
Future decommissioning costs	1,831	11,037
Disposals	(91,121)	-
Transfer from exploration and evaluation assets	10,115	43,324
Balance, end of year	$ 389,781	$ 379,207
Accumulated depletion and depreciation		
Balance, beginning of year	$ (110,744)	$ (58,552)
Depletion and depreciation	(34,583)	(29,492)
Disposals	58,501	-
Reduction in carrying amount of property and equipment	-	(22,700)
Balance, end of year	$ (86,826)	$ (110,744)
Net book value, beginning of year	$ 268,463	$ 152,472
Net book value, end of year	$ 302,955	$ 268,463

In July 2015, the Company sold its Grande Prairie oil properties for net proceeds of approximately $23.6 million. The resulting loss of $1.75 million was recorded on the statement of income (loss) and comprehensive income (loss).

Future development costs for the year ended December 31, 2015 of $543.3 million (December 31, 2014 - $606.6 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, 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 crude oil and natural gas. This was not considered to be an indicator of impairment for the other much smaller CGUs, whose values are more dependent on land values than commodity prices.

An impairment is recognized if the carrying value of a CGU exceeds the recoverable amount for that CGU. 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.

An impairment test was performed at December 31, 2015 using a pre-tax discount rate of 10% (this discount rate gives recognition to the quality, scale and repeatability of the Umbach project) and the following forward commodity price estimates:

Year	AECO Gas (Cdn$/Mmbtu)[(1)]	Edmonton Light Crude Oil (Cdn$/Bbl)[(1)]
2016	2.71	55.64
2017	3.27	68.33
2018	3.74	78.23
2019	3.87	81.22
2020	4.05	85.06
2021	4.21	88.71
2022	4.49	91.54
2023	4.58	94.37
2024	4.67	96.26
2025	4.76	98.18
Thereafter the prices escalate by 2% per year		

(1) Source: InSite Petroleum Consultants Ltd. price forecasts effective January 1, 2016.

The inputs used in this assessment were determined to be Level 3 (Note 12) as they are not based on observable market data.

The Company has determined that there was no impairment to property and equipment at December 31, 2015. Increasing the discount rate to 15% would not have resulted in an impairment charge.

At December 31, 2014, the most important indicator of impairment was also a reduction in forecasted future commodity prices. The carrying amount of those CGUs where indicators existed was compared to the estimated present value of pre-tax cash flows from proved plus probable reserves, as determined by the Company's independent engineers. The discount rates used in the determination of present value were 15% to 20% for the properties in the CGUs subject to assessment, which also represented a multiple of approximately six times estimated future cash flow using current production and the forward strip for future commodity prices. The comparison of the 2014 year-end value of reserves indicated that the carrying amounts of the Company's Alberta oil and gas CGU exceeded its fair value by $22.7 million. Property and equipment on the Company's consolidated statement of financial position at December 31, 2014 was reduced by this amount with the reduction being included in the consolidated statement of income (loss). These properties were sold in 2015.

6. BANK INDEBTEDNESS

As at December 31, 2015, the Company had an extendible revolving bank facility in the amount of $140.0 million (December 31, 2014 – $130.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 29, 2016, at which time the borrowing base amount will be reviewed and the Company has 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. At December 31, 2015, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency not exceed the facility amount.

The Company has issued letters of credit in the amount of $3.7 million in support of future gas transportation and processing obligations. (Note 16)

7. 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 $25.6 million (December 31, 2014 - $37.3 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 2.25% (2014 – 2.33%) and an inflation rate of 1.9% (2014 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $16.0 million.

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
Balance, beginning of year	$ 23,553	$ 8,689
Obligations incurred	1,961	3,797
Obligations acquired	-	710
Obligations disposed	(10,122)	-
Obligations settled	-	(34)
Change in rate estimates(1)	(68)	6,029
Change in cost estimates(2)	251	4,011
Accretion expense	441	351
Balance, end of year	$ 16,016	$ 23,553

(1) Relates to changes in the inflation rate and discount rate in 2014 and 2015.
(2) Cost estimates were adjusted based on actual costs for abandonments and reclamations.

8. 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 and property and equipment of approximately $259.0 million as well as non-capital losses of approximately $171.0 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, 2015	Year Ended December 31, 2014
Net income (loss) for the year	$ (6,867)	$ 4,855
Statutory combined federal and provincial income tax rate	26.5%	25%
Expected income tax expense (recovery)	$ (1,820)	$ 1,214
Add (deduct) the income tax effect of:		
Share-based compensation	919	548
Change in unrecorded deferred income tax asset	1,264	(1,652)
Change in enacted rate	(178)	-
Change in estimated tax pool balances	(98)	(47)
Other	(87)	(63)
Deferred income taxes	$ -	$ -

The components of the unrecorded deferred income tax assets and liabilities are as follows:

	As at December 31, 2015	As at December 31, 2014
Deferred tax assets:		
Non-capital losses	$ 45,474	$ 34,310
Decommissioning liability	4,244	5,888
Share issue costs	1,137	934
Investment	231	131
	$ 51,086	$ 41,263
Deferred tax liabilities:		
Property and equipment	$ (33,999)	$ (25,327)
Fair value of commodity price contracts	(2,116)	(3,542)
	$ (36,115)	$ (28,869)

9. 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, 2013	87,483	$ 252,837
Shares issued pursuant to Umbach acquisition(1)	13,629	57,925
Shares issued pursuant to private placement(2)	8,500	34,850
Share issue costs(2)	-	(1,829)
Shares issued on stock option exercises(3)	1,710	7,378
Balance as at December 31, 2014	111,322	$ 351,161
Shares issued pursuant to private placement(4)	8,000	36,400
Share issue costs(4)	-	(2,149)
Shares issued on stock option exercises (5)	145	354
Balance as at December 31, 2015	119,467	$ 385,766

(1) On January 31, 2014 the Company issued 13,629,442 common shares, with a deemed value of $4.25 per common share, for a total amount of $57.9 million, and paid cash of approximately $30.0 million to acquire undeveloped land and natural gas wells in the Umbach area of northeast British Columbia. (Note 4)

(2) On February 14, 2014 the Company issued, under private placement agreements, 8,500,000 common shares at a price of $4.10 per common share for proceeds of approximately $34.9 million before issue costs of approximately $1.8 million.

(3) During 2014, 1,709,666 common shares were issued upon the exercise of a like amount of stock options for proceeds of approximately $5.5 million. Related prior period share-based compensation of $1.8 million was transferred to share capital from contributed surplus.

(4) 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.

(5) 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.

10. 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, employees and consultants. 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, 2015 a total of 11,946,697 common shares were available for issuance. Options in respect of 7,752,834 common shares were issued, all of which are unexercised, and options remained in respect of 4,193,863 common shares which were available for further grants under the stock option plan.

At February 25, 2016, the date of this report, 11,960,847 common shares are available for issuance and options in respect of 7,611,334 common shares have been issued, leaving options in respect of 4,349,513 common shares available for further grants.

Details of the options outstanding at December 31, 2015 and December 31, 2014 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2013	3,897	$ 2.47
Granted during the year	3,770	$ 4.52
Exercised during the year	(1,710)	$ 3.26
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
Number exercisable at December 31, 2015	2,804	$ 3.06

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	2,002	0.9	$ 1.83	1,507	$ 1.85
$2.64 - $3.95	1,941	3.9	$ 3.34	40	$ 3.04
$3.96 - $5.20	3,810	2.6	$ 4.52	1,257	$ 4.52
Total	7,753	2.5	$ 3.53	2,804	$ 3.06

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, 2015 of $1.33 per share (2014 - $1.88 per share) include the following:

	2015	2014
Share price	$3.35 - $4.71	$4.31 - $5.20
Exercise price	$3.35 - $4.71	$4.31 - $5.20
Volatility	53%	54% - 56%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Dividends	-	-
Risk-free interest rate	0.4% - 0.7%	1.2% - 1.4%

Share-based compensation expense of $3.5 million was charged to the consolidated statement of income (loss) during the year ended December 31, 2015 (2014 - $2.2 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.

11. NET INCOME (LOSS) PER SHARE

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

	Year Ended December 31, 2015	Year Ended December 31, 2014
Net income (loss) for the year	$ (6,867)	$ 4,855
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	111,322	87,483
Effect of shares issued	4,499	20,689
Weighted average number of common shares outstanding – basic	115,821	108,172
Effect of outstanding options	-	1,809
Weighted average number of common shares outstanding - diluted	115,821	109,981
Net income (loss) per share		
- basic	$ (0.06)	$ 0.04
- diluted	$ (0.06)	$ 0.04

At December 31, 2015, all outstanding stock options were considered anti-dilutive as the Company was in a loss position. For 2014, 62,000 stock options were excluded from the calculation of dilutive shares as they were anti-dilutive.

12. FINANCIAL INSTRUMENTS

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 fair value of the Company's investment in Chinook, included with accounts receivable, is determined with reference to published share prices and is therefore classified as a Level 1 financial instrument. At December 31, 2015, the Company's investment in Chinook is carried at the fair value of $0.6 million (December 31, 2014 - $1.3 million).

In 2014 the Company sold 2.0 million shares of Chinook for net proceeds of $3.8 million and realized a gain of $1.5 million measured against the carrying amount at December 31, 2013.

The fair value of the Company's commodity 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 has no Level 3 financial instruments.

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. The maximum exposure to credit risk at December 31, 2015 is as follows:

	Carrying Amount as at December 31, 2015
Accounts receivable	$ 9,635
Fair value of commodity price contracts	7,984
Total	$ 17,619

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 contracts

The Company enters into derivative contracts with counterparties with an acceptable credit rating and with a demonstrated capability to execute such contracts. The contracts are short term and individually, and in aggregate, are subject to the limitations established by the Board of Directors and 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. The Company's production is sold to organizations whose credit worthiness is assessable from publicly available information. 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. The Company does not typically obtain collateral from joint venture partners.

No default on outstanding receivables is anticipated as none of the Company's outstanding receivable balance is considered past due at December 31, 2015.

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;
- prices of listed securities;
- interest rates; and
- foreign exchange rates.

Commodity prices

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 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 enters into contracts which may involve financial instruments, in order to reduce the fluctuation in production revenue by fixing prices of future deliveries of crude oil and natural gas and thus provide 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, 2015, part of its 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 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 of $8.0 million (December 31, 2014 – $12.9 million) is included in current assets. For the year ended December 31, 2015, this resulted in an unrealized mark-to-market loss of $4.9 million (2014 – gain of $14.2 million) when measured against the fair market value at the end of the preceding reporting period.

Period Hedged	Daily Volume	Average Price
Crude Oil Collar		
Jan – Dec 2016	500 Bbls	$75.00 - $90.75 Cdn$/Bbl
Natural Gas Swaps		
Q1 – 2016	5,000 GJ	AECO Cdn$3.06/GJ
Jan – Dec 2016	20,000 GJ	AECO Cdn$2.98/GJ
Natural Gas Differential Swaps		
Jan – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Jan – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

During 2015, the Company realized gains from commodity price contracts in place in the amount of $15.3 million (2014 – losses of $3.2 million).

Prices of listed securities

The value of the investment in Chinook held by the Company is affected by price fluctuations as the shares of Chinook are listed on the Toronto Stock Exchange.

Interest rates

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 exchange rates

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 opera tions 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, 2015, the estimated after-tax effect that changes in certain factors would have on net income and income per share is set out below:

		2015
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI[(1)]	$ 750,000	$ 0.01
$0.10/Mcf change in the price of natural gas	$ 1,780,000	$ 0.02
1% change in the interest rate	$ 510,000	$ -

(1) A portion of the Company's 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.

13. CAPITAL MANAGEMENT

The Company's capital structure is comprised of 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.

14. 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, 2015	Year Ended December 31, 2014
Salaries and short-term benefits	$ 2,465	$ 1,340
Share-based compensation	1,370	877
	$ 3,835	$ 2,217

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2015	Year Ended December 31, 2014
Accounts receivable	$ (849)	$ (2,020)
Prepaids and deposits	177	112
Accounts payable and accrued liabilities	(12,422)	15,316
Change in non-cash working capital	$ (13,094)	$ 13,408
Relating to:		
Operating activities	$ (3,579)	$ 2,917
Investing activities	(9,515)	10,491
	$ (13,094)	$ 13,408
Interest paid during the year	$ 2,023	$ 1,153
Income taxes paid during the year	$ -	$ -

16. COMMITMENTS

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

	2016	2017	2018	2019	2020	Total
Office lease	$ 943	$ 943	$ 708	$ -	$ -	$ 2,594
Natural gas sales commitments	43,434	42,187	36,777	22,187	19,630	164,215
Total	$ 44,377	$ 43,130	$ 37,485	$ 22,187	$ 19,630	$ 166,809

In 2015 the Company made office lease payments of approximately $928,000 (2014 - $912,000) 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
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
Mbbls	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbbls	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
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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