STORM RESOURCES

2014 YEAR-END REPORT

ANNUAL MEETING

The Annual General Meeting of shareholders will be held at 3:30 p.m. on Thursday, May 14, 2015 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$, except volumetric and per-share amounts	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Year Ended December 31, 2014	Year Ended December 31, 2013
FINANCIAL				
Revenue from product sales	28,070	15,380	95,480	49,578
Funds from operations(1)	13,892	7,501	45,412	21,949
Per share - basic ($)	0.13	0.09	0.42	0.30
Per share - diluted ($)	0.12	0.09	0.41	0.30
Net income (loss)	(7,422)	(25,174)	4,855	(26,203)
Per share - basic ($)	(0.07)	(0.34)	0.04	(0.36)
Per share - diluted ($)	(0.07)	(0.34)	0.04	(0.36)
Operations capital expenditures	20,219	11,380	106,604	67,410
Land and property acquisitions/dispositions	(124)	-	87,951	(14,966)
Debt including working capital deficiency	63,080	12,059	63,080	12,059
Common shares (000s)				
Weighted average - basic	111,305	81,994	108,172	73,391
Weighted average - diluted	112,850	81,994	109,981	73,391
Outstanding end of period – basic	111,322	87,483	111,322	87,483
OPERATIONS				
Revenue (Cdn$ per Boe)	29.99	35.02	37.48	37.34
Royalties (Cdn$ per Boe)	(3.69)	(2.65)	(5.16)	(4.55)
Production (Cdn$ per Boe)	(8.40)	(9.73)	(9.33)	(10.86)
Transportation (Cdn$ per Boe)	(1.91)	(1.82)	(1.80)	(1.50)
Field operating netback	15.99	20.82	21.19	20.43
Hedging gains (losses) (Cdn$ per Boe)	0.52	0.09	(1.26)	(0.03)
General and administrative (Cdn$ per Boe)	(1.16)	(3.25)	(1.50)	(2.98)
Interest (Cdn$ per Boe)	(0.50)	(0.58)	(0.60)	(0.90)
Funds from operations netback (Cdn$ per Boe)	14.85	17.10	17.83	16.52
Barrels of oil equivalent per day (6:1)	10,173	4,773	6,980	3,637
Gas Production				
Thousand cubic feet per day	49,094	21,898	33,067	15,843
Price (Cdn$ per Mcf)	3.85	3.88	4.58	3.63
NGL production				
Barrels per day	1,605	695	1,064	512
Price (Cdn$ per barrel)	56.15	70.10	69.90	0.29
Oil Production				
Barrels per day	385	428	405	485
Price (Cdn$ per barrel)	68.01	78.47	88.10	87.16
Wells drilled				
Gross	2.0	1.0	17.0	9.0
Net	2.0	1.0	17.0	8.6

(1) Funds from operations, funds from operations per share and funds from operations netback are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 19 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 30 of the attached MD&A.

PRESIDENT'S MESSAGE

2014 FOURTH QUARTER AND YEAR-END HIGHLIGHTS

- In 2014, significant per-share growth in production and reserves was achieved and material improvements were realized in controllable cash costs and the cost of reserve additions.
- Production for the year averaged 6,980 Boe per day (21% oil plus NGL), a per-share increase of 51% from 2013 (notable given the 28% increase in shares outstanding). Fourth quarter production was 10,173 Boe per day (20% oil plus NGL), an increase of 69% on a per-share basis from the previous year. The increase was the result of growth at Umbach where fourth quarter production was 8,775 Boe per day, an increase of 169% from 3,262 Boe per day in the fourth quarter of 2013.
- NGL production was 1,605 barrels per day in the fourth quarter, year-over-year growth of 131%. The increase was the result of production growth from the liquids-rich Montney formation at Umbach where NGL recovery was 35 barrels per Mmcf sales in the fourth quarter. With approximately 60% of the NGL mix being condensate plus pentanes, the NGL price of $56.15 per barrel was 74% of the average Edmonton light oil price.
- Activity during 2014 was focused at Umbach, where 16 Montney horizontal wells (16.0 net) plus one Montney vertical delineation well (1.0 net) were drilled, 13 horizontal wells (12.6 net) were completed, 10 horizontal wells (9.6 net) began producing, and a 100% working interest field compression facility was started up in August. In the fourth quarter, two Montney horizontal wells (2.0 net) were drilled, four Montney horizontal wells (4.0 net) were completed and three Montney horizontal wells (3.0 net) began producing.
- For the 2014 Montney horizontal wells at Umbach, calendar day rates (including downtime) over the first 90 days averaged 4.8 Mmcf per day gross raw gas (865 Boe per day sales), an improvement of 37% from the average 2013 horizontal well.
- Both operated facilities at Umbach have been full since mid-September and there is currently an inventory of 11 horizontal wells (11.0 net) that have not started producing which includes four completed horizontal wells. In addition, two more horizontal wells (2.0 net) remain to be drilled in the first quarter. Storm will achieve 2015 production guidance with forecast production from these horizontal wells.
- Funds from operations for the year totaled $45.4 million, or $0.42 per share, an increase of 40% on a per-share basis from the previous year. Funds from operations in the fourth quarter was $13.9 million, or $0.13 per basic share, an increase of 44% from the prior year.
- The funds from operations netback for the year was $17.83 per Boe, a year-over-year increase of 8% which was primarily the result of a decline in operating costs and cash G&A totaling $3.01 per Boe that was partially offset by an increased hedging loss of $1.23 per Boe.
- Controllable cash costs (operating, transportation, cash G&A, interest expense) were $13.23 per Boe in 2014, a year-over-year decrease of 19%. Controllable cash costs showed further improvement to average $11.97 per Boe in the fourth quarter. Cash G&A was $1.50 per Boe in 2014, a year-over-year decrease of 50%. Operating costs for the year decreased by 14% to average $9.33 per Boe and further improved to $8.40 per Boe in the fourth quarter.
- Net income for the year was $4.9 million, or $0.04 per share, a significant improvement when compared to the loss of $26.2 million in the previous year. This included a $22.7 million reduction in the carrying amount of the Grande Prairie properties which was partially offset by a $14.2 million unrealized gain on commodity price hedges.
- Capital investment was focused on the Umbach area and totaled $194.5 million for the year which included $88.0 million to acquire a 100% working interest in 29 sections of land at Umbach, $34.3 million for infrastructure and $68.1 million for drilling and completions.

- Cost of adding production during 2014 was approximately $16,400 per Boe per day using 2014 operations capital investment of $106.6 million and average fourth quarter production of 6,520 Boe per day from wells that started production in 2014 (excludes 350 Boe per day acquired in January 2014).

- Operating income for the year, being net income adjusted for impairment charges and unrealized hedging gains, was $13.4 million, or $0.12 per share.

- The unrealized value of the commodity price contracts was $12.9 million at year end and, during the fourth quarter, a cash gain of $0.5 million was realized.

- Debt plus working capital deficiency was $63.1 million at year end which is 1.1 times annualized fourth quarter cash flow. In November 2014, Storm's bank credit line was increased to $130.0 million from $90.0 million.

2014 YEAR-END RESERVE EVALUATION HIGHLIGHTS

	Dec 31, 2014	Dec 31, 2013	Change
Reserves			
Proved Producing (Mboe)	13,487	7,579	+78%
Total Proved (Mboe)	59,551	20,764	+187%
Total proved plus Probable (Mboe)	88,024	40,541	+117%
Reserves per share			
Proved Producing (Mboe per million shares)	121	87	+39%
Total Proved (Mboe per million shares)	535	237	+125%
Total proved plus Probable (Mboe per million shares)	791	463	+71%
Finding and Development ("F&D") Cost including the change in future development capital and excluding revisions, acquisitions, dispositions			
Proved Producing ($/Boe)	$13.73	$19.53	-30%
Total Proved ($/Boe)	$10.20	$13.98	-27%
Total proved plus Probable ($/Boe)	$8.76	$10.75	-18%
All-in Finding, Development, and Acquisition ("FD&A") Cost including the change in future development capital			
Proved Producing ($/Boe)	$23.01	$17.22	+34%
Total Proved ($/Boe)	$11.68	$13.19	-11%
Total proved plus Probable ($/Boe)	$9.64	$9.79	-1%
Recycle Ratio using F&D			
Annual field operating netback excluding hedging	$21.19	$20.43	
Proved Producing	1.5 X	1.0 X	
Total Proved recycle	2.1 X	1.5 X	
Total Proved plus Probable recycle	2.4 X	1.9 X	
Recycle Ratio using all-in FD&A			
Annual field operating netback excluding hedging	$21.19	$20.43	
Proved Producing	0.9 X	1.2 X	
Total Proved recycle	1.8 X	1.6 X	
Total Proved plus Probable recycle	2.2 X	2.1 X	
Reserve Life Index using fourth quarter production			
Total Proved	16.1 years	11.9 years	
Total Proved plus Probable	23.7 years	23.3 years	
Net Present Value Discounted at 10% (before tax)			
Proved Producing ($M)	$199,000	$122,000	+63%
Total Proved ($M)	$493,000	$184,000	+168%
Total proved plus Probable ($M)	$684,000	$298,000	+130%

- Reserve additions replaced 332% of 2014 production on a proved producing basis, 1,522% on a total proved basis, and 1,863% on a total proved plus probable basis.
- The all-in 2P 2014 FD&A cost of $9.64 was impacted by an acquisition in the Umbach area in January 2014 for a total cost of $88.0 million with $78.2 million allocated to acquiring undeveloped land and the remainder to acquiring production and reserves. The 2P F&D cost of $8.76 per NI 51-101 guidelines more realistically reflects the cost of developing the Montney at Umbach in 2014 as this excludes the effect of acquisitions, dispositions and revisions.
- At Umbach, the area where total proved plus probable reserves were assigned grew to 18% of Storm's 141 net sections from 8% last year and this included 73.4 net horizontal drilling locations which represents approximately five years of activity.
- Storm's enterprise value at the end of 2014 was $523.9 million which is equal to $16.32 per Boe on a 1P basis including future development costs ("FDC") and $12.85 per Boe on a 2P basis including FDC (using 111.3 million shares outstanding, the December 31 closing share price of $4.14 and year-end debt of $63.1 million).
- Storm's asset value using shares outstanding at year end grew to $5.58 per share from $3.25 per share last year and this excludes any amount for undeveloped land. Asset value was determined by deducting net debt at year end from the before tax net present value for proved plus probable reserves discounted at 10%.

OPERATIONS REVIEW

Storm has a focused asset base with large land positions in resource plays at Umbach and in the Horn River Basin ("HRB") each of which have multi-year drilling upside while the Grande Prairie area, with its shallow decline, provides cash flow available for investment.

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 141 net sections (167 gross sections), or 100,000 net acres. To date, a total of 30.4 net horizontal wells (34.0 gross) have been drilled into the Montney formation with 20.4 net being on production.

Fourth quarter production from Umbach was 8,775 Boe per day with NGL production of 1,540 barrels per day representing a recovery of 35 barrels per Mmcf sales (approximately 60% higher priced condensate plus pentanes). Revenue from Umbach was $29.08 per Boe ($3.88 per Mcf sales and $56.33 per barrel of NGL), transportation costs were $1.81 per Boe, royalties were $3.86 per Boe, or 13% of revenue, operating costs were $7.90 per Boe and the operating netback was $15.51 per Boe.

Activity in the fourth quarter included drilling two Montney horizontal wells (2.0 net) and completing four Montney horizontal wells (4.0 net) with three horizontal wells (3.0 net) starting production. In 2014, 16 Montney horizontal wells (16.0 net) were drilled and 13 horizontal wells (12.6 net) were completed which includes two wells (1.6 net) drilled in 2012 and 2013. Ten (9.6 net) of the completed horizontal wells started producing in 2014. There remains an inventory of 11 horizontal wells (11.0 net) that have not started producing which includes four completed horizontal wells and seven standing horizontal wells awaiting completion. In addition, two horizontal wells (2.0 net) remain to be drilled during the first quarter of 2015.

Storm operates two field compression facilities (both 100% working interest) that have total capacity of 45 Mmcf per day raw gas with the gas from both directed to the McMahon Gas Plant for processing. The first field compression facility with capacity of 18 Mmcf per day raw gas had average throughput of 17 Mmcf per day raw gas in the fourth quarter, with NGL recovery of 30 barrels per Mmcf sales. The second field compression facility with 27 Mmcf per day of capacity was started up in August 2014 and throughput in the fourth quarter averaged 24 Mmcf per day of gross raw gas with NGL recovery of 34 barrels per Mmcf of sales. Final cost of the second facility was $15.3 million (9% higher than initial guidance). Capacity of the second facility is being increased to 55 Mmcf per day raw gas in late March 2015 with the estimated cost being $13.5 million ($3.9 million to purchase equipment in 2014 and the remaining $9.6 million in the first quarter of 2015). In the second quarter of 2015, a condensate stabilizer and other equipment will be installed at the second facility with the estimated cost being $5.1 million.

During the first quarter of 2015, a 15-kilometre pipeline will be constructed to connect the first field compression facility to the Stoddart Gas Plant. The estimated gross cost is $4.8 million with Storm's working interest being 60%. This will increase NGL recovery from 30 to 55 barrels per Mmcf for production from the first field compression facility which has capacity of 18 Mmcf per day raw gas.

Construction of a third field compression facility (announced on November 13, 2014) is being deferred given the recent decline in NGL and natural gas prices. Engineering design has been completed and $5.0 million will be invested to purchase major equipment in 2015, which will shorten the construction period to six months once a decision is made to go ahead (likely in 2016). Total cost of the third facility is estimated to be $24.0 million for 35 Mmcf per day raw gas capacity and it will be expandable to 70 Mmcf per day for an additional investment of $7.0 million.

Comparing calendar day rates (includes downtime) over the first 180 days, the five 2014 Montney horizontal wells with enough history are 72% better than the average 2013 horizontal well. Following is a comparison of calendar day rates for all of the producing Montney horizontal wells.

	Frac Stages	**IP 90 Cal Day Gross Raw Mmcf Per Day**	**IP 180 Cal Day Gross Raw Mmcf Per Day**	**IP 365 Cal Day Gross Raw Mmcf Per Day**
2011 hz's (4 wells)	7 - 11	**2.0 Mmcf/d** 360 Boe/d sales 4 hz's	**1.5 Mmcf/d** 270 Boe/d sales 4 hz's	**1.3 Mmcf/d** 235 Boe/d sales 4 hz's
2012 hz's (3 wells)	14	**1.6 Mmcf/d** 290 Boe/d sales 3 hz's	**1.3 Mmcf/d** 235 Boe/d sales 3 hz's	**1.5 Mmcf/d** 270 Boe/d sales 3 hz's
2013 hz's (6 wells)	16 - 18	**3.5 Mmcf/d** 630 Boe/d sales 6 hz's	**2.9 Mmcf/d** 525 Boe/d sales 6 hz's	**2.2 Mmcf/d** 400 Boe/d sales 6 hz's
2014 hz's (7 wells)	16 - 20	**4.8 Mmcf/d** 865 Boe/d sales 10 hz's	**5.0 Mmcf/d** 900 Boe/d sales 5 hz's	**4.3 Mmcf/d** 780 Boe/d sales 1 hz
Sales volume is calculated using 8% shrinkage from raw gas to sales and 30 barrels of NGL per Mmcf sales.				

Based on the performance of the 2014 horizontal wells and given that the majority of horizontal wells that will be completed in 2015 are 20% longer with more frac stages (20 to 24), Storm management is now using a 6.3 Bcf raw gas type curve for internal budgeting purposes (this type curve has same decline profile as the 3.2 and 4.4 Bcf raw gas 2P type curves used by InSite in the 2014 reserve evaluation). Previously, a 5.0 Bcf raw type curve was used which was based on the performance of the 2013 and 2014 horizontal wells. With a 6.3 Bcf raw gas type curve, the first year average rate is 3.6 Mmcf per day gross raw gas or 650 Boe per day sales (8% shrinkage from raw gas to sales and 30 barrels of NGL per Mmcf sales). Based on a cost of $5.4 million to drill, complete and tie in a horizontal well with 20 to 24 frac stages, the payout is approximately 23 months and the rate of return is 35% assuming flat pricing of $3.00 per GJ at AECO and Cdn $66.00 per barrel for Edmonton light oil (see presentation on website for further details). In 2014, the cost to drill a horizontal well averaged $2.1 million with the completion cost averaging $2.5 million for 16 to 20 frac stages. Drilling times have averaged approximately 14 days. Tie-in costs have averaged $0.3 million per horizontal well which doesn't include the cost of longer gathering pipelines to connect multi-well pads to field compression facilities. With the 2015 horizontal wells having an increased number of frac stages (20 to 24), the cost to drill, complete, and tie in a horizontal well was also increased to $5.4 million. These results do not recognize any improvement in service costs in 2015.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 123 sections in the HRB (81,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Fourth quarter production averaged 307 Boe per day (100% natural gas), a year-over-year decline of 15%. The operating netback was $5.91 per Boe with revenue of $18.41 per Boe, transportation costs of $0.66 per Boe, an operating cost of $9.95 per Boe and a royalty of $1.89 per Boe, or 10% of revenue.

Grande Prairie Area, Northwest Alberta and Northeast British Columbia

Production in the fourth quarter was 1,091 Boe per day (41% oil plus NGL), a year-over-year decline of 5%. The operating netback was $19.96 per Boe with revenue of $41.35 per Boe, a transportation cost of $3.14 per Boe, an operating cost of $12.04 per Boe and a royalty of $6.20 per Boe, or 15% of revenue. Cash flow from this area continues to be re-invested to grow production at Umbach.

In mid-January 2015, approximately 150 Boe per day was shut in as a result of the recent decline in the natural gas price.

HEDGING UPDATE

For 2015, commodity price hedges include both fixed price swaps and collars with:

- 22,500 Mcf per day (27,900 GJ per day) of natural gas from January to December at an average floor price of approximately $4.28 per Mcf and an average ceiling price of $4.54 per Mcf (AECO monthly index $3.45 per GJ for floor and $3.66 per GJ for ceiling);

- 533 barrels per day of oil from January to September at a price of WTI Cdn$98.43 per barrel. This hedge was sold in January 2015 for net proceeds of $5.1 million.

At the end of 2014, the unrealized gain on the 2015 commodity prices hedges was $12.9 million.

The purpose of Storm's commodity price hedges is to reduce the effect of commodity price fluctuations on capital investment and growth over the next 12 months. A maximum of 50% of current production (most recent monthly or quarterly average), before royalties, will be hedged; anticipated production growth is not hedged.

COMPARISON OF 2014 RESULTS VERSUS GUIDANCE

Shown below is a comparison of Storm's actual 2014 results to guidance provided during 2014.

2014 Guidance	January 23, 2014 Original Guidance	May 14, 2014 Revised Guidance	November 13, 2014 Revised Guidance	Actual 2014 Results
AECO natural gas price	$3.35 per GJ	$4.25 per GJ	$4.30 per GJ	$4.27 per GJ
Edmonton light oil price	Cdn $89 per Bbl	Cdn $94 per Bbl	Cdn $97 per Bbl	Cdn $95 per Bbl
Average operating costs	$8.00 - $9.00 per Boe	$8.00 - $9.00 per Boe	$9.00 - $9.50 per Boe	$9.33 per Boe
Average royalty rate (% of revenue before hedging)	14% - 15%	15% - 16%	15%	13.7%
Operations capital (excluding acquisitions & dispositions)	$78.0 million	$97.0 million	$105.0 million	$106.7 million
Land & property acquisitions	$88.0 million	$88.0 million	$88.0 million	$88.0 million
Cash G&A	$4.0 million	$4.0 million	$3.8 million	$3.8 million
Forecast fourth quarter production	7,500 – 7,900 Boe/d (20% oil + NGL)	8,900 – 9,200 Boe/d (20% oil + NGL)	10,500 Boe/d (20% oil + NGL)	10,173 Boe/d(1) (20% oil + NGL)
Forecast annual production	5,500 – 6,500 Boe/d (21% oil + NGL)	6,000 – 6,700 Boe/d (21% oil + NGL)	7,000 Boe/d (21% oil + NGL)	6,980 Boe/d (21% oil + NGL)
Umbach horizontal wells drilled	10 gross (10.0 net)	14 gross (14.0 net)	16 gross (16.0 net)	16 gross (16.0 net)
Umbach horizontal wells completed	9 gross (9.0 net)	13 gross (12.6 net)	13 gross (12.6 net)	13 gross (12.6 net)

(1) Forecast production for the fourth quarter was impacted by an unplanned outage at the McMahon Gas Plant which resulted in the loss of 2,500 Boe per day for seven days in November.

OUTLOOK

Production in January 2015 averaged 10,060 Boe per day based on field estimates and production in the first quarter of 2015 is forecast to be 9,500 to 10,000 Boe per day which includes three to five days of downtime at Umbach for piping connections associated with the expansion of the second field compression facility. Capital investment in the first quarter is expected to total $35.0 to $38.0 million which includes drilling six Montney horizontal wells (6.0 net), completing two horizontal wells (2.0 net), constructing a 15-kilometer pipeline connection to the Stoddart Gas Plant and expanding the second field compression facility at Umbach. At Umbach, the existing field compression facilities are full and there is currently an inventory of 11 horizontal wells (11.0 net) that will start production after the second field compression facility is expanded from 27 to 55 Mmcf per day raw gas in late March.

Guidance for 2015 is being revised from original guidance provided November 13, 2014. Due to the recent decline in oil and natural gas prices, operations capital expenditures will be reduced to $80.0 million from $110.0 million. The effect on production guidance is expected to be minimal because Umbach horizontal well performance has been higher than that used in the production forecast. In addition, throughput at the second Umbach field compression facility has been 27 Mmcf per day raw gas which has exceeded the design capacity of 24 Mmcf per day and the expansion in March is now expected to increase capacity to 55 Mmcf per day raw gas versus previous expectations of 48 Mmcf per day.

2015 Guidance	November 13, 2014 Original Guidance	February 26, 2015 Revised Guidance
AECO natural gas price	$3.25 per GJ	$2.35 - $2.90 per GJ
BC STN 2 natural gas price	$3.00 per GJ	$2.05 - $2.60 per GJ
Edmonton light oil price	Cdn$83 per Bbl	Cdn$53 - $62 per Bbl
Estimated average operating costs	$7.50 - $8.00 per Boe	$8.00 - $8.50 per Boe
Estimated average royalty rate (on production revenue before hedging)	12% - 14%	6% - 10%
Estimated operations capital (excluding acquisitions & dispositions)	$110.0 million	$80.0 million
Estimated land & property acquisitions	$0.0 million	$0.0 million
Estimated cash G&A net of recoveries	$5.3 million	$5.3 million
Forecast fourth quarter production	14,000 – 14,500 Boe/d (18% oil + NGL)	14,000 – 14,500 Boe/d (19% oil + NGL)
Forecast annual production	11,500 – 12,700 Boe/d (19% oil + NGL)	11,000 – 12,000 Boe/d (20% oil + NGL)
Umbach horizontal wells drilled	9 gross (9.0 net)	6 gross (6.0 net)
Umbach horizontal wells completed	14 gross (14.0 net)	11 gross (11.0 net)
Umbach horizontal wells starting production	16 gross (16.0 net)	14 gross (14.0 net)

Capital investment for 2015 includes:

- $47.8 million at Umbach for drilling and completions;
- $18.4 million to expand infrastructure at Umbach, including expansion of the second field compression facility from 27 Mmcf per day to 55 Mmcf per day in late March; and
- $5.0 million to order major equipment for a third field compression facility at Umbach which will shorten the construction period to six months once a decision is made to build it.

This level of investment is forecast to increase production in the fourth quarter of 2015 to 14,000 to 14,500 Boe per day which represents 40% growth per share on a year-over-year basis.

Average production in 2015 is forecast to be 11,000 to 12,000 Boe per day with the mid-point representing an increase of 67% from average production in 2014. This includes approximately 60% of Umbach production being shut in for 35 days from June 6 to July 11 for a scheduled maintenance turnaround at the McMahon Gas Plant.

Total debt at the end of 2015 is forecast to be $85.0 to $96.0 million which would be approximately 1.2 to 1.9 times annualized funds from operations in the fourth quarter of 2015 (assuming commodity prices in 2015 average AECO $2.35 to 2.90 per GJ and Edmonton light oil Cdn$53.00 to $62.00 per barrel). The year-over-year increase in debt is forecast to be 30% to 50% which is consistent with year-over-year production growth. Debt is primarily funding infrastructure expansion at Umbach in 2015 which is an investment in a long-life asset.

Storm is still in the early stages of delineating a large, higher quality, liquids-rich resource in the Montney formation at Umbach. At the end of 2014, proved plus probable reserves were assigned on only 18% of Storm's land position (25.5 net sections of 141 net sections) leaving room for significant future reserve growth from drilling horizontal wells to test the remaining lands which appear to be highly prospective given horizontal well results on offsetting acreage. In addition, continuing to optimize horizontal well length, spacing between horizontal wells, number of frac stages and completion techniques is also likely to increase reserve bookings per horizontal well and will reduce the cost of reserve additions.

Although the recent decline in commodity prices is going to make 2015 much more challenging, Storm's commodity price hedges will mitigate the impact. In addition, the liquids-rich natural gas in the Montney at Umbach provides

Storm with a competitive advantage from increased revenue through NGL recovery while the relatively shallow depth (1,400 to 1,600 metres) results in a lower drilling and completion cost. With an evolving long term plan in place to continue expanding infrastructure, plus a large inventory of horizontal drilling locations that provide reasonable rates of return at relatively low commodity prices, high levels of growth are expected to continue for the next three to five years.

Storm's land position in the HRB 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 and Storm's Directors for their valuable advice and guidance in 2014 which resulted in record levels of production plus significant growth in reserves and asset value.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 26, 2015

Discovered-Petroleum-Initially-in-Place ("DPIIP") - is defined in the Canadian Oil and Gas Evaluation Handbook ("COGEH") as the quantity of hydrocarbons that are estimated to be in place within a known accumulation. DPIIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources. There is no certainty that it will be economically viable or technically feasible to produce any portion of this DPIIP except for those portions identified as proved or probable reserves.

Contingent Resources - are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project at an early stage of development. Estimates of contingent resources are estimates only; the actual resources may be higher or lower than those calculated in the independent evaluation. There is no certainty that the resources described in the evaluation will be commercially produced.

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 26, 2015 for the three months and year ended December 31, 2014.

RESERVES AT DECEMBER 31, 2014

Storm's year-end reserve evaluation effective December 31, 2014 was prepared by InSite Petroleum Consultants Ltd. ("InSite") under date of February 18, 2015. InSite has evaluated all of Storm's crude oil, NGL and natural gas reserves. The InSite price forecast at December 31, 2014 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 78% to total 13,487 Mboe with additions replacing 332% of 2014 production.
- Total proved ("1P") reserves increased 187% to total 59,551 Mboe with additions replacing 1,522% of 2014 production.
- Total proved plus probable ("2P") reserves increased 117% to total 88,024 Mboe with additions replacing 1,863% of 2014 production.
- Total proved reserves were 68% of total proved plus probable reserves, a significant improvement from 51% in 2013.
- The finding and development ("F&D") cost for reserve additions per NI 51-101 requirements (removing effect of acquisitions, dispositions and revisions) was $13.73 per Boe for PDP, $10.20 per Boe for 1P and $8.76 per Boe for 2P.
- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $23.01 per Boe for PDP, $11.68 per Boe for 1P and was $9.64 per Boe for 2P.
- Reserve life index using average production in the fourth quarter of 2014 was 3.6 years for PDP reserves, 16.1 years for 1P reserves and 23.3 years for 2P reserves.
- Recycle ratio using the F&D cost was 2.1 for 1P reserve additions and 2.4 for 2P reserve additions using the 2014 field operating netback of $21.19 per Boe excluding hedging gains or losses.
- Recycle ratio using the FD&A cost was 1.8 for 1P reserve additions and 2.2 for 2P reserve additions using the 2014 field operating netback of $21.19 per Boe excluding hedging gains or losses.
- Technical revisions increased PDP reserves by 130 Mboe, 1P reserves by 2,068 Mboe and 2P reserves by 4,352 Mboe.
- Breaking down 2P reserves by area, 86% is at Umbach, 9% at the Horn River Basin ("HRB") and 5% is at Grande Prairie.
- Future development costs ("FDC") were $447.7 million on a 1P basis and $606.6 million on a 2P basis which represents approximately five years of activity in the evaluation.

- At Umbach, there are 30.4 net producing and non-producing horizontal wells with 21,749 Mboe of 2P reserves plus 73.4 net future horizontal drilling locations with 53,519 Mboe of 2P reserves. Associated 2P FDC was $484.0 million net.

- At Umbach, 53 net 2P horizontal drilling locations were assigned an average of 4.4 Bcf gross raw gas on the 100% working interest lands, an increase of 26% from 3.5 Bcf gross raw gas assigned in 2013. On the 60% working interest lands, 20.4 net 2P horizontal drilling locations were assigned an average of 3.2 Bcf gross raw gas, an increase of 7% from 3.0 Bcf gross raw gas assigned in 2013.

- At Umbach, 2P reserves were recognized in the upper Montney only on 18% or 25.5 net sections of Storm's 141 net sections in the area with DPIIP averaging 43 Bcf gross raw gas per section in the upper Montney (total net DPIIP 1.1 Tcf on 25.5 net sections). Forecast recovery of DPIIP totals 40% for 2P reserves.

- The forecast decline in 2015 is 35% for wells on production at December 31, 2014 (decline from January 2015 to December 2015).

(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, 2014, 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, 2014
(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	940	62,696	2,098	13,487
Proved non-producing	-	10,676	373	2,153
Total proved developed	940	73,372	2,471	15,640
Proved undeveloped	300	222,301	6,560	43,911
Total proved	1,240	295,673	9,032	59,551
Probable additional	846	144,778	3,498	28,473
Total proved plus probable	2,086	440,452	12,530	88,024

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2014
(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, 2013 - opening balance	7,579	20,764	19,777	40,541
Acquisitions	558	558	119	677
Discoveries	-	-	-	-
Extensions	7,766	38,707	6,295	45,002
Dispositions	-	-	-	-
Technical revisions – Umbach	292	2,284	2,514	4,798
Technical revisions – other properties	(162)	(216)	(230)	(446)
Economic factors	-	-	-	-
Production	(2,547)	(2,547)	-	(2,547)
December 31, 2014 – closing balance	13,487	59,551	28,473	88,024

Numbers in this table may not add due to rounding.

Future Development Costs ("FDC")

Proved		
HRB	Drill 2.0 net horizontals plus infrastructure	$ 35.5 million
Umbach	Drill 59.0 net horizontals plus infrastructure	$ 404.5 million
Grande Prairie	Drill 3.0 net horizontals at Grimshaw	$ 7.7 million
Total		$ 447.7 million

Proved Plus Probable Additional		
HRB	Drill 5.0 net horizontals plus infrastructure	$ 85.5 million
Umbach	Drill 73.4 net horizontals plus infrastructure	$ 483.7 million
Grande Prairie	Drill 5.0 net horizontals at Grimshaw; 5.0 net horizontals at GP Montney; and 1.0 net horizontal at GP Dunvegan	$ 37.4 million
Total		$ 606.6 million

	Proved Expenditures	Proved Plus Probable Additional Expenditures
2015	57,250	63,250
2016	75,154	89,678
2017	122,819	152,793
2018	129,637	153,461
2019	62,857	141,907
2020	-	5,465
Total FDC - undiscounted	447,717	606,555
Total FDC - discounted at 10%	356,196	470,717

Note: InSite escalates capital costs at 2% per year after 2015.
Numbers in this table may not add due to rounding.

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

Proved Developed Producing F&D Cost	2014	2013	2012	3 Year Total
Capital expenditures excluding acquisitions				
and dispositions (000s)	$ 106,604	$ 67,450	$ 26,868	$ 200,922
Net change in FDC (000s)	-	-	-	-
Total capital	$ 106,604	$ 67,450	$ 26,868	$ 200,922
Reserve additions excluding acquisitions, dispositions,				
and revisions (Mboe)	7,766	3,464	840	12,070
Proved developed producing F&D cost	$ 13.73	$ 19.47	$ 31.99	$ 16.64

Total Proved F&D Cost	2014	2013	2012	3 Year Total
Capital expenditures excluding acquisitions				
and dispositions (000s)	$ 106,604	$ 67,450	$ 26,868	$ 200,922
Net change in FDC (000s)	288,242	77,282	30,863	396,387
Total capital including the net change in future capital (000s)	$ 394,846	$ 144,732	$ 57,731	$ 597,309
Reserve additions excluding acquisitions, dispositions,				
and revisions (Mboe)	38,707	10,356	4,067	53,130
Total proved F&D cost (per Boe)	$ 10.20	$ 13.98	$ 14.20	$ 11.24

Total Proved Plus Probable F&D Cost	2014	2013	2012	3 Year Total
Capital expenditures excluding acquisitions				
and dispositions (000s)	$ 106,604	$ 67,450	$ 26,868	$ 200,922
Net change in FDC (000s)	287,686	134,903	40,341	462,930
Total capital including the net change in future capital (000s)	$ 394,290	$ 202,353	$ 67,209	$ 663,852
Reserve additions excluding acquisitions, dispositions,				
and revisions (Mboe)	45,001	18,823	5,514	69,338
Total proved plus probable F&D cost	$ 8.76	$ 10.75	$ 12.19	$ 9.57
Operating netback per Boe excluding hedging	$ 21.19	$ 20.43	$ 21.22	$ 20.97
Recycle ratio for proved plus probable F&D cost				
using operating netback (excluding hedging)	2.4	1.9	1.7	2.2

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

Proved Developed Producing FD&A Cost	2014	2013	2012	3 Year Total
Capital expenditures including acquisitions and dispositions (000s)	$ 194,555	$ 52,444	$ 166,076	$ 413,075
Net change in FDC (000s)	-	-	-	-
Total capital	$ 194,555	$ 52,444	$ 166,076	$ 413,075
Total reserve additions (Mboe)	8,456	3,047	5,117	16,620
All-in proved developed producing FD&A cost	$ 23.01	$ 17.21	$ 32.46	$ 24.85

Total Proved FD&A Cost	2014	2013	2012	3 Year Total
Capital expenditures including acquisitions and dispositions (000s)	$ 194,555	$ 52,444	$ 166,076	$ 413,075
Net change in FDC (000s)	288,242	56,600	72,655	417,497
Total capital including the net change in future capital (000s)	$ 482,797	$ 109,044	$ 238,731	$ 830,572
Total reserve additions (Mboe)	41,334	8,270	10,927	60,531
All-in total proved FD&A cost (per Boe)	$ 11.68	$ 13.19	$ 21.85	$ 13.72

Total Proved Plus Probable FD&A Cost	2014	2013	2012	3 Year Total
Capital expenditures including acquisitions and dispositions (000s)	$ 194,555	$ 52,444	$ 166,076	$ 413,075
Net change in FDC (000s)	287,686	89,829	156,258	533,773
Total capital including the net change in future capital (000s)	$ 482,241	$ 142,273	$ 322,334	$ 946,848
Total reserve additions (Mboe)	50,030	14,538	19,828	84,396
All-In total proved plus probable FD&A cost (per Boe)	$ 9.64	$ 9.79	$ 16.26	$ 11.22
Operating netback per Boe excluding hedging	$ 21.19	$ 20.43	$ 21.22	$ 20.97
Recycle ratio for proved plus probable FD&A cost using operating netback (excluding hedging)	2.2	2.1	1.3	1.9

Net Present Value Summary (before tax) as at December 31, 2014

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	$ 301,021	$ 239,533	$ 199,069	$ 170,841	$ 150,201
Proved non-producing	48,474	38,290	31,796	27,351	24,134
Total proved developed	$ 349,495	$ 277,823	$ 230,865	$ 198,192	$ 174,335
Proved undeveloped	694,842	421,652	262,392	163,942	100,157
Total proved	$ 1,044,338	$ 699,476	$ 493,257	$ 362,133	$ 274,492
Probable additional	629,545	332,499	190,573	115,724	73,005
Total proved plus probable	$ 1,673,883	$ 1,031,974	$ 683,829	$ 477,858	$ 347,497

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2014

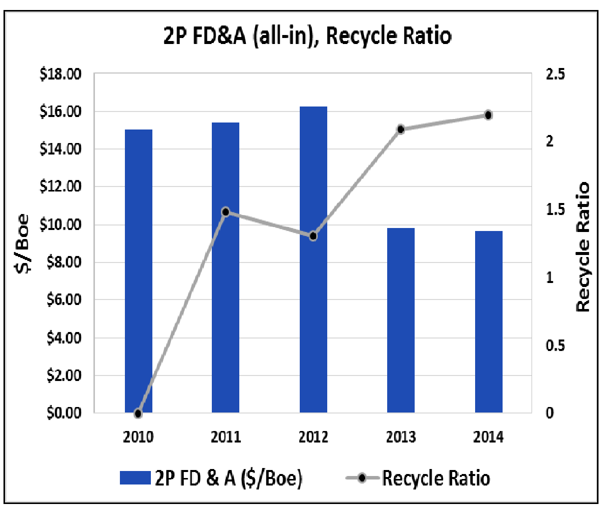
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPVs each include a deduction for estimated future well abandonment costs.

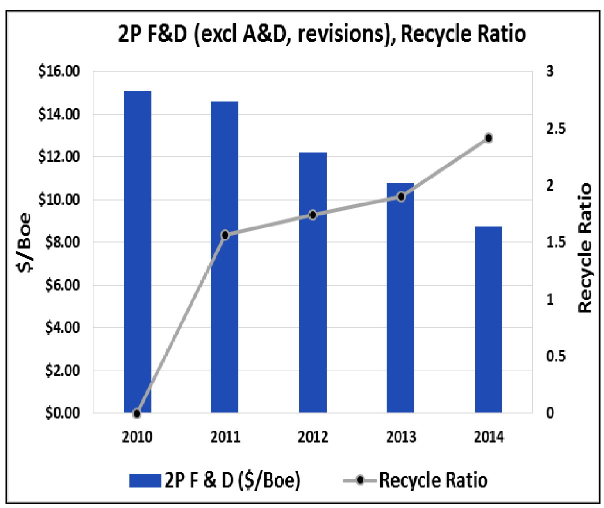
	Undiscounted (000s)	Discounted at 5% (000s)	Discounted at 10% (000s)	Discounted at 15% (000s)	Discounted at 20% (000s)
Proved producing	$ 301,021	$ 239,533	$ 199,069	$ 170,841	$ 150,201
Proved non-producing	48,474	38,290	31,796	27,351	24,134
Total proved developed	$ 349,495	$ 277,823	$ 230,865	$ 198,192	$ 174,335
Proved undeveloped	531,153	318,100	193,246	115,727	65,343
Total proved	$ 880,649	$ 595,923	$ 424,111	$ 313,919	$ 239,677
Probable additional	473,166	246,451	138,292	81,451	49,208
Total proved plus probable	$ 1,353,814	$ 842,374	$ 562,403	$ 395,370	$ 288,885

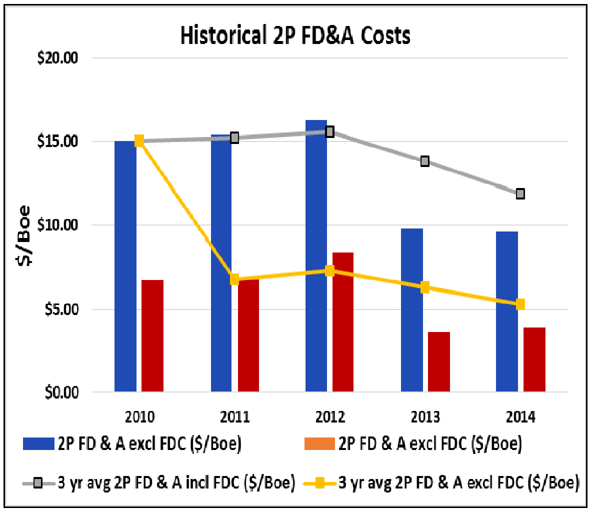
Numbers in this table may not add due to rounding.

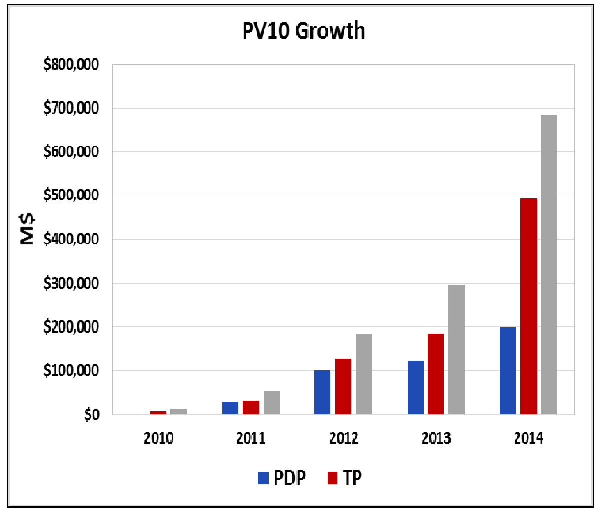
InSite Escalating Price Forecast as at December 31, 2014

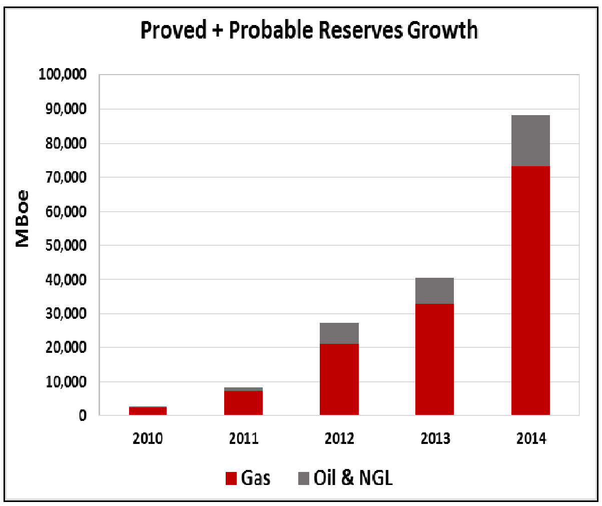
	WTI Crude Oil (US$/Bbl)	Edmonton Par Crude Oil (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	Propane (Cdn$/Bbl)	Butane (Cdn$/Bbl)
2015	65.00	68.58	3.50	3.58	34.29	48.01
2016	75.00	80.07	4.00	4.15	40.03	56.05
2017	80.00	85.74	4.25	4.43	42.87	60.02
2018	85.00	91.41	4.50	4.71	45.70	63.99
2019	90.00	97.07	4.75	4.99	48.54	67.95

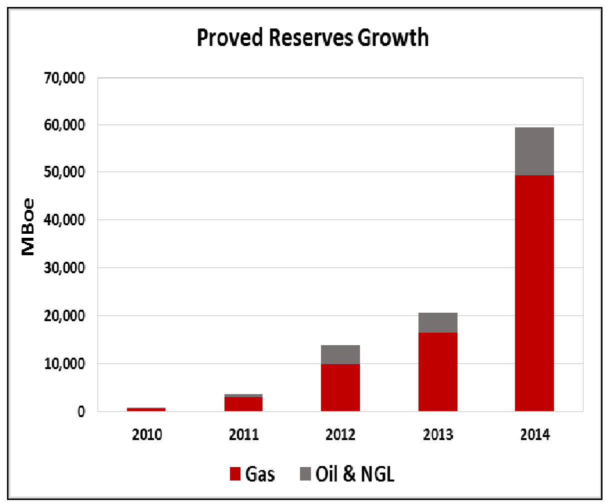


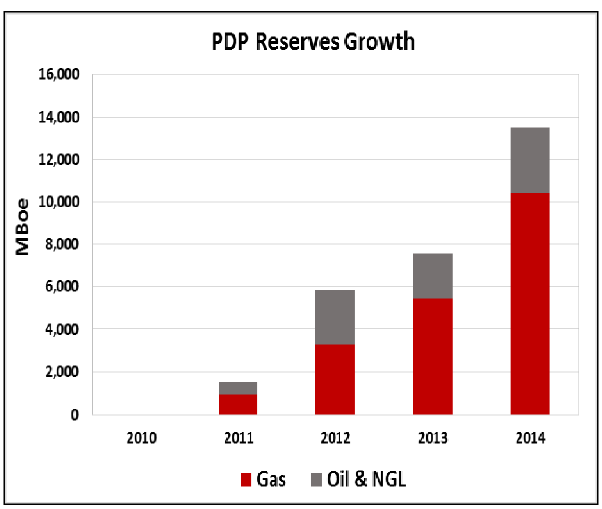


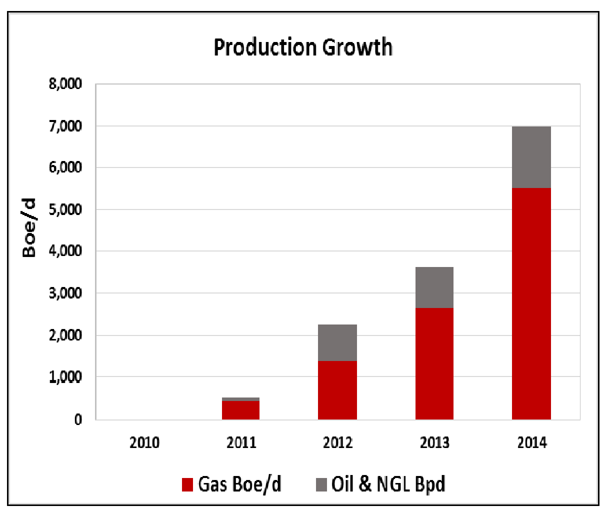

Historical 2P FD&A Costs
$/Boe
$20.00
$15.00
$10.00
$5.00
$0.00
2010
2011
2012
2013
2014
2P FD & A excl FDC ($/Boe)
2P FD & A excl FDC ($/Boe)
3 yr avg 2P FD & A incl FDC ($/Boe)
3 yr avg 2P FD & A excl FDC ($/Boe)


PV10 Growth
M$
$800,000
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
2010
2011
2012
2013
2014
PDP
TP


Proved + Probable Reserves Growth
MBoe
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
2010
2011
2012
2013
2014
Gas
Oil & NGL


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


PDP Reserves Growth
MBoe
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2010
2011
2012
2013
2014
Gas
Oil & NGL


Production Growth
Boe/d
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2010
2011
2012
2013
2014
Gas Boe/d
Oil & NGL Bpd

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, 2014. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2014 and 2013, (ii) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2014, and (iii) the press release issued by the Company on February 26, 2015, 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).

Readers are directed to the discussion below regarding Forward-Looking Statements, Boe Presentation and Non-GAAP Measurements.

The Company was incorporated on June 8, 2010 as 1541229 Alberta Ltd. with nominal share capital and was inactive until August 17, 2010 when the Company participated in a plan of arrangement (the "Arrangement") along with Storm Exploration Inc. ("SEO") and ARC Energy Trust ("ARC"). The Arrangement resulted in the sale of SEO to ARC and the spin out of the Company as a junior exploration and development company. The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated February 26, 2015. Review of operations for the year ended December 31, 2014 begins on page 20. Review of the fourth quarter of 2014 begins on page 34.

LIMITATIONS

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, 2014 and the unaudited condensed interim consolidated financial statements for the three months ended December 31, 2014, 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 year ended December 31, 2014 and 2013. The reporting and the measurement currency is the Canadian dollar.

Changes to accounting policies, introduced effective January 1, 2014, are outlined in Note 2 to the Company's audited consolidated financial statements as at December 31, 2014 and for the year then ended. These changes to accounting policies have no effect on the interim and annual financial statements in the year ended December 31, 2014 or the inter-period comparability of financial statements and financial information derived therefrom.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the year ended December 31, 2013.

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 wells, facilities, regions or projects. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices;
- future production levels and production levels by commodity;
- 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;
- future decommissioning costs and discount rates used to determine the net present value of such costs;
- development plans;
- estimates regarding the carrying amount of exploration and evaluation costs;
- estimates regarding the carrying amount of property and equipment;
- future debt levels;
- availability of credit facilities;
- 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;
- future royalties, operating costs, interest and general and administrative costs;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- future provisions for depletion and depreciation and accretion;
- expected 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 geographical areas developed; and
- changes to any of the foregoing.

Statements relating to “reserves” or “resources” 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"; "Risk Assessment" and the material assumptions described under the headings "Overview"; "Production and Revenue"; "Hedging"; "Royalties"; "Production Costs"; "Field Netbacks"; "General and Administrative Costs"; "Share-Based Compensation"; "Depletion and Depreciation"; "Accretion"; "Interest and Finance Costs"; "Reduction of Carrying Amount of Property and Equipment"; "Gain (Loss) on Commodity Price Contracts"; "Income Taxes"; "Other Comprehensive Income"; "Financial Resources and Liquidity"; "Investments"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Shareholders' Equity"; "Contractual Obligations"; industry conditions including commodity prices, capacity constraints and access to market for production, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and related costs including royalties, production 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 acquired assets and corporations. 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, the attitude of lenders and investors towards corporations in the energy industry, 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", "netbacks", "field operating income", "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 similar 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. These measurements are 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".

A review of Storm's operating results for 2014 follows: a review of the fourth quarter of 2014 begins on page 34.

OPERATIONAL AND FINANCIAL RESULTS

Overview

2014 was a year of continued strong growth for Storm. Production for the year increased by 92% compared to 2013 as the Company expanded its liquids-rich natural gas play at Umbach in northeast British Columbia. The Company drilled 16 horizontal wells (16.0 net) and one vertical well and tied in 10 horizontal wells (9.6 net) at Umbach. At December 31, 2014 Storm had drilled a total of 31 horizontal wells at Umbach, comprising 23 producing wells, three standing completed wells and five wells awaiting completion. In early 2014, Storm added to its land position at Umbach by acquiring two horizontal wells, then producing 359 Boe net per day, and 29 sections of undeveloped land contiguous to the Company's 100% working interest lands at Umbach South. The total cost of the acquisition was approximately $88.0 million, which consisted of $30.0 million in cash plus 13.6 million common shares at a deemed value of $4.25 per share. In mid-August a new field compression facility was commissioned at Umbach South. The new compressor station has been operating at 27 Mmcf per day capacity since late August. No wells were drilled in 2014 on any properties owned by the Company other than Umbach.

Umbach is a high NGL content natural gas property producing from the Montney formation. Although Storm is at an early stage in development of the play, results indicate that it is areally large and that drilling, completion and tie-in methodologies are highly repeatable, enabling the Company to manage downwards both capital and operating costs. At year end Storm had a total of 23 producing wells at Umbach with eight wells awaiting tie-in when facility capacity becomes available. Profitability of natural gas production at Umbach is supported by associated NGL, currently approximating 35 barrels per Mmcf, of which 60% is high value condensate and pentanes. The Company held a total of 141 net sections at the end of the year. A successful drilling program saw year-over-year reserve growth of 187% for proved reserves and 117% for proved plus probable reserves. Reserves have been recognized over approximately 18% of the Company's year-end land position.

In the Horn River Basin ("HRB"), the Company's one producing horizontal well continues to meet expectations and production is consistent with type curves in the region. At December 31, 2014 Storm had a net interest in 78,000 acres in the area. The scale of the resource in the HRB is potentially immense. However, development in the area continues to be challenged by prevailing natural gas prices and the Company has no plans for additional activity in the area until there is evidence of a substantial and sustainable increase in natural gas prices. The Company faces no immediate land expiries and can afford to be patient regarding future exploitation programs.

Production from the Company's Alberta properties, which were received as part of the Bellamont Exploration Ltd. acquisition in early 2012, is approximately 35% crude oil and has a stable decline rate, providing reasonably sustainable cash flow. Although the Alberta properties have development potential, it is limited in scale, certainly when compared to Umbach, and no capital programs are planned for the area in 2015.

Average daily production in 2014 increased 92% to 6,980 Boe per day from 3,637 Boe per day in 2013 with fourth quarter production rising by 113% from 4,773 Boe per day in 2013 to 10,173 Boe per day. These increases were a result of the increase in natural gas and associated NGL production at Umbach. Fourth quarter production at Umbach increased by 169% year over year; in the HRB production declined by 15%; and Alberta production decreased by 5%.

During 2014, Storm's production mix was 79% natural gas, 15% NGL and 6% crude oil, compared to 73% natural gas, 14% NGL and 13% crude oil in the prior year. Natural gas production increased by 109% relative to 2013. During the year, crude oil production dropped by 16% relative to 2013 as declines were not replaced through reinvestment. Meanwhile, NGL production increased 108% to 1,064 barrels per day from 512 barrels per day in 2013, commensurate with increased natural gas production at Umbach. However, the financial benefit of increased production was countered by falling prices for all of the Company's products. A slow erosion in prices realized by the Company throughout the year accelerated rapidly in the fourth quarter, with the result that the average realized price per Boe fell by nearly one-third between the first and fourth quarters of the year, with the average realized price for natural gas, Storm's most important product, falling by a largely similar amount as illustrated below.

Commodity Price Declines in 2014

Average Quarterly Per-Unit Realized Price (Cdn$)	Natural Gas		Natural Gas Liquids		Crude Oil		Boe	
Q1	$5.63	100%	$84.49	100%	$93.08	100%	$45.62	100%
Q2	$5.20	92%	$80.57	95%	$99.27	107%	$43.66	96%
Q3	$4.48	80%	$73.09	87%	$90.31	97%	$37.80	83%
Q4	$3.85	68%	$56.15	66%	$68.01	73%	$29.99	66%

Commodity price declines continued into 2015, although most recent prices have showed some signs of stabilization.

The effect of falling prices on Storm's cash flow will be in some degree mitigated by the Company's hedging program. At December 31, 2014 the Company had unrealized hedging gains of $12.9 million. In January 2015 the Company exited its crude oil hedge positions, realizing a cash gain of $5.1 million.

During 2014, in addition to the $88.0 million first quarter land and production acquisition at Umbach, Storm spent $106.6 million on operations capital. Major spending included $68.1 million on drilling and completions, and $34.3 million on facilities, equipping and tie-ins in the Umbach area. Key to expansion of the Company's production base at Umbach was the commissioning of a second field compression facility during the third quarter. As a result, fourth quarter production of natural gas and NGL was, respectively, 45% and 39% higher than the third quarter of the year. However, the second facility was full by the end of the fiscal year, and continuing production growth is dependent on expanding the facility, scheduled to be operational in late March 2015.

Increased production at Umbach resulted in an increase in funds from operations to $45.4 million ($0.42 per share), up from $21.9 million ($0.30 per share) in 2013.

In February 2014 the Company closed an equity financing for net proceeds of approximately $33.0 million. Storm's bank line at the beginning of 2014 was $65.0 million. The bank line increased to $90.0 million in May and again to $130.0 million in November in recognition of production growth at Umbach.

The timing of the construction of a third field compression facility, with an initial capacity of 35 Mmcf per day, expandable to 70 Mmcf per day, originally scheduled for October 2015, is being deferred.

In the fourth quarter of 2014, after review of the year-end independent reserve engineering report, the Company reduced the carrying amounts of its Alberta properties which exceeded an estimate of the net present value from the related cash generating units ("CGUs"), as more fully described on page 28. The reduction in the net present value from the properties is primarily due to a decrease in forecasted commodity prices.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				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

				Year Ended December 31, 2013
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	9,110	429	-	1,947
Horn River Basin – NE BC	2,101	-	-	350
Grande Prairie – AB	4,632	83	485	1,340
Total	15,843	512	485	3,637

Total Boe production in 2014 increased by 92% when compared to 2013. The year-over-year increase in production for natural gas and NGL came from Umbach where the Company began production from 10 wells (9.6 net) during the year. Four 100% working interest wells began production in August and September after the start-up of a new compression facility, with one 60% working interest well at Umbach North beginning production in July. Crude oil production decreased from the prior year as a result of natural declines. Production to date in 2015 is currently averaging about 10,000 Boe per day based on field estimates.

Daily production per million shares outstanding at the end of 2014 averaged 63 Boe per day, compared to 42 Boe per day in 2013, an increase of 50%.

HRB produces dry natural gas, while Umbach produces natural gas and associated NGL. Production in Alberta for 2014 approximated 37% light oil, with an average API of 37 degrees, 57% natural gas and 6% NGL.

Average Daily Production

	Year Ended December 31, 2014	Year Ended December 31, 2013
Natural gas (Mcf/d)	33,067	15,843
Natural gas liquids (Bbls/d)	1,064	512
Crude oil (Bbls/d)	405	485
Total (Boe/d)	6,980	3,637

Year-over-year growth in natural gas and NGL production comes from Umbach. The reduction in crude oil production largely reflects natural declines.

Production Profile and Per-Unit Prices(1)

	Year Ended December 31, 2014		Year Ended December 31, 2013	
	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	79%	$ 4.58	73%	$ 3.63
Natural gas liquids - Bbl	15%	69.90	14%	70.29
Crude oil - Bbl	6%	88.10	13%	87.16
Per Boe	100%	$ 37.48	100%	$ 37.34

(1) Before realized hedging losses of $1.26 per Boe for the year ended December 31, 2014 (2013 – loss of $0.03).

The Company's natural gas is produced in both British Columbia and Alberta and generally is sold at a price based on the Station 2 price in British Columbia and the AECO index in Alberta. Approximately 34% of 2014 natural gas sales were priced at the AECO monthly index price, 5% at the AECO daily index price and 61% was sold at the Station 2 daily index price. Equivalent percentages for the year ended December 31, 2013 were 30% at the AECO monthly index price with the remaining 70% being sold at Station 2 daily index price.

A summary of reference prices for 2014 and 2013 is as follows:

	2014			2013		
	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)
Q1	4.51	4.94	99.83	2.92	2.86	88.65
Q2	4.43	4.20	105.61	3.40	3.26	92.94
Q3	4.00	3.54	97.16	2.67	2.52	105.17
Q4	3.80	2.93	75.69	2.99	3.22	86.26
Average for year	4.19	3.90	94.57	3.00	2.96	93.25

A portion of Storm's natural gas is sold at the AECO monthly index price to align with the Company's natural gas hedges which are based on the monthly index.

Storm's realized price for the year was $4.58 per Mcf, with the price higher than index prices as a result of sales gas at Umbach and Grande Prairie having a higher heat content. The Station 2 daily index price for the year averaged $3.90 per GJ, the AECO monthly index price was $4.19 per GJ and the AECO daily index price was $4.27 per GJ.

The realized price for NGL was largely the same year over year. The NGL stream contains a high proportion of condensate and pentanes which are generally priced with reference to crude oil prices. Correspondingly, realized prices in the fourth quarter of 2014 and into 2015 fell in response to lower crude oil prices. As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production should continue to increase, both in total and as a percentage of product mix.

For the year, WTI averaged US$93.00 per barrel and Edmonton light oil was Cdn$94.57 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$8.13 per barrel, compared to Cdn$7.78 per barrel in 2013. Due to quality and gravity differentials, Storm's average crude oil sales price for 2014, prior to the inclusion of hedging losses, was $6.47 per barrel lower than the Edmonton light oil reference price.

Revenue from Product Sales(1)

(000s)	Year Ended December 31, 2014	Year Ended December 31, 2013
Natural gas	$ 55,316	$ 21,019
Natural gas liquids	27,144	13,124
Crude oil	13,020	15,435
Total	$ 95,480	$ 49,578

(1) Excludes hedging gains and losses.

The year-over-year increase in total revenue of 93% was a result of natural gas driven Boe production growth of 92%, combined with a marginal increase in Boe pricing. When converting natural gas into Boe, a rate of six Mmcf of natural gas to one Boe is the conversion convention based on energy content. In 2014, a sales value conversion rate from Mmcf to Boe, using prices realized by the Company during the year, was 19 Mmcf of natural gas to one Boe. As long as the disparity between a conversion based on energy content and a conversion based on pricing continues, increased natural gas production as a percentage of total production will have the effect of reducing the average selling price per Boe.

The year-over-year increase in total revenue is due to production having more than doubled at Umbach supported by a 26% increase in the yearly average price for natural gas. However, this price improvement benefited the first three quarters of 2014 only: in the fourth quarter of 2014 prices for all commodities had fallen considerably with natural gas prices being almost identical to the fourth quarter of 2013 and NGL and crude oil prices being much lower.

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – 2013	$ 21,019	$ 13,124	$ 15,435	$ 49,578
Effect of increased (decreased) production	22,831	14,170	(2,549)	34,452
Effect of changes in average product prices	11,466	(150)	134	11,450
Revenue from product sales - 2014	$ 55,316	$ 27,144	$ 13,020	$ 95,480

Hedging

The Company had in place the following hedging arrangements at December 31, 2014:

	WTI Crude Oil		AECO Natural Gas	
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q1 – 2015	600 Bbls/day	$101.06	2,000 GJ/day	$3.62
Q2 – 2015	600 Bbls/day	$ 98.34	21,667 GJ/day	$3.33
Q3 – 2015	400 Bbls/day	$ 94.61	30,000 GJ/day	$3.33
Q4 – 2015			30,000 GJ/day	$3.47
Collars		Average Range (Cdn$/Bbl)		Average Range (Cdn$/GJ)
Q1 – 2015			28,000 GJ/day	$3.62 - $4.40

In the year to December 31, 2014, the Company realized losses from hedges in place during the year in the amount of $3.2 million compared to $36,000 in 2013. Details by commodity of realized gains and losses are provided on page 29. The fair market value of hedges in place at December 31, 2014 was $12.9 million.

In January 2015 the Company terminated all of the above crude oil contracts in exchange for $5.1 million. This amount will be recognized as a realized gain in commodity price contracts in the first quarter of 2015. In February 2015 the Company added an additional fixed contract for 4,000 GJ/day of natural gas at an AECO price of $2.85 per GJ for the period from April 1, 2015 to September 30, 2015.

For natural gas volumes that have been hedged at AECO monthly index pricing, an equal volume of natural gas is sold at the same index.

All crude oil contracts are based on a WTI price in US$ per barrel which is then converted to Cdn$ using the foreign exchange rate at the time of execution of the contract. Crude oil contracts do not reflect wellhead prices as quality adjustments, market differentials and transportation tariffs are not included. Natural gas price hedges are based on pricing at Storm's physical delivery point for natural gas sales and are directly related to wellhead prices.

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 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

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 13,151	$ 6,035
Percentage of revenue from product sales	13.7%	12.2%
Per Boe	$ 5.16	$ 4.55

Royalties paid in 2014 increased by 118% when compared to 2013. Increased production revenue was the primary driver of increased royalties; however, royalties also increased as a result of the expiry of the 5% new well royalty incentive on certain horizontal wells in the Grande Prairie area which benefited the first half of 2013, and from the expiry of a Deep Well Royalty Credit in the HRB during the first quarter of 2014. This was offset by the receipt of infrastructure royalty credits at Umbach and the HRB which reduced 2014 royalties by a total of $1.9 million. As a result of a higher natural gas price in 2014, royalties as a percentage of revenue increased from 12% to 14% year over year.

At Umbach, future production will further benefit from British Columbia's Infrastructure Royalty Credit Program. During 2012 and 2013, Storm received approval for $4.3 million of royalty credits ($3.4 million net) for three pipeline projects. In late 2013, $745,000 of this amount was applied in reduction of royalties and the Company received approximately $1.6 million in the second quarter of 2014. The remaining amount of $1.0 million is expected to be realized in 2015 as the related pipeline projects are completed and incremental revenue eligible for royalty reduction is generated. During 2014, approval was received for an additional net amount of $4.7 million of royalty credits for a facility and related gathering pipelines, with this amount likely being received in 2015 and 2016. The timing of receipt of future credits is dependent on commodity prices and cannot be forecasted; correspondingly, royalty rates reported in future quarters could vary considerably depending on when future credits are received.

In HRB, the Company benefited from British Columbia's Deep Well Royalty Credit program, applicable to horizontal wells with a vertical depth greater than 1,900 metres. Under this program, which is not subject to expiry, drilling credits earned are applied in reduction of future royalties levied on production. The Company has received the full entitlement of $1.1 million and HRB production, absent further drilling, no longer benefits from royalty credits under this program. In 2012 the Company received approval for an infrastructure royalty credit of $1.0 million at HRB and received $0.3 million in 2014. 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. Wells spud after April 1, 2014 will benefit from this change. As a result, Storm expects that future horizontal wells at Umbach 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.

In Alberta, production from new wells is subject to a 5% royalty rate for the first 12 months of production, subject to a maximum volume of 50,000 Bbls of crude oil or 500 million cubic feet of natural gas. Lack of drilling activity in Alberta has resulted in the expiry of this program's benefits to Storm.

Production of NGL is subject to an effective royalty rate of 20% in British Columbia and approximately 25% to 30% in Alberta.

Production Costs

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 23,781	$ 14,414
Percentage of revenue from product sales	25.0%	29.1%
Per Boe	$ 9.33	$ 10.86

Total production costs for the year increased by 65% when compared to 2013 and decreased by 14% on a per-Boe basis. This increase in production costs largely corresponds to increased production at Umbach.

For 2014, production costs per Mcf of natural gas averaged $1.72 and production costs per barrel of crude oil averaged $20.30 with total production costs averaging $9.33 per Boe. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for 2013 were $2.08 per Mcf of natural gas and $13.50 per barrel for crude oil, with total production costs averaging $10.86 per Boe. The 50% increase in production costs for crude oil related to workovers and repairs and maintenance in the Grande Prairie area. Generally, production costs have been trending downwards for several quarters. This should continue into the future as lower cost natural gas grows as a percentage of the Company's production base.

Transportation Costs

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 4,594	$ 1,993
Percentage of revenue from product sales	4.8%	4.0%
Per Boe	$ 1.80	$ 1.50

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 and for crude oil in Alberta. Total transportation costs for 2014 increased by 130% over 2013 consistent with increased production and the shift in commodity mix. Per Boe, transportation costs averaged $1.80 in 2014 compared to $1.50 in 2013. The increase was mainly due to high initial volumes of condensate from new wells at Umbach which resulted in higher trucking costs.

Year over year, there were increases in total transportation costs for all three commodities.

Field Netbacks

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

	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
				Year Ended December 31, 2014
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 income 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

	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
				Year Ended December 31, 2013
Production revenue	$ 3.63	$ 70.29	$ 87.16	$ 37.34
Royalties	(0.04)	(11.83)	(20.23)	(4.55)
Production costs	(2.08)	-	(13.50)	(10.86)
Transportation costs	(0.17)	(1.38)	(4.18)	(1.50)
Field operating income before hedging	$ 1.34	$ 57.08	$ 49.25	$ 20.43
Realized hedging gains (losses)	0.13	-	(4.33)	(0.03)
Total operating income per commodity unit	$ 1.47	$ 57.08	$ 44.92	$ 20.40
Total operating income (000s)	$ 8,489	$ 10,656	$ 7,955	$ 27,100

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

Total field operating income for 2014 was 87% higher than for 2013. Combined operating income from natural gas and NGL rose by 134% in 2014 as a result of increased production at Umbach, while operating income from oil dropped by 25% with both volumes sold and pricing falling.

Year over year, increased royalty and transportation costs per Boe were offset by lower per-Boe production costs per Boe. The lower per-Boe netback resulted from higher realized hedging losses. Compared to 2013, field netback per Boe fell by 2%. These year-over-year changes correspond to production growth from the Umbach property. Nevertheless, it should be recognized that lower crude oil production in total, and as a percentage of total Boe, reduces the contribution from a high-margin product and results in a lower netback per Boe.

Year-to-date netback per Boe prior to hedging adjustments was 4% higher than the previous year. Largely identical prices for crude oil and NGL were more than offset by higher natural gas prices which prevailed for the first three quarters of 2014. Lower production costs were partially offset by higher royalty and transportation costs.

Cash costs per Boe, comprising production costs, transportation, general and administrative costs and interest, amounted to $13.23 for 2014 compared to $16.24 for 2013. Year-over-year reductions per Boe in production, general and administrative and interest costs more than offset increases in royalty and transportation costs.

General and Administrative Costs

Total Costs	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year – before recoveries	$ 5,956	$ 5,347
Overhead recoveries	(2,144)	(1,390)
Charge for year – net of recoveries	$ 3,812	$ 3,957
Per Boe	$ 1.50	$ 2.98

Gross general and administrative costs for 2014 increased by 11% when compared to 2013. The year-on-year increase in general and administrative costs is largely attributable to increases in personnel and accommodation costs. Standard overhead recoveries increased as a result of increased capital spending at Umbach.

On a per-Boe measure, net general and administrative costs fell by 50% compared to 2013 as a result of increased production. The Company expects that increased production volumes in future periods will result in this favourable trend continuing, although general and administrative costs for the fourth and first quarters of a fiscal year tend to be higher due to the inclusion of year-end costs. However, there will be an offset, as lower levels of field activity expected in 2015 will result in lower recoveries.

Share-Based Compensation

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 2,192	$ 881
Per Boe	$ 0.86	$ 0.66

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 149% in 2014 compared to 2013. The year-over-year increase is attributable to the grant of 3,770,000 stock options in 2014. In the first quarter of 2014 grants of 1,742,000 stock options were made with a subsequent grant of 1,938,000 being made in the final quarter. In addition, 90,000 options were granted to new employees.

Depletion and Depreciation

	Year Ended December 31, 2014	Year Ended December 31, 2013
Depletion	$ 25,869	$ 17,396
Depreciation	3,623	1,539
Charge for year	$ 29,492	$ 18,935
Per Boe	$ 11.58	$ 14.26

Property and equipment assets 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 quarter by proved plus probable reserves at the beginning of the quarter. As a result, the considerable year-over-year increase in reserves at year end only benefits the fourth quarter of the year.

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 year over year. Year-over-year per-Boe charge fell by 19%, as reserves continued to grow at Umbach, reflecting Storm's successful drilling program.

Exploration and Evaluation Costs Expensed

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 1,427	$ 480
Per Boe	$ 0.56	$ 0.36

Exploration and evaluation costs expensed is a non-cash charge representing the cost of undeveloped lands with lease terms expiring in the period.

Accretion

	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 351	$ 223

Accretion represents the time value increase for the year of the Company's decommissioning liability.

Interest and Finance Costs

(000s)	Year Ended December 31, 2014	Year Ended December 31, 2013
Charge for year	$ 1,532	$ 1,194
Percentage of revenue from product sales	1.6%	2.4%
Per Boe	$ 0.60	$ 0.90

Compared to the prior year, interest costs in 2014 grew as a result of increased bank borrowings corresponding to an expanding business and asset base. The Company also incurred fees related to the syndication of the credit facility in the second quarter of 2014. Expected expanded use of the Company's credit facility in future quarters would result in increased interest costs. 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 the first quarter of 2014, the Company sold 1.0 million common shares of Chinook Energy Inc. ("Chinook") for proceeds of $1.5 million recognizing a gain of $0.3 million. In the second quarter of 2014, the Company sold 1.0 million common shares of Chinook for proceeds of $2.3 million for a gain of $1.2 million. No common shares of Chinook were sold in the second half of 2014.

Unrealized Revaluation Loss on Investment

In 2013 the Company recognized a loss of $0.8 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 since the holding was acquired in August 2010. As at December 31, 2014, the Company recorded a mark-to-market gain of $0.1 million in other comprehensive income.

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.

In the fourth quarter of both 2013 and 2014, after review of year-end external engineering reports, which included estimates of future cash flows and future prices, the Company reduced the carrying amounts of two CGUs. Effective December 31, 2014, the carrying amount of the Alberta CGU was reduced by an amount of $22.7 million: in 2013 the carrying amount of this CGU was reduced by $15.4 million. Also, in 2013, the carrying amount of the HRB CGU was reduced by $10.6 million.

The carrying amount of the Alberta CGU at December 31, 2014 was compared to estimated before tax future cash flows, discounted at a rate of 15% to 20% ("NPV15" and "NPV20") for the properties within the CGU which represents a multiple of approximately six times cash flow using current production and the forward strip for future commodity prices. The carrying amount exceeded estimated future cash flows by $22.7 million.

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 are due to the following:

- A decline in the price forecast used by InSite in the year-end reserve evaluation;
- Technical revisions reduced proved producing reserves by 128 Mboe, or 6% of the opening balance;
- Operating costs increased by 6% caused in part by increasing repair and maintenance costs.

The 2013 reduction in the carrying amount of the HRB CGU was due less to a lack of investment than to a year-over-year reduction in forecasted future prices for natural gas with the consequent reduction in estimates of the value of the reserves associated with the property. The carrying amount of this CGU was reduced by $10.6 million in 2013. Although the same considerations apply in 2014, there are no indicators of additional impairment. Further, a measurement of DPIIP and contingent resource associated with the Company's land position in HRB indicates that the carrying amount is conservative in the context of the total resource.

For the past two years Storm has focused investment on Umbach and reduced investment elsewhere. Investment in 2014 increased the before tax future cash flow discounted at 10% at Umbach by 176% (2013 - 213%) for proved plus probable reserves and Company wide by 117% (2013 - 60%). However, no recognition of the considerable increase in reserve valuation resulting from the year's successful drilling program at Umbach can be recognized in the Company's financial statements.

The imprecision of estimates of future revenue streams should be recognized and the reduction in the carrying amount is not an attempt to put a value on the properties of the CGUs affected.

Gain (Loss) on Disposal of Oil and Gas Properties

In the first quarter of 2013, the Company sold land and largely oil producing properties in Alberta and British Columbia, realizing a minor gain on disposition of $0.7 million, which was measured by applying proceeds on sale against the carrying amount of the properties. Proceeds on sale were initially used to reduce bank debt which was subsequently redrawn and used to fund development at Umbach. Disposals in 2014 were not significant.

Gain (Loss) on Commodity Price Contracts

The unrealized gain (loss) on commodity price contracts results from the mark-to-market valuation of the unexpired portion of hedging positions outstanding at the end of the reporting period. The non-cash unrealized gain was $14.2 million for the year ended December 31, 2014 and the realized loss for the year ended December 31, 2014 was $3.2 million. In 2013, the unrealized loss was $1.5 million and the realized loss was $36,000.

	Year Ended December 31, 2014		Year Ended December 31, 2013	
Realized gain (loss)				
Crude oil	$ (68)	$(0.46)/Bbl	$ (767)	$ (4.33)/Bbl
Natural gas	(3,130)	$(0.26)/Mcf	731	$ 0.13/Mcf
Total realized gain/(loss) - cash	$ (3,198)	$(1.26)/Boe	$ (36)	$ (0.03)/Boe

	Year Ended December 31, 2014		Year Ended December 31, 2013	
Unrealized gain (loss)				
Crude oil – change in fair value	$ 5,060	$34.25/Bbl	$ (215)	$ (1.21)/Bbl
Natural gas – change in fair value	9,108	$ 0.75/Mcf	(1,262)	$ (0.22)/Mcf
Total unrealized gain/(loss) - non-cash	$ 14,168	$ 5.56/Boe	$ (1,477)	$ (1.11)/Boe

Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been set up 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, 2014	Maximum Annual Deduction
Canadian oil and gas property expense	$ 65,000	10%
Canadian development expense	96,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	73,000	20% – 100%
Operating losses	136,000	100%
Other	5,000	20% – 100%
Total	$ 397,000	

Net Income (Loss)

	Year Ended December 31, 2014	Year Ended December 31, 2013
Net income (loss)	$ 4,855	$ (26,203)
Per share - basic	$ 0.04	$ (0.36)
Per share - diluted	$ 0.04	$ (0.36)

Excluding the reduction in the carrying amount of property and equipment and unrealized hedging gains and losses from the determination of net income (loss) for each of 2014 and 2013, the Company would have reported net income of $13.4 million in 2014 and $1.3 million in 2013, respectively $0.12 and $0.02 per share. These amounts are non-GAAP measurements of net income from the Company's core business before non-cash adjustments relating to impairment charges and potential income from hedges expiring in future years.

Other Comprehensive Income

Other comprehensive income comprises net income for the year plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. In the first half of 2013, Storm's other comprehensive income comprised adjustments to reflect the period-end mark-to-market valuation of listed securities. In subsequent reporting periods, IFRS required that mark-to-market declines in the value of such securities be included in the determination of income or loss for the period, while mark-to-market increases remain in other comprehensive income.

Listed Securities	Holding	Number of Shares[(1)]	Year Ended December 31, 2014	Year Ended December 31, 2013
Chinook Energy Inc.	Common Shares	1,000,000	$ 110	$ -
Other comprehensive income for year			$ 110	$ -

(1) Shares owned at December 31, 2014.

Non-GAAP Funds from Operations and Funds from Operations Per Share

	Year Ended December 31, 2014		Year Ended December 31, 2013	
		Per diluted share		Per diluted share
Funds from operations	$ 45,412	$ 0.41	$ 21,949	$ 0.30

Non-GAAP funds from operations for 2014 increased by 107% from the prior year. 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 follows.

Cash Flows from Operating Activities

	Year Ended December 31, 2014		Year Ended December 31, 2013	
		Per diluted share		Per diluted share
Non-GAAP funds from operations	$ 45,412	$ 0.41	$ 21,949	$ 0.30
Net change in non-cash working capital items	2,917	0.03	2,333	0.03
Cash from operating activities	$ 48,329	$ 0.44	$ 24,282	$ 0.33

The reconciling item between funds from operations and cash flows from operating activities is the change in non-cash operating working capital items.

Corporate Netbacks

($/Boe)	Year Ended December 31, 2014	Year Ended December 31, 2013
Revenue from product sales	37.48	37.34
Hedging losses	(1.26)	(0.03)
Royalties	(5.16)	(4.55)
Production	(9.33)	(10.86)
Transportation	(1.80)	(1.50)
General and administrative	(1.50)	(2.98)
Interest	(0.60)	(0.90)
Funds from operations netback	17.83	16.52
Share-based compensation	(0.86)	(0.66)
Depletion, depreciation and accretion	(11.72)	(14.43)
Exploration and evaluation costs expensed	(0.56)	(0.36)
Gain on disposal of investments	0.58	-
Unrealized revaluation loss on investments	-	(0.63)
Reduction of carrying amount of property and equipment	(8.91)	(19.58)
Gain (loss) on disposal of oil and gas properties	(0.02)	0.52
Unrealized gain (loss) on commodity price contracts	5.56	(1.11)
Net income (loss) per Boe	1.90	(19.73)

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the end of 2013, the bank facility credit limit was $65.0 million. In May and November 2014, the facility credit limit was increased to $90.0 million and $130.0 million respectively, in recognition of production and reserve growth at Umbach.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that net debt including working capital deficiency not exceed the facility credit limit.

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 major 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.

Investments

The Company owns listed shares as set out below, which are valued at the closing price on the TSX at December 31, 2014.

	Holding	Number of Shares	Exchange	Closing Price Dec. 31, 2014	Value at Dec. 31, 2014
Chinook Energy Inc.	Common Shares	1,000,000	TSX	$ 1.27	$ 1,270

In the first quarter of 2014, the Company sold 1.0 million shares of Chinook for net proceeds of $1.5 million and recognized a gain of $0.3 million. In the second quarter of 2014, the Company sold an additional 1.0 million shares for net proceeds of $2.3 million and recognized a gain of $1.2 million. There were no shares sold in the second half of 2014.

Capital Expenditures

During 2014, the Company spent $194.6 million, of which $107.0 million (2013 - $72.0 million) was spent on field operations almost exclusively to develop the high liquids content natural gas play at Umbach. In addition, $88.0 million was spent to acquire 29 sections of undeveloped land directly adjacent to Storm's 100% working interest lands at Umbach South, along with certain proved and probable reserves and two 100% working interest horizontal wells then producing 359 Boe net per day.

Major field capital outlays in 2014 include $68.1 million on drilling and completions and $34.3 million on facilities, equipping and tie-ins, all in the Umbach area.

	Year Ended December 31, 2014	Year Ended December 31, 2013
Land and lease	$ 1,763	$ 15,477
Drilling	37,620	19,003
Completions	30,469	16,478
Facilities, equipping and gathering	34,351	13,574
Recompletions and workovers	2,328	2,711
Proceeds on disposition of oil and gas properties	-	(19,495)
Property and facility acquisitions	87,951	4,529
Property acquisition adjustments, seismic and administrative assets	-	
Other	73	167
Total capital expenditures	$ 194,555	$ 52,444

Capital expenditures were allocated as follows:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Exploration and evaluation	$ 80,684	$ 15,468
Property and equipment	113,871	36,976
Total – net of dispositions	$ 194,555	$ 52,444

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, administrative and capital costs payable. 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, 2014 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. Changes in the amount of the liability during 2014 reflect (i) additional liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, iii) assessment of the amount of future costs and timing of incurrence of such costs, (iv) less the decommissioning obligations associated with dispositions of oil and gas properties, (v) 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 2.3%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation including monitoring actual abandonment and reclamation costs which is also supported by external information from industry sources and has regard to industry best practices, provincial and other regulation and evolution of same.

Shareholders' Equity

Details of share issuances from inception to December 31, 2014 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
Total		111,322	$ 3.19	$ 355,254

(1) Before share issue costs.

In April 2013 the Company entered into a bought deal financing for aggregate gross proceeds of $23,650,400. Pursuant to this financing, the Company issued 12,580,000 common shares at a price of $1.88 per share. Concurrently with the bought deal financing, the Company issued 3,000,000 common shares also at a price of $1.88 per share to certain directors, officers and employees of the Company for gross proceeds of $5,640,000. Both of these financings closed on May 1, 2013. Net proceeds received totaled $27.8 million.

In October 2013 the Company entered into a bought deal financing for aggregate gross proceeds of $30,150,000. Pursuant to this financing, the Company issued 9,000,000 common shares at a price of $3.35 per share. Concurrently with the bought deal financing, the Company issued 1,100,000 common shares, also at a price of $3.35 per share, to certain directors, officers and employees of the Company for gross proceeds of $3,685,000. Both of these financings closed on November 19, 2013. Net proceeds received totaled $31.9 million.

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 producing 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 $88.0 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 2014, stock options were exercised at an average price of $3.26 per optioned share and 1,709,666 common shares were issued for proceeds of approximately $5,580,000.

Issued and outstanding common shares at December 31, 2014 and February 26, 2015, the date of this MD&A, totaled 111,321,978.

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 agreements.

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 $28,300. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $29.0 million over the next four years.

FOURTH QUARTER RESULTS

Storm's summarized financial and operating results for the fourth quarter of 2014, compared to the fourth quarter of 2013, are as follows:

(Unaudited)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Percentage Change
Financial			
Production revenue ($000s) (1)	28,070	15,380	83%
Funds from operations ($000s)	13,892	7,501	85%
Per share – basic ($)	0.13	0.09	44%
Per share – diluted ($)	0.12	0.09	33%
Net loss ($000s)	(7,422)	(25,174)	N/A
Per share – basic ($)	(0.07)	(0.34)	N/A
Per share – diluted ($)	(0.07)	(0.34)	N/A
Capital expenditures – net ($000s)	20,219	11,380	78%
Debt, including working capital deficiency ($000s)	63,080	12,059	423%
Operations			
Boe production per day (6:1)	10,173	4,773	113%
Gas production per day (Mcf)	49,094	21,898	124%
NGL production per day (Bbls)	1,605	695	131%
Oil production per day (Bbls)	385	428	(10%)
Gross wells drilled	2.0	1.0	100%
Net wells drilled	2.0	1.0	100%

(1) Excludes 2014 hedging gains of $0.5 million (2013 – $40,000).

Production by Area

In the fourth quarter of 2014, average Boe per day volumes increased by 113% when compared to the fourth quarter of 2013, and by 42% when compared to the third quarter of 2014. Production of natural gas amounted to 80% of total Boe production in the fourth quarter of 2014, up from earlier quarters as a result of increased production from the tie-in of three new wells at Umbach.

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

Three Months Ended December 31, 2013				
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	15,797	629	-	3,262
Horn River Basin – NE BC	2,176	-	-	363
Grande Prairie Area – AB	3,925	66	428	1,148
Total	21,898	695	428	4,773

Three Months to September 30, 2014				
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	28,344	1,099	-	5,823
Horn River Basin – NE BC	1,907	-	-	318
Grande Prairie Area – AB	3,423	55	394	1,019
Total	33,674	1,154	394	7,160

Daily production per million shares outstanding at the end of the quarter averaged 91 Boe per day compared to 55 Boe per day for the fourth quarter of 2013 and 64 Boe per day in the immediately preceding quarter. Removal of capacity constraints through construction of a new facility in the third quarter of 2014 was the primary reason for the fourth quarter production increase.

Revenue from Product Sales

(000s)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Natural gas (Mcf/d)	$ 17,369	$ 7,807	$ 13,869
Natural gas liquids (Bbls/d)	8,292	4,483	7,758
Crude oil (Bbls/d)	2,409	3,090	3,275
Total (Boe/d)	$ 28,070	$ 15,380	$ 24,902

Revenue from product sales for the fourth quarter of 2014 increased by 83% when compared to the fourth quarter of 2013 and increased by 13% when compared to the immediately preceding quarter. However, quarterly production volumes grew 113% year over year and by 42% when compared to the immediately preceding quarter. The disparity between growth in production and in revenue corresponds to price declines, as follows:

Realized Prices per Commodity Unit	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Natural gas (Mcf/d)	$ 3.85	$ 3.88	$ 4.48
Natural gas liquids (Bbls/d)	$ 56.15	$ 70.10	$ 73.09
Crude oil (Bbls/d)	$ 68.01	$ 78.47	$ 90.31
Total (Boe/d)	$ 29.99	$ 35.02	$ 37.80

Hedging

Realized hedging gains during the fourth quarter totaled $0.5 million which added $0.52 per Boe to the field netback, compared to a realized gain of $40,000 for the same quarter of 2013 and a loss of $0.8 million for the third quarter of 2014.

Royalties

(000s)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Charge for period	$ 3,455	$ 1,161	$ 3,943
Percentage of revenue from product sales	12.3%	7.5%	15.8%
Per Boe	$ 3.69	$ 2.64	$ 5.99

Royalties for the fourth quarter of 2014 increased by 198% when compared to the same quarter of 2013 and decreased by 12% compared to the third quarter of 2014. In the fourth quarter of 2014, royalties benefited from a British Columbia infrastructure credit of $0.3 million relating to the HRB. Lower per-commodity-unit pricing also resulted in lower royalties in the fourth quarter of 2014.

At Umbach, future production will continue to benefit from British Columbia's Infrastructure Royalty Credit Program. For 2015 and beyond, $5.7 million in credits have been approved for completed projects and will be released once incremental royalty revenue is generated (dependent on commodity prices). Approved credits will be used to reduce royalties payable on production from horizontal wells associated with the projects that have been approved under the Infrastructure Royalty Credit Program. Approval of royalty credits for future projects is uncertain and, correspondingly, timing of receipt of future royalty credits is difficult to forecast.

Production Costs

(000s)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Charge for period	$ 7,864	$ 4,273	$ 6,279
Percentage of revenue from product sales	27.9%	27.8%	25.2%
Per Boe	$ 8.40	$ 9.73	$ 9.53

Production costs for the quarter increased by 84% when compared to the final quarter of 2013 and by 25% when compared to the third quarter of 2014. The increase in production costs is largely aligned with increased production at Umbach. Quarter over quarter, production costs per Boe have declined steadily, in part due to production growth, a trend that should continue in future quarters, although circumstances such as winter conditions or equipment failures can result in unanticipated additional costs being incurred.

Transportation Costs

(000s)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Charge for period	$ 1,791	$ 801	$ 1,111
Percentage of revenue from product sales	6.4%	5.2%	4.5%
Per Boe	$ 1.91	$ 1.82	$ 1.69

Transportation costs for the final quarter of 2014 increased by 123% over the same quarter of 2013, and increased 61% over the immediately preceding quarter. Higher volumes of field condensate at Umbach resulted in increased NGL trucking charges. In addition, when compared to the immediately prior quarter, increased costs in the final quarter of 2014 were due to higher oil trucking charges in Alberta and pipeline restrictions resulting in higher condensate trucking charges at Umbach.

Field Netbacks

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

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 income 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

Three Months Ended December 31, 2013	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 3.88	$ 70.10	$ 78.47	$ 35.02
Royalties	(0.02)	(5.03)	(20.52)	(2.65)
Production costs	(1.88)	-	(12.53)	(9.73)
Transportation costs	(0.20)	(2.77)	(5.44)	(1.82)
Field operating income before hedging	$ 1.78	$ 62.30	$ 39.98	$ 20.82
Realized hedging gains (losses)	0.10	-	(4.01)	0.09
Total operating income per commodity unit	$ 1.88	$ 62.30	$ 35.97	$ 20.91
Total operating income (000s)	$ 3,785	$ 3,983	$ 1,417	$ 9,185

Three Months Ended September 30, 2014	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 4.48	$ 73.09	$ 90.31	$ 37.80
Royalties	(0.52)	(14.24)	(22.79)	(5.99)
Production costs	(1.72)	-	(25.91)	(9.53)
Transportation costs	(0.19)	(3.18)	(4.87)	(1.69)
Field operating income before hedging	$ 2.05	$ 55.67	$ 36.74	$ 20.59
Realized hedging losses	(0.19)	-	(4.95)	(1.17)
Total operating income per commodity unit	$ 1.86	$ 55.67	$ 31.79	$ 19.42
Total operating income (000s)	$ 5,736	$ 5,909	$ 1,153	$ 12,798

Total operating income for the final quarter of 2014 was 68% higher than the same quarter of 2013 due to higher production volumes partially offset by lower oil and NGL prices. Compared to the third quarter of 2014, lower royalties and production costs were more than offset by lower pricing for all commodities as well as higher transportation costs, resulting in a netback-per-Boe decrease of 15%. Compared to the same quarter in 2013, all commodity prices decreased and, combined with the effect of increased lower netback natural gas production which increased from 76% to 80% of total corporate volumes, the year-over-year per-Boe selling price was lower by $5.03. The fourth quarter of 2014 benefited from hedging gains of $0.52 per Boe.

Cash costs per Boe, comprising production costs, transportation, interest and general and administrative costs, amounted to $11.97 for the final quarter of 2014, $15.38 for the equivalent quarter of 2013 and $12.76 for the third quarter of 2014. In the fourth quarter of 2014, per-Boe reductions in production, interest and general and administrative costs more than offset transportation cost increases when compared to both prior periods.

General and Administrative Costs

Total Costs	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Charge for period – before recoveries	$ 1,581	$ 1,740	$ 1,278
Overhead recoveries	(498)	(312)	(634)
Charge for period – net of recoveries	$ 1,083	$ 1,428	$ 644
Per Boe	$ 1.16	$ 3.25	$ 0.98

Gross general and administrative costs for the final quarter of 2014 decreased by 9% when compared to the final quarter of 2013 and increased by 24% compared to the third quarter of 2014. The year-on-year decrease in general and administrative costs is largely attributable to lower personnel costs. The increase in the final quarter of 2014, when compared to the third quarter, is due to the inclusion in the final quarter of certain costs related to the Company's year end, including external services. Further, overhead recoveries in the final quarter of 2014 fell due to capital expenditures declining by 34% when compared to the third quarter.

On a per-Boe measure, net general and administrative costs fell by 64% compared to the same quarter in 2013 due to increased production. The Company expects that increased production volumes in future periods will result in this favourable trend continuing.

Share-Based Compensation

Share-based compensation increased by 248% in the final quarter of 2014 compared to the same quarter of 2013 and increased by 24% when compared to the third quarter of 2014. The increase in share-based compensation is attributable to the grant of 3.8 million new stock options in 2014.

Depletion and Depreciation

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Depletion	$ 8,965	$ 5,218	$ 6,587
Depreciation	1,155	494	1,021
Charge for period	$ 10,120	$ 5,712	$ 7,608
Per Boe	$ 10.81	$ 13.01	$ 11.55

Higher production resulted in the total charge for depletion and depreciation increasing year over year by 77% in the final quarter of 2014. Compared to the immediately prior quarter, the charge for the fourth quarter of 2014 increased by 33%, with higher production being offset by a decrease in the per-unit rate resulting from the application of the 2014 year-end reserve report to reset the depletion calculation for the final quarter of the year. The increase in the year-over-year charge for depreciation is a consequence of increased investment in facilities in 2014.

The year-over-year per-Boe charge fell by 17%, a reflection of lower cost reserve additions resulting from the Company's successful 2014 drilling program.

Reduction of Carrying Amount of Property and Equipment

As more fully described on page 28, in the last quarter of 2014 the Company reduced the carrying amount of the Alberta CGU. The amount of the reduction in the carrying amount, $22.7 million (2013 - $26.0 million), was included in the consolidated statement of loss for the quarter.

Accretion

The increased year-over-year change for accretion is due to additional liabilities assumed due to drilling, acquisitions and facility construction. The increase in accretion expense between the third and fourth quarters of 2014 was due to changes in estimates of future costs and discount rates.

Interest

(000s)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Charge for period	$ 470	$ 256	$ 370
Percentage of revenue from product sales	1.7%	1.7%	1.0%
Per Boe	$ 0.50	$ 0.58	$ 0.56

Interest costs for the final quarter of 2014 increased by 84% compared to the equivalent period in 2013, as a result of increased bank borrowings corresponding to an expanding business and asset base. Interest costs also increased by 27% compared to the third quarter of 2014 as borrowings increased and the Company incurred fees related to the increase in the bank line from $90.0 million to $130.0 million.

Net Income (Loss)

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Net income (loss)	$ (7,422)	$ (25,174)	$ 5,473
Per basic and diluted share	$ (0.07)	$ (0.34)	$ 0.05

Excluding the reduction in the carrying amount of property and equipment and unrealized hedging gains and losses, net income in the fourth quarter of 2014 would have amounted to $1.8 million, or $0.01 per diluted share. Similar adjustments to the net loss reported for the final quarter of 2013 results in normalized net income of $2.1 million.

Other Comprehensive 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 three months ended December 31, 2014, a loss of $0.8 million was recognized in other comprehensive income, representing the mark-to-market decrease in value of the investment in Chinook measured against the value at the end of the third quarter of 2014.

Non-GAAP Funds from Operations and Funds from Operations Per Share

	Three Months Ended December 31, 2014		Three Months Ended December 31, 2013		Three Months Ended September 30, 2014	
		Per diluted share		Per diluted share		Per diluted share
Funds from operations	$ 13,892	$ 0.12	$ 7,501	$ 0.09	$ 11,784	$ 0.11

Non-GAAP funds from operations for the fourth quarter of 2014 increased by 85% from the fourth quarter of 2013, and increased by 18% compared to the third quarter 2014.

Non-GAAP funds from operations is not a measure recognized by GAAP in Canada. The most directly comparable measure under GAAP is cash flows from operating activities, as set out below.

Cash Flows from Operating Activities

	Three Months Ended December 31, 2014		Three Months Ended December 31, 2013		Three Months Ended September 30, 2014	
		Per diluted share		Per diluted share		Per diluted share
Non-GAAP funds from operations	$ 13,892	$ 0.12	$ 7,501	$ 0.09	$11,784	$ 0.11
Net change in non-cash working capital items	3,579	0.03	(550)	(0.01)	(1,081)	(0.01)
Cash from operating activities	$ 17,471	$ 0.15	$ 6,951	$ 0.08	$10,703	$ 0.10

Non-GAAP funds from operations differs from cash flows from operating activities by the amount of the change in non-cash working capital between the end of the third and fourth quarters.

Capital Expenditures

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Land and lease	$ 342	$ 473	$ 567
Drilling	4,240	3,925	6,644
Completions	8,149	3,548	4,844
Facilities, equipping and gathering	7,488	2,654	17,479
Recompletions and workovers	-	816	867
Proceeds on disposition of oil and gas properties	-	-	-
Property and facility acquisitions	-	-	-
Property acquisition adjustments, seismic and administrative assets	(124)	(36)	25
Total capital expenditures	$ 20,095	$ 11,380	$ 30,426

Capital expenditures in the reporting period were allocated as follows:

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Three Months Ended September 30, 2014
Exploration and evaluation	$ 637	$ 901	$ 245
Property and equipment	19,458	10,479	30,181
Total – net of dispositions	$ 20,095	$ 11,380	$ 30,426

Quarterly Results

Summarized information by quarter for the two years ended December 31, 2014 appears below:

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production revenue ($000s)(1)	28,556	24,131	20,202	19,393	15,420	13,093	11,960	9,069
Non-GAAP funds from operations ($000s)(2)	13,892	11,784	11,076	8,660	7,501	6,144	5,077	3,227
Per share								
- basic ($)	0.13	0.11	0.10	0.09	0.09	0.08	0.07	0.05
- diluted ($)	0.12	0.11	0.10	0.08	0.09	0.08	0.07	0.05
Net income (loss) ($000s)	(7,422)	5,473	6,598	206	(25,174)	(1,429)	661	(261)
Per share								
- basic ($)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)	0.01	0.00
- diluted ($)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)	0.01	0.00
Net capital expenditures ($000s)	20,095	30,426	33,640	110,394	11,380	23,717	16,710	637
Average daily production - Boe	10,173	7,160	5,462	5,068	4,773	3,800	3,460	2,488
Net debt ($000s)(3)	63,080	56,157	41,837	22,176	12,059	40,968	22,671	42,106

(1) Includes hedging gains and losses.
(2) See Non-GAAP Measurements on page 19 of this MD&A.
(3) Includes investments and working capital deficiency and excludes the fair value of commodity price contracts.

SELECTED ANNUAL FINANCIAL INFORMATION

	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
Production revenue ($000s)[1]	92,282	49,542	33,979
Funds from operations ($000s)	45,412	21,949	13,387
Per share – basic ($)	0.42	0.30	0.24
Per share – diluted ($)	0.41	0.30	0.24
Net income (loss) ($000s)	4,855	(26,203)	(6,574)
Per share – basic ($)	0.04	(0.36)	(0.12)
Per share – diluted ($)	0.04	(0.36)	(0.12)
Total assets ($000s)	418,568	250,550	248,792
Debt, including working capital deficiency ($000s)	63,080	12,059	40,376
Average daily production (Boe)	6,980	3,637	2,254
Field netback ($/Boe)[1]	19.93	20.40	23.24

(1) Includes hedging gains and losses.

Share Trading

Set out below is share trading activity for Storm for 2014 and 2013.

	2014					2013				
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	4.95	5.75	6.10	6.16	6.16	2.15	2.70	3.80	4.26	4.26
Low ($)	3.82	4.66	4.30	3.37	3.37	1.45	1.87	2.60	3.29	1.45
Close ($)	4.71	5.28	5.77	4.14	4.14	2.10	2.70	3.57	4.05	4.05
Volume traded (000s)	17,385	19,825	23,486	26,556	87,253	2,805	8,527	6,134	5,596	23,062
Value traded ($000s)	76,088	103,659	124,400	132,420	436,567	5,039	17,894	20,015	20,375	63,323
Weighted average trading price ($)	4.38	5.23	5.30	4.99	5.00	1.80	2.10	3.27	3.65	2.75

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the audited consolidated financial statements for the year ended December 31, 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 using information which may involve an element of measurement uncertainty. Variations between amounts estimated and included in the financial statements and actual results subsequently realized could have a material effect on Storm's operating results and financial position.

Accounting for Acquisitions

Acquisitions completed in 2014 and in earlier reporting periods necessitated the allocation of fair values to the assets acquired and the liabilities assumed. The determination of fair values was made by management of Storm and involved measurements, estimations and judgments which could differ from similar determinations made by other parties. Further, fair values were set using management's knowledge of the assets and liabilities of the acquired assets or companies at the time of acquisition or subsequently, and information and circumstances may emerge that could result in changes to the fair values set by management. The allocation of fair values thus involves measurement uncertainty and changes thereto could have a material effect on operating results and financial position.

Accounts Payable and Accrued Liabilities

At the end of each reporting period, 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 the cost of such unbilled services and materials 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 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 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 obligation.

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. The decommissioning liability reflects estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of the costs to be incurred in future periods. 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.

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. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

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.

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 are expensed if the Company determines that the costs incurred will yield no future economic benefit. The amounts transferred to property and equipment, or written off, 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

Generally, upon commencement of production, the Company transfers from exploration and evaluation assets to property and equipment assets on the Company's statement of financial position an amount representing the accumulated net costs associated with the property. 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 assets 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 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 such reserves. Further, property and equipment is subject each reporting period to an impairment test under which the carrying amount of property and equipment, as allocated to CGUs, is compared to the greater of its value in use and its fair value plus costs to sell. All of these involve assumptions regarding future events and circumstances and involve a high degree of uncertainty.

RISK ASSESSMENT

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 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 to generate and test exploration ideas. Further, drilling and completing a well may not result in the discovery of economic reserves. Storm endeavours to minimize this risk by ensuring that:

- Where possible, prospects have multi-zone potential, or zones have a large pay column;
- 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 maintains a high working interest. The Company can thus control the timing, cost and technical content of its exploration and development programs.

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 re-investment capacity, and hence ultimate growth potential and profitability. Low prices will also limit access to capital, both equity and debt. The Company may mitigate 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. In addition, natural gas and associated liquids is an increasingly high percentage of total Company production, a trend unlikely to change in future years, resulting in increasing 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, new wells tend to produce at high initial rates followed by rapid declines until a flattening decline profile emerges. There is a risk that the sustainable decline profile which eventually emerges for newly drilled wells is sub-economic. In addition, the Company's properties at Umbach and the HRB are 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 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 largely remote and relatively undeveloped and, particularly the HRB in northeast British Columbia, are climatically hostile. 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.

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. In addition, the Company's approach to property development frequently 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, 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 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

High levels of field activity can result in shortages of services, products, equipment, or manpower in many or all necessary 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 mitigate such risks through careful management of key supplier relationships. Declines in commodity prices should result in lower service costs; however, these may be offset by service providers choosing to retire equipment rather than operate at sub-optimum prices.

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 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, particularly when cash flow for any period is anticipated to be lower than capital expenditures. Generally, capital programs are financed from cash flow and disciplined use of debt. Failure to develop producing wells and to 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 dilutive to existing shareholders. In addition, future 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 program and the timing of expenditures.

Acquisitions

The Company's objectives are, in part, supported through carefully selected and managed acquisitions. Acquisitions have to be acceptably priced and production should provide acceptable netbacks, or provide identifiable opportunities to increase value. In the current pricing environment, natural gas properties providing a reasonable netback are difficult to identify. An acquisition should also offer potential for near and medium term development and be in areas where the Company can readily add to the acquired land position. Processing and transportation infrastructure must also be in place, or within the Company's financial capacity to construct or acquire.

Acquisitions in 2012 and in the first quarter of 2014 involved assumptions about future revenues, costs, operations and reserves and growth opportunities which have been and will continue to be invalidated by circumstances. The acquisition completed in 2014 comprised production and undeveloped land contiguous to the Company's existing lands at Umbach. This serves to mitigate, but not eliminate, development risk.

In addition, acquired assets must compete for investment capital with existing Company properties, which may result in postponement of development programs on acquired or existing properties.

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 development and operating 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 and finding and development 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 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, will be closed for maintenance in the second quarter for an estimated period of 35 days.

Storm's contracted gas processing capacity at third party facilities is approximately 35% of total raw gas production in the fourth quarter of 2014 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.

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.

The majority of Storm's natural gas production in northeast British Columbia is subject to the AECO – BC Stn 2 differential which has fluctuated between +$0.48 per GJ and -$0.85 per GJ over the last five years (average was -$0.62 per GJ in 2014).

Storm has contracted pipeline transportation capacity for approximately 45% of total natural gas sales volumes in the fourth quarter of 2014 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.

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 same concern applies to the Federal government. Federal corporate tax rates are low by international standards and are thus vulnerable to upward adjustment for electoral purposes.

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 so-called black swan events.

FINANCIAL REPORTING UPDATE

Accounting Changes

Levies

Effective January 1, 2014 the Company adopted IFRIC 21 Levies, which clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. No liability should be recognized before the specified minimum threshold to trigger that levy is reached. The Company concluded that the application of the standard has no material effect on its financial statements.

Future Accounting Policies

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, 2017.

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.

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 26, 2015

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, 2014 and 2013, 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, 2014 and 2013 and its financial performance and its cash flows for the years then ended, in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 26, 2015

Consolidated Statements of Financial Position

(Canadian $000s)	December 31, 2014	December 31, 2013
ASSETS		
Current		
Accounts receivable	$ 8,205	$ 6,185
Prepaids and deposits	905	1,017
Investments (Note 4)	1,270	3,480
Fair value of commodity price contracts (Note 13)	12,920	-
	23,300	10,682
Exploration and evaluation (Note 5)	126,805	87,396
Property and equipment (Note 6)	268,463	152,472
	$ 418,568	$ 250,550
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 27,430	$ 12,114
Fair value of commodity price contracts (Note 13)	-	1,248
	27,430	13,362
Bank indebtedness (Note 7)	46,030	10,627
Decommissioning liability (Note 8)	23,553	8,689
	97,013	32,678
Shareholders' equity		
Share capital (Note 10)	351,161	252,837
Contributed surplus (Note 11)	3,363	2,969
Deficit	(33,079)	(37,934)
Accumulated other comprehensive income	110	-
	321,555	217,872
Commitments (Note 17)		
	$ 418,568	$ 250,550

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director

Director

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

(Canadian $000s except per-share amounts)	Year Ended December 31, 2014	Year Ended December 31, 2013
Revenue		
Revenue from product sales	$ 95,480	$ 49,578
Realized loss on commodity price contracts (Note 13)	(3,198)	(36)
Royalties	(13,151)	(6,035)
	$ 79,131	$ 43,507
Expenses		
Production	23,781	14,414
Transportation	4,594	1,993
General and administrative	3,812	3,957
Share-based compensation (Note 11)	2,192	881
Depletion and depreciation	29,492	18,935
Reduction in carrying amount of property and equipment (Note 6)	22,700	26,000
Exploration and evaluation costs expensed (Note 5)	1,427	480
Accretion	351	223
	88,349	66,883
Income (loss) before the following:	(9,218)	(23,376)
Interest and finance costs	(1,532)	(1,194)
Gain on disposal of investments (Note 4)	1,486	-
Unrealized revaluation loss on investments (Note 4)	-	(840)
Gain (loss) on disposal of oil and gas properties (Note 6)	(49)	684
Unrealized gain (loss) on commodity price contracts (Note 13)	14,168	(1,477)
Net income (loss) for the year	4,855	(26,203)
Other comprehensive income (loss)		
Reversal of prior year unrealized loss on investments (Note 4)	110	-
Other comprehensive income	110	-
Comprehensive income (loss) for the year	$ 4,965	$ (26,203)
Net income (loss) per share (Note 12)		
- basic	$ 0.04	$ (0.36)
- diluted	$ 0.04	$ (0.36)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(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 10)	98,355	-	-	-	98,355
Share issue costs (Note 10)	(1,829)	-	-	-	(1,829)
Share-based compensation (Note 11)	-	2,192	-	-	2,192
Transfer of share-based compensation on options exercised (Note 10)	1,798	(1,798)	-	-	-
Reversal of prior period unrealized loss on investments (Note 4)	-	-	-	110	110
Balance, end of year	$ 351,161	$ 3,363	$ (33,079)	$ 110	$ 321,555

(Canadian $000s)				Year Ended December 31, 2013	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of year	$ 193,184	$ 2,088	$ (11,731)	$ -	$ 183,541
Net loss for the year	-	-	(26,203)	-	(26,203)
Issue of common shares (Note 10)	63,075	-	-	-	63,075
Share issue costs (Note 10)	(3,422)	-	-	-	(3,422)
Share-based compensation (Note 11)	-	881	-	-	881
Balance, end of year	$ 252,837	$ 2,969	$ (37,934)	$ -	$ 217,872

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Year Ended December 31, 2014	Year Ended December 31, 2013
Operating activities		
Net income (loss) for the year	$ 4,855	$ (26,203)
Non-cash items:		
Share-based compensation (Note 11)	2,192	881
Depletion, depreciation and accretion	29,843	19,158
Reduction in carrying amount of property and equipment (Note 6)	22,700	26,000
Exploration and evaluation costs expensed (Note 5)	1,427	480
Gain on disposal of investments (Note 4)	(1,486)	-
Unrealized revaluation loss on investments (Note 4)	-	840
(Gain) loss on disposal of oil and gas properties (Note 6)	49	(684)
Unrealized loss (gain) on commodity price contracts (Note 13)	(14,168)	1,477
	45,412	21,949
Net change in non-cash working capital items (Note 16)	2,917	2,333
	48,329	24,282
Financing activities		
Proceeds from issue of common shares – net of expenses (Note 10)	38,601	59,653
Increase (decrease) in bank indebtedness	35,403	(31,085)
	74,004	28,568
Investing activities		
Additions to exploration and evaluation assets (Note 5)	(1,754)	(16,863)
Additions to property and equipment (Note 6)	(104,850)	(55,076)
Cash portion of acquisitions of property and equipment and exploration and evaluation assets (Notes 5 and 6)	(30,026)	-
Proceeds on disposal of exploration and evaluation assets	-	1,395
Proceeds on disposal of property and equipment (Note 6)	-	18,100
Proceeds on disposal of investments (Note 4)	3,806	-
Net change in non-cash working capital items (Note 16)	10,491	(406)
	(122,333)	(52,850)
Change in cash during the year	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2014 and 2013

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.

These financial statements were authorized for issue by the Board of Directors on February 26, 2015.

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 13.

Accounting Policies Adopted in 2014

Levies

Effective January 1, 2014, the Company adopted IFRIC 21 Levies, which clarifies that an entity recognizes a liability for a levy when the activity that triggers payment occurs. A levy comprises payments, other than income taxes, asset purchases and fines or penalties, to all levels of government and government agencies. No liability should be recognized before the specified minimum threshold to trigger that levy is reached. The Company concluded that the application of the standard has no material effect on the Company’s financial statements.

Future Accounting Policies

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, 2017.

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.

Oil and Gas Exploration and Evaluation Expenditures

Oil and gas 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 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 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 assets 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 asset group 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 6.

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 as part of depreciation and depletion. Subsequent to the initial measurement, 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.

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).

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 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 their intended use. All other borrowing costs are recognized as interest expense 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 common shares 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 those 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:

Reserves

The amounts recorded for depletion and depreciation 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 or recovery rates 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 5 - Classification and carrying amount of exploration and evaluation assets

Each reporting period, exploration and evaluation assets are subject to an impairment review, conducted internally, corresponding to the Company's view as to the recoverability of the asset. 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.

Note 6 – 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 investment capital.

Note 8 - 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 9 – 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. The Company does not recognize any tax asset due to uncertainty as to future realization.

Note 11 – 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 is potentially replaceable by a pricing model producing different results.

Note 13 – 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. INVESTMENTS

	December 31, 2014	December 31, 2013
Chinook Energy Inc. ("Chinook")	$ 1,270	$ 3,480

The investment in Chinook was transferred to Storm from a predecessor company in August 2010 and at December 31, 2014 the Company held a total of 1.0 million common shares (December 31, 2013 – 3.0 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.

Unrealized revaluation gain (loss) for the year ended December 31, 2014, in the amount of $0.1 million (2013 – loss of $0.8 million charged against net income) was recognized in other comprehensive income (loss).

5. EXPLORATION AND EVALUATION

	December 31, 2014	December 31, 2013
Balance, beginning of year	$ 87,396	$ 72,947
Acquisitions	78,930	-
Additions	1,754	16,863
Disposals	-	(755)
Exploration and evaluation expenditures expensed	(1,427)	(480)
Future decommissioning costs	3,476	812
Transfer to property and equipment	(43,324)	(1,991)
Balance, end of year	$ 126,805	$ 87,396

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 $78.9 million allocated to the purchase of the undeveloped land and $9.0 million to the purchase of production and reserves. This transaction did not constitute a business combination under IFRS.

6. PROPERTY AND EQUIPMENT

	December 31, 2014	December 31, 2013
Net book value, beginning of year	$ 152,472	$ 161,665
Cost		
Balance, beginning of year	$ 211,024	$ 176,990
Acquisitions	8,972	-
Additions	104,850	55,076
Disposals	-	(19,763)
Future decommissioning costs	11,037	(3,270)
Transfer from exploration and evaluation assets	43,324	1,991
Balance, end of year	$ 379,207	$ 211,024
Accumulated depletion and depreciation		
Balance, beginning of year	$ (58,552)	$ (15,325)
Depletion and depreciation	(29,492)	(18,935)
Reduction in carrying amount of property and equipment	(22,700)	(26,000)
Disposals	-	1,708
Balance, end of year	$ (110,744)	$ (58,552)
Net book value, end of year	$ 268,463	$ 152,472

During 2013 the Company sold certain land and oil and gas properties producing approximately 300 Boe per day, primarily light crude oil, for net proceeds of $19.5 million ($18.1 million related to property and equipment and $1.4 million related to exploration and evaluation).

As set out in Note 3, Significant Accounting Policies – Property and Equipment, at the end of each reporting period the Company reviews the carrying amounts of individual CGUs for indications of impairment. The most important indicator of impairment was a reduction in forecasted future commodity prices. At December 31, 2014, 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 CGU 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 year-end value of reserves plus estimated values for undeveloped land indicated that the carrying amounts of the Company's Alberta oil and gas CGU exceeded its fair value by $22.7 million. The inputs used in this valuation are determined to be Level 3 as they are not based on observable market data. Property and equipment on the Company's consolidated statement of financial position at December 31, 2014 has been reduced by this amount with the reduction being included in the consolidated statement of income (loss). At December 31, 2013, the comparison of the year-end carrying amount to estimated future cash flows, using a discount rate of 10%, resulted in the carrying amounts of two non-core CGUs (Alberta oil properties and the HRB natural gas property) being reduced by $26.0 million.

7. BANK INDEBTEDNESS

As at December 31, 2014, the Company had an extendible syndicated revolving bank facility in the amount of $130.0 million (December 31, 2013 – $65.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 30, 2015. At that time 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, 2014, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that net debt including working capital deficiency not exceed the facility amount.

8. 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 $37.3 million, which is expected to be paid over the next 25 years. A risk-free discount rate of 2.3% (2013 – 3.0%) and an inflation rate of 2.0% (2013 – 1.2%) was used to calculate the present value of the decommissioning obligation, amounting to $23.6 million.

The following table provides a reconciliation of the carrying amount of the obligation associated with the decommissioning of oil and gas properties:

	Year Ended December 31, 2014	Year Ended December 31, 2013
Balance, beginning of year	$ 8,689	$ 10,924
Obligations incurred	3,797	997
Obligations acquired	710	-
Obligations disposed	-	(2,515)
Obligations settled	(34)	(397)
Change in rate estimates(1)	6,029	(543)
Change in cost estimates(2)	4,011	-
Accretion expense	351	223
Balance, end of year	$ 23,553	$ 8,689

(1) Relates to changes in the inflation rate and discount rate in 2014 and a change in the discount rate in 2013.
(2) Cost estimates were adjusted based on actual costs for abandonments and reclamations.

9. 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 property and equipment assets, exploration and evaluation assets, 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 assets of approximately $261.0 million as well as non-capital losses of approximately $136.0 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, 2014	Year Ended December 31, 2013
Income (loss) for the year	$ 4,855	$ (26,203)
Statutory combined federal and provincial income tax rate	25%	25.0%
Expected income tax expense (recovery)	$ 1,214	$ (6,550)
Add (deduct) the income tax effect of:		
Share-based compensation	548	220
Change in unrecorded deferred income tax asset	(1,652)	5,492
Change in estimated tax pool balances	(47)	481
Other	(63)	357
Deferred income taxes	$ -	$ -

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

	As at December 31, 2014	As at December 31, 2013
Deferred tax assets:		
Non-capital losses	$ 34,310	$ 29,525
Decommissioning liability	5,888	2,172
Share issue costs	934	835
Investment	131	435
	$ 41,263	$ 32,967
Deferred tax liabilities:		
Property and equipment	(34,760)	(19,379)
Fair value of commodity price contracts	(3,542)	-
	$ (38,302)	$ (19,379)

10. 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

Common shareholders are entitled to receive dividends if, as and when declared by the Board of Directors. In the event of liquidation, dissolution or winding up of the Company, common shareholders shall, subject to the priority of creditors and any preferred shareholders, participate in any distribution in equal amounts per share.

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2012	61,824	$ 193,184
Shares issued pursuant to private placement(1)	15,580	29,290
Shares cancelled	(21)	(50)
Shares issued pursuant to private placement(2)	10,100	33,835
Share issue costs(1)(2)	-	(3,422)
Balance as at December 31, 2013	87,483	$ 252,837
Shares issued pursuant to Umbach acquisition(3)	13,629	57,925
Shares issued pursuant to private placement(4)	8,500	34,850
Share issue costs(4)	-	(1,829)
Shares issued from stock option exercises(5)	1,710	7,378
Balance as at December 31, 2014	111,322	$ 351,161

(1) On May 1, 2013 the Company issued, under private placement agreements, 15,580,000 common shares at a price of $1.88 per share for proceeds of $29.3 million before issue costs of approximately $1.5 million.

(2) On November 19, 2013 the Company issued, under private placement agreements, 10,100,000 common shares at a price of $3.35 per share for proceeds of $33.8 million before issue costs of approximately $1.9 million.

(3) On January 31, 2014 the Company issued 13,629,442 common shares, with a deemed value of $4.25 per common share, for proceeds 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. (See Note 5)

(4) 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.

(5) 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.

11. 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, a total of 11,132,197 common shares are available for issuance. At December 31, 2014, and at the date of this report, options in respect of 5,956,834 common shares were issued, all of which are unexercised, and options remained in respect of 5,175,363 common shares which are available for further grants under the stock option plan.

Details of the options outstanding at December 31, 2014 and December 31, 2013 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2012	2,723	$ 2.96
Granted during the year	1,499	$ 1.75
Forfeited during the year	(325)	$ 3.23
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
Number exercisable at December 31, 2014	954	$ 1.90

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	2,147	1.9	$ 1.83	927	$ 1.86
$2.64 - $3.96	40	1.2	$ 3.04	27	$ 3.04
$3.97 - $5.20	3,770	3.6	$ 4.52	-	$ -
Total	5,957	2.9	$ 3.54	954	$ 1.90

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, 2014 of $1.88 per share (2013 - $0.82 per share) include the following:

	2014	2013
Share price	$4.31 - $5.20	$ 1.75
Exercise price	$4.31 - $5.20	$ 1.75
Volatility	54% - 56%	63%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Dividends	-	-
Risk-free interest rate	1.2% - 1.4%	1.3%

Share-based compensation expense of $2,192,000 was charged to the consolidated statement of income (loss) during the year ended December 31, 2014 (2013 - $881,000) 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.

12. NET INCOME (LOSS) PER SHARE

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

	Year Ended December 31, 2014	Year Ended December 31, 2013
Net income (loss) for the year	$ 4,855	$ (26,203)
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	87,483	61,824
Effect of shares issued	20,689	11,567
Weighted average number of common shares outstanding – basic	108,172	73,391
Effect of outstanding options	1,809	-
Weighted average number of common shares outstanding - diluted	109,981	73,391
Net income (loss) per share		
- basic	$ 0.04	$ (0.36)
- diluted	$ 0.04	$ (0.36)

The dilutive factors are 1.8 million of the stock options described in Note 11. The diluted weighted average number of shares is calculated by assuming the proceeds that arise from the exercise of outstanding and in-the-money stock options are used to purchase common shares at the average market price during the period.

For 2014, 62,000 stock options were excluded from the calculation of dilutive shares as they were anti-dilutive. For 2013, all outstanding stock options were considered anti-dilutive as the Company incurred net losses.

13. 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 pricing information on an ongoing basis.
- 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 is determined with reference to published share prices and is therefore classified as a Level 1 financial instrument. The Company's investment in Chinook is carried at the December 31, 2014 fair value of $1.3 million.

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, 2014 is as follows:

	Carrying Amount as at December 31, 2014
Accounts receivable	$ 8,205
Fair value of commodity price contracts	12,920
Total	$ 21,125

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 bankers.

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 less than 0.1% of the Company's outstanding receivable balance is considered past due at December 31, 2014.

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 production loan, which is reviewed semi-annually, and which 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.

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.

As at December 31, 2014, Storm had the undernoted commodity price contracts in place. The fair market value of these contracts of $12,920,000 (December 31, 2013 – liability of $1,248,000) is included in current assets and the resulting unrealized mark-to-market gain of $14,168,000 (2013 – loss of $1,477,000) is recognized in the consolidated statement of income (loss). In January 2015 the Company terminated all of the crude oil contracts listed below in exchange for $5.1 million which will be included in the calculation of 2015 net income. In February 2015 the Company added an additional fixed contract for 4,000 GJ/day of natural gas at an AECO price of $2.85 per GJ for the period from April 1, 2015 to September 30, 2015.

		WTI Crude Oil		AECO Natural Gas
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q1 – 2015	600 Bbls/day	$101.06	2,000 GJ/day	$3.62
Q2 – 2015	600 Bbls/day	$ 98.34	21,667 GJ/day	$3.33
Q3 – 2015	400 Bbls/day	$ 94.61	30,000 GJ/day	$3.33
Q4 – 2015			30,000 GJ/day	$3.47
Collars		Average Range (Cdn$/Bbl)		Average Range (Cdn$/GJ)
Q1 – 2015			28,000 GJ/day	$3.62 - $4.41

During 2014, the Company realized losses from commodity price contracts in place in the amount of $3,198,000 (2013 – loss of $36,000).

All crude oil contracts are based on a WTI price in US$ per barrel which is then converted to Cdn$ using the foreign exchange rate when the contract is executed. All natural gas contracts are based on the AECO monthly index price.

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 changes 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 have no material direct effect on the Company's results; nevertheless, there is indirect linkage and variation in the Canadian-US dollar exchange rate will affect Canadian dollar prices for the Company's production. In addition, costs of imported materials used in the Company's operations will be affected by the Canadian-US dollar exchange rate.

Sensitivities

Using the Company's actual production volumes, royalty rates and debt levels for the year ended December 31, 2014, the estimated after-tax effect that changes in certain factors would have on net income and income per share is set out below:

		2014
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI	$ 470,000	$ -
$0.10/Mcf change in the price of natural gas	$ 1,100,000	$ 0.01
1% change in the interest rate	$ 270,000	$ -

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; 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 considers that a project requires too much capital or where the project affects the Company's investment risk profile.

14. 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 production expansion. 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, 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. Increased cash flow enables the Company to expand bank or other debt financing, an additional source of investment capital.

15. 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, 2014	Year Ended December 31, 2013
Salaries and short-term benefits	$ 1,340	$ 1,126
Share-based compensation	877	341
	$ 2,217	$ 1,467

16. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2014	Year Ended December 31, 2013
Accounts receivable	$ (2,020)	$ 2,631
Prepaids and deposits	112	(202)
Accounts payable and accrued liabilities	15,316	(502)
Change in non-cash working capital	$ 13,408	$ 1,927
Relating to:		
Operating activities	$ 2,917	$ 2,333
Investing activities	10,491	(406)
	$ 13,408	$ 1,927
Interest paid during the year	$ 1,153	$ 1,189
Income taxes paid during the year	$ -	$ -

17. COMMITMENTS

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

	2015	2016	2017	2018	2019
Office lease	$ 928	$ 940	$ 940	$ 705	-
Gas transportation and processing commitments	11,221	8,631	8,216	1,237	-
Total	$ 12,149	$ 9,571	$ 9,156	$ 1,942	-

In 2014 the Company made office lease payments of approximately $912,000 (2013 - $643,000) 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

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

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
Bank of Montreal
Royal Bank of Canada
Calgary, Alberta

Executive Offices

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

Abbreviations

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
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 dollar
WTI	West Texas Intermediate

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

www.stormresourcesltd.com