STORM RESOURCES

Q3 2014 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
FINANCIAL				
Revenue from product sales(1)	24,902	13,177	67,410	34,198
Funds from operations(2)	11,784	6,144	31,520	14,448
Per share - basic ($)	0.11	0.08	0.29	0.20
Per share - diluted ($)	0.11	0.08	0.29	0.20
Per Boe ($)	17.88	17.56	19.55	16.25
Net income (loss)	5,473	(1,429)	12,277	(1,029)
Per share - basic ($)	0.05	(0.02)	0.11	(0.01)
Per share - diluted ($)	0.05	(0.02)	0.11	(0.01)
Operations capital expenditures	30,426	23,717	86,385	60,559
Acquisitions and dispositions	-	-	88,075	(19,495)
Debt including working capital deficiency	56,157	40,968	56,157	40,968
Weighted average common shares, during period (000s)				
Basic	110,954	77,383	107,116	70,492
Diluted	112,526	77,383	108,828	70,492
Common shares (000s), end of period				
Basic	111,295	77,383	111,295	77,383
Fully diluted	115,341	81,279	115,341	81,279
OPERATIONS				
Oil equivalent (6:1)				
Barrels of oil equivalent per day	7,160	3,800	5,904	3,255
Average selling price (Cdn$ per Boe)(1)	37.80	37.69	41.82	38.49
Hedging loss (Cdn$ per Boe)	(1.17)	(0.24)	(2.29)	(0.09)
Royalties (Cdn$ per Boe)	(5.99)	(5.62)	(6.02)	(5.49)
Production (Cdn$ per Boe)	(9.53)	(10.36)	(9.87)	(11.41)
Transportation (Cdn$ per Boe)	(1.69)	(1.32)	(1.74)	(1.34)
General and administrative (Cdn$ per Boe)	(0.98)	(1.65)	(1.69)	(2.85)
Interest (Cdn$ per Boe)	(0.56)	(0.94)	(0.66)	(1.06)
Funds from operations netback (Cdn$ per Boe)	17.88	17.56	19.55	16.25
Gas Production				
Thousand cubic feet per day	33,674	16,458	27,667	13,803
Average selling price (Cdn$ per Mcf)	4.48	3.12	5.02	3.51
NGL production				
Barrels per day	1,154	600	882	450
Average selling price (Cdn$ per barrel)	73.09	73.98	78.33	70.40
Oil Production				
Barrels per day	394	458	412	504
Average selling price (Cdn$ per barrel)(1)	90.31	103.70	94.44	89.65
Wells drilled				
Gross	3.0	5.0	15.0	8.0
Net	3.0	5.0	15.0	7.6

(1) Excludes hedging gains and losses.

(2) Funds from operations and funds from operations per share are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 10 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 20 of the attached MD&A.

President's Message

THIRD QUARTER 2014 HIGHLIGHTS

- Production was 7,160 Boe per day (22% oil plus NGL), an increase of 88% from the same period last year and 31% from the previous quarter. On a per-share basis, the year-over-year increase was 31% using common shares outstanding at the end of each period. The increase was the result of growth at the Umbach property where third quarter production was 5,823 Boe per day which is 168% higher than a year ago and 46% higher than the previous quarter.

- NGL production was 1,154 barrels per day, a year-over-year increase of 554 Boe per day, or 92%. Increased NGL production was the result of production growth from the liquids-rich Montney formation at Umbach where recovery was 39 barrels per Mmcf sales in the third quarter. With 62% of the NGL mix being condensate plus pentanes, the NGL price of $73.09 per barrel was 75% of the average Edmonton Par light oil price.

- Activity was focused on Storm's 100% working interest lands at Umbach South where three Montney horizontal wells (3.0 net) were drilled, three horizontal wells (2.6 net) were completed, and the new field compression facility was started up ahead of schedule on August 19th.

- To date in 2014, seven horizontal wells (6.6 net) have started producing at Umbach which has resulted in corporate production increasing from 5,068 Boe per day in the first quarter to more than 10,500 Boe per day in October. The new facility at Umbach is full with throughput averaging 25 Mmcf per day since mid-September and there is an inventory of four completed horizontal wells (4.0 net) that will commence production as facility capacity becomes available plus five standing horizontal wells (5.0 net) that are awaiting completion.

- At Umbach, the five Montney horizontal wells that started production in 2014 with enough history have averaged 5.2 Mmcf per day gross raw gas (950 Boe per day sales) over the first 90 calendar days, a 50% improvement from the average 2013 horizontal well. Notably, over the first 180 calendar days, the first of the 2014 horizontal wells with enough history has averaged 4.9 Mmcf per day (900 Boe per day sales), a 70% improvement from the average 2013 horizontal well.

- The corporate field operating netback, excluding hedging gains or losses, was $20.59 per Boe, an increase of $0.20 per Boe from the previous year. The year-over-year improvement is mainly due to an 8% decrease in operating costs which were $9.53 per Boe.

- Funds from operations totaled $11.8 million or $0.11 per basic share, a year-over-year increase of 38% on a per-share basis. The funds from operations netback was $17.88 per Boe and was reduced by a hedging loss of $1.17 per Boe. Controllable cash costs (operating, transportation, cash G&A, interest expense) were $12.76 per Boe, a year-over-year decrease of 11%, or $1.51 per Boe.

- Net income was $5.5 million or $0.05 per share, a significant improvement when compared to the loss of $0.02 per share in the previous year.

- Capital investment was $30.4 million with major expenditures being $17.5 million for facilities and pipelines plus $11.5 million for drilling and completions.

- Debt plus working capital deficiency, net of investments, totaled $56.1 million at the end of the quarter which is 1.2 times annualized third quarter cash flow. In November 2014, Storm's banking syndicate increased the revolving bank facility to $130.0 million.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 141 net sections (167 gross sections), or 100,000 net acres. To date, the focus has been on exploiting the upper and middle Montney intervals. There are three project areas:

- Umbach South with 88 net sections at a 100% working interest where third quarter production was 4,761 Boe per day;

- Umbach North with 33 net sections of jointly owned lands (59 gross sections with Storm's working interest being 60% on most of the lands) where third quarter production was 1,061 Boe per day;

- Nig with 20 net sections at a 100% working interest.

Third quarter production from Umbach was 5,823 net Boe per day (19% NGL) with NGL production of 1,099 barrels per day representing a recovery of 39 barrels per Mmcf sales (62% higher priced condensate plus pentanes). Revenue after deducting transportation costs was $34.34 per Boe ($4.34 per Mcf sales and $69.49 per barrel of NGL), royalties were $5.45 per Boe, operating costs were $7.81 per Boe and the operating netback was $21.08 per Boe.

Activity in the third quarter included drilling three Montney horizontal wells (3.0 net), completing three Montney horizontal wells (2.6 net), and commissioning the second field compression facility at Umbach South. To date in 2014, 14 Montney horizontal wells (14.0 net) have been drilled and 11 horizontal wells (10.6 net) have been completed which includes two wells (1.6 net) drilled in 2012 and 2013. Seven (6.6 net) of the completed horizontal wells are producing. There remains an inventory of nine horizontal wells (9.0 net) that have not started production which includes six completed horizontal wells and three standing horizontal wells awaiting completion.

At Umbach South, the first field compression facility is full with throughput averaging 18 Mmcf per day of gross raw gas. The second field compression facility was started up ahead of schedule on August 19, 2014 with the estimated final cost being $15.1 million (8% higher than earlier guidance). Since mid-September, the new facility has been full with throughput averaging 25 Mmcf per day gross raw gas. With nine horizontal wells not yet producing because both facilities are full, expansion of the second facility to 48 Mmcf per day is being moved forward into late March 2015 at an estimated cost of $13.0 million ($3.5 million to purchase equipment in 2014 and the remaining $9.5 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 $4.9 million.

Given the improvement in horizontal well performance and existing facility capacity constraints, a third field compression facility with initial capacity of 35 Mmcf per day will be constructed in 2015 with start-up planned for October 2015. Cost of the third facility is estimated to be $24.0 million and it will be expandable to 70 Mmcf per day for an additional investment of $7.0 million.

Comparing calendar day rates over the first 90 days, the five 2014 Montney horizontal wells with enough history are 50% 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 30 Cal Day Gross Raw Mmcf Per Day	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	**2.7 Mmcf/d** 495 Boe/d sales 4 hz's	**2.0 Mmcf/d** 375 Boe/d sales 4 hz's	**1.5 Mmcf/d** 275 Boe/d sales 4 hz's	**1.3 Mmcf/d** 240 Boe/d sales 4 hz's
2012 hz's (3 wells)	14	**3.0 Mmcf/d** 550 Boe/d sales 3 hz's	**1.6 Mmcf/d** 295 Boe/d sales 3 hz's	**1.3 Mmcf/d** 240 Boe/d sales 3 hz's	**1.5 Mmcf/d** 275 Boe/d sales 3 hz's
2013 hz's (6 wells)	16 - 18	**4.0 Mmcf/d** 735 Boe/d sales 6 hz's	**3.5 Mmcf/d** 645 Boe/d sales 6 hz's	**2.9 Mmcf/d** 530 Boe/d sales 6 hz's	**2.2 Mmcf/d** 405 Boe/d sales 6 hz's
2014 hz's (7 wells)	16 - 18	**4.8 Mmcf/d** 880 Boe/d sales 7 hz's	**5.2 Mmcf/d** 950 Boe/d sales 5 hz's	**4.9 Mmcf/d** 900 Boe/d sales 1 hz	
Sales volume is calculated using 8% shrinkage from raw gas to sales and 33 barrels of NGL per Mmcf sales.					

Based on the performance of the 2013 and 2014 horizontal wells, Storm management is now using a 5.0 Bcf raw gas type curve for internal budgeting purposes (the previous 4.4 Bcf raw gas type curve was based on performance of the 2013 horizontal wells). Using a 5.0 Bcf raw gas type curve, the first year average rate is 2.9 Mmcf per day gross raw gas or 530 Boe per day sales (8% shrinkage from raw gas to sales and 33 barrels of NGL per Mmcf sales). Based on a cost of $4.9 million to drill, complete, and tie in a horizontal well, the payout is approximately 18 months assuming a flat natural gas price of $3.25 per GJ over the life of a well (see presentation on website for further details). To date in 2014, the cost to drill a horizontal well has averaged $2.2 million with the completion cost averaging $2.3 million. Drilling times have averaged approximately 14 days. Tie-in costs have averaged $0.4 million per horizontal well which doesn't include the cost of longer gathering pipelines to connect multi-well pads to field compression facilities.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 123 sections in the HRB (81,000 net acres) which is prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Third quarter production averaged 318 Boe per day (100% natural gas) at an operating netback of $7.39 per Boe with revenue of $21.67 per Boe, an operating cost of $11.06 per Boe and a royalty of $3.22 per Boe. Production is from one horizontal well with 12 fracture stimulations which currently produces 2.4 Mmcf per day gross raw gas with cumulative production of 4.4 Bcf gross raw gas since start-up in March 2011.

A resource evaluation completed by InSite Petroleum Consultants Ltd., effective December 31, 2011, estimates that the best estimate of DPIIP in the core producing area is 3.1 Tcf gross raw gas with the best estimate of contingent resources being 616 Bcf. The evaluated area includes 30 sections at a 100% working interest and represents 24% of Storm's total land holdings in the HRB. Commerciality has been proven across the core producing area with a horizontal well that has been producing for 41 months plus two vertical wells that were completed and tested with final test rates of 900 Mcf per day over the final 24 hours of each flow test.

Grande Prairie Area, Northwest Alberta and Northeast British Columbia

Production in the third quarter was 1,019 Boe per day (44% oil plus NGL), a year-over-year decline of 22%. The operating netback was $13.71 per Boe with revenue of $42.56 per Boe, an operating cost of $18.18 per Boe and a royalty of $9.90 per Boe. Equipment failures on six wells plus outages at third party facilities reduced production by approximately 170 Boe per day in the quarter and increased the operating cost by $3.70 per Boe. Production in October was approximately 1,200 Boe per day based on field estimates. Cash flow from this area continues to be re-invested to grow production at Umbach.

HEDGING UPDATE

Current commodity price hedges for the fourth quarter of 2014 include:

- 12,100 Mcf per day (14,500 GJ per day) of natural gas with an average floor price of approximately $4.07 per Mcf and an average ceiling price of $4.28 per Mcf (AECO monthly index $3.39 per GJ for the floor and $3.57 per GJ for the ceiling);

- 450 barrels per day of oil with an average floor price of WTI Cdn$102.43 per barrel and an average ceiling price of WTI Cdn$104.83 per barrel.

For January to September of 2015, commodity price hedges include:

- 18,000 Mcf per day (21,700 GJ per day) of natural gas with an average floor price of approximately $4.18 per Mcf and an average ceiling price of $4.61 per Mcf (AECO monthly index $3.48 per GJ for floor and $3.84 per GJ for ceiling);

- 533 barrels per day of oil with a price of WTI Cdn$98.43 per barrel.

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; production growth is not hedged.

OUTLOOK

Production in October was more than 10,500 Boe per day based on field estimates, and fourth quarter production is forecast to be approximately 10,500 Boe per day. Corporate production is expected to increase to approximately 13,500 Boe per day in April 2015 after the new field compression facility at Umbach is expanded to 48 Mmcf per day.

Updated guidance for 2014 is provided below. Forecast fourth quarter production is expected to be 10,500 Boe per day which is higher than previous guidance and represents year-over-year growth of 70% on a per-share basis. Operations capital expenditures will increase by $8.0 million with $3.5 million to purchase equipment to expand the second field compression facility at Umbach and $4.5 million to drill an additional two horizontal wells in December 2014. Total debt at the end of 2014 is forecast to be approximately $59.0 million which would be approximately 0.9 times annualized funds from operations in the fourth quarter of 2014 (assuming commodity prices in the fourth quarter of 2014 are AECO $3.50 per GJ and Edmonton Par Cdn$88.00 per barrel).

2014 Guidance	January 23, 2014 Original Guidance	May 14, 2014 Revised Guidance	November 13, 2014 Revised Guidance
AECO natural gas price	$3.35 per GJ	$4.25 per GJ	$4.30 per GJ
Edmonton Par light oil price	Cdn$89 per Bbl	Cdn$94 per Bbl	Cdn$97 per Bbl
Estimated average operating costs	$8.00 - $9.00 per Boe	$8.00 - $9.00 per Boe	$9.00 - $9.50 per Boe
Estimated average royalty rate (on production revenue before hedging)	14% - 15%	15% - 16%	15%
Estimated operations capital (excluding acquisitions & dispositions)	$78.0 million	$97.0 million	$105.0 million
Estimated acquisitions	$88.0 million	$88.0 million	$88.0 million
Estimated cash G&A net of recoveries	$4.0 million	$4.0 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)
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)
Umbach horizontal wells drilled	10 gross (10.0 net)	14 gross (14.0 net)	16 gross (16.0 net)
Umbach horizontal wells completed & tied in	9 gross (9.0 net)	13 gross (12.6 net)	13 gross (12.6 net)

Guidance for 2015 includes operations capital expenditures of $110.0 million with forecast fourth quarter production averaging 14,000 to 14,500 Boe per day (year-over-year growth of 35% on a per-share basis). Forecast annual production of 11,500 to 12,700 Boe per day assumes Umbach South is shut in for approximately 3 weeks during June 2015 for a scheduled maintenance turnaround at the McMahon Gas Plant (reduces production in the second quarter of 2015 to approximately 10,400 Boe per day). At Umbach South, $41.0 million will be invested to further expand infrastructure including $2.5 million for pipelines, $9.5 million to expand the second field compression facility, $4.9 million for a condensate stabilizer plus other equipment at the second field compression facility, and $24.0 million to construct a third field compression facility. Total debt is forecast to be $95.0 to $100.0 million at the end of 2015 which would be approximately 1.2 times annualized funds from operations in the fourth quarter of 2015 (assuming commodity prices in 2015 average AECO $3.25 per GJ and Edmonton Par Cdn$83.00 per barrel).

2015 Guidance

AECO natural gas price	$3.25 per GJ
Edmonton Par light oil price	Cdn$83 per Bbl
Estimated average operating costs	$7.50 - $8.00 per Boe
Estimated average royalty rate (on production revenue before hedging)	12% - 14%
Estimated operations capital (excluding acquisitions & dispositions)	$110.0 million
Estimated acquisitions	$0.0 million
Estimated cash G&A net of recoveries	$5.3 million
Forecast fourth quarter production	14,000 – 14,500 Boe/d (18% oil + NGL)
Forecast annual production	11,500 – 12,700 Boe/d (19% oil + NGL)
Umbach horizontal wells drilled	9 gross (9.0 net)
Umbach horizontal wells completed & tied in	14 gross (14.0 net)

At Umbach Storm has now drilled 29 horizontal wells (25.4 net) and 16.4 net horizontal wells are on production. The existing field compression facilities are full and there are six completed Montney horizontal wells (6.0 net) which will begin producing as facility capacity becomes available. In addition, three standing Montney horizontal wells (3.0 net) are awaiting completion. With the productivity of horizontal wells continuing to improve, and with the existing facilities forecast to remain full throughout 2015 even after expanding the second facility, the decision was made to add a third, larger field compression facility with initial capacity of 35 Mmcf per day. This results in field compression capacity increasing to 101 Mmcf per day at the end of 2015 and ensures that there will be enough capacity if horizontal well productivity continues to exceed the 5.0 Bcf raw gas type curve used for internal budgeting purposes. The large increase in field compression capacity will also allow for additional Montney horizontal wells to be drilled and completed in 2015 if commodity prices and results are supportive of doing so.

Storm has accumulated a large, higher quality land position at Umbach and approximately one third (47.6 net sections) has been delineated by the 25.4 net horizontal wells that have been drilled to date in the Montney formation. Assuming four horizontal wells per section, there is an inventory of 165.0 net horizontal wells that remain to be drilled. The remaining two thirds of Storm's lands (94.0 net sections) have not yet been tested with horizontal wells, but appear to be highly prospective given results from horizontal wells drilled by other operators on offsetting acreage.

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

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 13, 2014

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 November 13, 2014 for the three and nine months ended September 30, 2014.

Management's Discussion and 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 and nine months ended September 30, 2014. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2014, (ii) the Company's audited consolidated financial statements for the years ended December 31, 2013 and 2012, and (iii) the press release issued by the Company on November 13, 2014, 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 November 13, 2014.

LIMITATIONS

Basis of Presentation – Financial data presented below have largely been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 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 years ended December 31, 2013 and 2012. 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, 2013 and for the year then ended. These changes to accounting policies have no effect on financial statements for the three and nine month periods ended September 30, 2014 or the inter-period comparability of financial information.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three and nine month periods ended September 30, 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, 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;
- future non-GAAP funds from operations and future cash flows;
- 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 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” and related terms are forward-looking statements, as they involve the implied assessment, 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"; "Transportation Costs"; "Field Netbacks"; "General and Administrative Costs"; "Share-Based Compensation"; "Depletion and Depreciation"; "Exploration and Evaluation Costs"; "Accretion"; "Interest"; "Gain on Disposal of Investments"; "Gain (Loss) on Disposal of Oil and Gas Properties"; "Gain (Loss) on Commodity Price Contracts"; "Income Taxes"; "Net Income"; "Other Comprehensive Income (Loss)"; "Non-GAAP Funds from Operations and Funds from Operations Per Share"; "Cash Flows from Operating Activities"; "Corporate Netbacks"; "Financial Resources and Liquidity"; "Investments"; "Capital Expenditures"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Shareholders' Equity"; "Contractual Obligations"; industry conditions including commodity prices, facility and pipeline capacity constraints and access to market for production, volatility of commodity prices, currency fluctuations, imprecision of estimates of reserves and resources and related costs including royalties, production costs and future development costs, environmental risks, competition from other industry participants, the lack 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. All of these caveats should be considered in the context of current economic conditions, in particular volatile pricing for natural gas, the attitude of lenders and investors towards corporations with a natural gas focus, 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", "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".

OPERATIONAL AND FINANCIAL RESULTS

Overview

In the third quarter of 2014 Storm saw marked production growth as a new compressor station was commissioned at Umbach South in mid-August. Additional compression capacity enabled the Company to turn on two 100% working interest horizontal wells in August followed by another two similar wells in September. In late July at Umbach North, Storm completed and tied in one 60% working interest horizontal well, which had been drilled in 2012 and left standing until there was capacity at the facility. In addition, at Umbach South, three more 100% working interest horizontal wells were drilled and the completion of two 100% working interest wells began towards the end of the quarter. The new compressor station has been operating at 25 Mmcf per day almost since commissioning. Storm currently has six 100% working interest horizontal wells that are completed and will commence production when facility capacity becomes available. In addition, three 100% working interest horizontal wells have been drilled that await completion. Profitability of natural gas production at Umbach is enhanced by associated NGL, currently approximating 39 barrels per Mmcf, of which 62% is high-value condensate and pentane, with the remaining amount being approximately equal volumes of butane and propane. The Company holds a total of 141 net sections of land at Umbach.

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 the end of the third quarter, Storm had an interest in 123 net sections in this area. In the Grande Prairie area of northwest Alberta, production in the quarter was 1,019 Boe per day declining from 1,136 Boe per day in the second quarter of 2014. Production at Grande Prairie in the quarter was affected by downtime required for maintenance and workovers. No material capital was directed to either HRB or Grande Prairie in the quarter to September 30, 2014.

Average daily production in the third quarter of 2014 jumped 88% to 7,160 Boe per day from 3,800 Boe per day in the third quarter of 2013 and by 31% from 5,462 Boe per day in the immediately preceding quarter. Net production increases for the quarter came entirely from Umbach.

During the third quarter, Storm's production mix was 78% natural gas, 16% NGL and 6% crude oil. Natural gas production increased by 105% compared to the third quarter of 2013 as production at Umbach averaged 28.3 Mmcf per day for the quarter compared to 9.9 Mmcf per day for the same quarter in 2013 and to 19.7 Mmcf per day in the second quarter of 2014. Crude oil production dropped by 14% in the third quarter of 2014 relative to the third quarter of 2013 due to downtime. NGL production increased 92%, from 600 Bbls per day in the third quarter of 2013 to 1,154 Bbls per day in the third quarter of 2014, as a result of increased liquids volumes associated with growing natural gas production at Umbach. Prices for natural gas in the third quarter increased from 2013, with oil and NGL prices declining, resulting in the realized price per Boe being largely flat year over year at $37.80. However, when compared to the second quarter of 2014, the realized price per Boe fell by 13%. Further, a hedging loss of $1.17 per Boe was realized in the third quarter of 2014. Natural gas prices continued to soften early in the fourth quarter but may now be strengthening in the face of the winter heating season.

In the third quarter, Storm spent $30.4 million on field activities including $11.5 million on drilling and completions, $9.9 million on the new Umbach facility and $7.6 million on equipping and gathering.

Increased production at Umbach and lower costs resulted in an increase in non-GAAP funds from operations to $11.8 million, up from $6.1 million in the third quarter of 2013 and from $11.1 million in the second quarter of 2014.

In November 2014 Storm's banking syndicate committed to increase the bank facility from $90.0 million to $130.0 million in recognition of production growth at Umbach.

Expansion of Umbach infrastructure will continue in 2015 with expansion of the field compression facility at Umbach South to 48 Mmcf per day by the end of the first quarter, and with plans to construct a third field compression facility with an initial capacity of 35 Mmcf per day, expandable to 70 Mmcf per day, in the second half of 2015.

Production and Revenue

Production by Area

The Company reported production from the following areas:

			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

			Three Months to September 30, 2013	
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	9,895	521	-	2,170
Horn River Basin – NE BC	2,013	-	-	335
Grande Prairie Area – AB	4,550	79	458	1,295
Total	16,458	600	458	3,800

				Nine 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	21,860	818	-	4,461
Horn River Basin – NE BC	2,088	-	-	348
Grande Prairie Area – AB	3,719	64	412	1,095
Total	27,667	882	412	5,904

				Nine Months to September 30, 2013
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	6,858	362	-	1,505
Horn River Basin – NE BC	2,075	-	-	346
Grande Prairie Area - AB	4,870	88	504	1,404
Total	13,803	450	504	3,255

Production increases for natural gas and NGL came from Umbach where the Company began production from five wells (4.6 net) during the quarter. Four 100% working interest wells began production in August and September with one 60% working interest well at Umbach North beginning production in July. Crude oil production declines from the prior year increased as a result of wells being shut in for maintenance and workovers. Production to date in the fourth quarter is currently averaging more than 10,500 Boe per day based on field estimates.

Daily production per million shares outstanding at the end of each period averaged 64 Boe per day for the third quarter of 2014, compared to 49 Boe per day for the third quarter of 2013 and 50 Boe per day for the immediately preceding quarter.

HRB produces dry gas, while Umbach produces gas and associated NGL. Production in Alberta for the third quarter approximated 39% light oil, with an average API of 37 degrees, 56% natural gas and 5% NGL.

Average Daily Production

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Natural gas (Mcf/d)	33,674	16,458	27,667	13,803
Natural gas liquids (Bbls/d)	1,154	600	882	450
Crude oil (Bbls/d)	394	458	412	504
Total (Boe/d)	7,160	3,800	5,904	3,255

Production Profile and Per-Unit Prices(1)

	Three Months to Sept. 30, 2014		Three Months to Sept. 30, 2013		Nine Months to Sept. 30, 2014		Nine Months to Sept. 30, 2013	
	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas - Mcf	78%	$ 4.48	72%	$ 3.12	78%	$ 5.02	71%	$ 3.51
Natural gas liquids - Bbl	16%	73.09	16%	73.98	15%	78.33	14%	70.40
Crude oil - Bbl	6%	90.31	12%	103.70	7%	94.44	15%	89.65
Per Boe	100%	$ 37.80	100%	$ 37.69	100%	$ 41.82	100%	$ 38.49

(1) Before realized hedging losses of $1.17 and $2.29 per Boe for the three and nine months ended September 30, 2014 respectively. In 2013 the hedging losses were $0.24 per Boe for the three month period and $0.09 per Boe for the nine month period.

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 index in British Columbia and at the AECO index in Alberta. In the third quarter, approximately 35% of natural gas sales were priced at the AECO monthly index price, 4% at the AECO daily index price and 61% was sold at Station 2 daily index price. Equivalent percentages for the third quarter of 2013 were 28% at the AECO monthly index price and 72% at the Station 2 daily index price. Average index prices per GJ for each quarter are as follows:

(Cdn$/GJ)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
AECO Monthly Index	$ 4.00	$ 2.67	$ 4.31	$ 3.00
AECO Daily Index	$ 3.81	$ 2.31	$ 4.56	$ 2.89
Station 2	$ 3.54	$ 2.52	$ 4.23	$ 2.88

A portion of Storm's natural gas is sold at the AECO monthly index price rather than the daily index price to ensure alignment with the Company's natural gas hedges which are priced in accordance with the monthly index.

Storm's realized price for the third quarter was $4.48 per Mcf, with the price higher than index prices (after conversion from GJ to Mcf) as a result of sales gas from Umbach and Grande Prairie having a higher heat content.

The year-over-year decrease in Storm's realized NGL sales price of $0.89 per barrel followed the decrease in the Edmonton Par crude oil price offset by the increased proportion of higher priced condensate and pentanes in Storm's total NGL mix. 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 third quarter, WTI averaged US$97.17 per barrel and Edmonton Par was Cdn$97.16 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton Par of Cdn$8.67 per barrel, compared to Cdn$4.73 per barrel in the third quarter of 2013. The third quarter differential between Edmonton Par and WTI was generally consistent with the nine month 2014 average differential which was Cdn$8.14 per barrel. Due to quality and gravity differentials, Storm's average crude oil sales price for the third quarter of 2014, prior to the inclusion of hedging losses, was $6.85 per barrel lower than the Edmonton Par reference price for light sweet crude oil.

Revenue from Product Sales(1)

(000s)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Natural gas (Mcf/d)	$ 13,869	$ 4,729	$ 37,946	$ 13,212
Natural gas liquids (Bbls/d)	7,758	4,082	18,852	8,642
Crude oil (Bbls/d)	3,275	4,366	10,612	12,344
Total	$ 24,902	$ 13,177	$ 67,410	$ 34,198

(1) Excludes hedging gains and losses.

Revenue from product sales for the third quarter of 2014 increased by 89% when compared to the third quarter of 2013 corresponding to a production increase of 88%.

The nine month year-over-year revenue increase of 97% is due to Boe volume growth of 81% and an increase in per-Boe pricing of 9%.

Hedging

The Company has in place the following hedging arrangements, including arrangements entered into subsequent to September 30, 2014:

	WTI Crude Oil		AECO Natural Gas	
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q4 – 2014	300 Bbls/day	$103.65	10,500 GJ/day	$3.51
Q1 – 2015	600 Bbls/day	$101.06	2,000 GJ/day	$3.62
Q2 – 2015	600 Bbls/day	$ 98.34	15,000 GJ/day	$3.33
Q3 – 2015	400 Bbls/day	$ 94.61	20,000 GJ/day	$3.36
Collars		Average Range (Cdn$/Bbl)		Average Range (Cdn$/GJ)
Q4 – 2014	150 Bbls/day	$100.00 - $107.20	4,000 GJ/day	$3.12 - $3.75
Q1 – 2015			28,000 GJ/day	$3.62 - $4.40

Realized hedging losses amounted to $0.8 million for the quarter ended September 30, 2014 and $3.7 million for the nine month period. Prior year amounts were insignificant for both the three and nine month periods. Unrealized gains for the three months to September 30, 2014 amounted to $2.0 million with unrealized gains for the nine month period amounting to $0.6 million. Details by commodity of unrealized gains and losses are provided on page 19. The fair market value of hedges in place at September 30, 2014 was negative $0.6 million.

For natural gas volumes that have been hedged at AECO monthly index pricing, an equal volume of produced natural gas is sold at the same index. For the remainder of 2014, approximately 11,800 Mcf per day (14,500 GJ per day) will likely be sold at AECO monthly index pricing with the remaining volumes of natural gas being sold at the daily spot price, either AECO or Station 2.

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. 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 expenditure programs necessary to build out a potentially decades-long project have to be insulated from the effects of near-term price movements.

Royalties

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 3,943	$ 1,966	$ 9,696	$ 4,874
Percentage of revenue from product sales	15.8%	14.9%	14.4%	14.3%
Per Boe	$ 5.99	$ 5.62	$ 6.02	$ 5.49

Total royalties in the third quarter of 2014 increased by 100% when compared to the same quarter of 2013 and increased by 99% when comparing the first nine months of 2014 to the first nine months of 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 during 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 an infrastructure royalty credit at Umbach which reduced second quarter 2014 royalties by $1.6 million. Royalties as a percentage of revenue increased from 14.9% to 15.8% year over year for the third quarter and were largely the same for the comparative nine month periods. The royalty rate for the second quarter of 2013 was 10.7%, or $4.64 per Boe, as a result of a credit received under British Columbia's Infrastructure Royalty Credit Program.

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 $4.7 million net 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 cannot be forecasted; correspondingly, royalty rates reported in future quarters could vary considerably.

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 no longer benefits from royalty credits under this program.

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. Umbach wells generally did not meet the prior 1,900 metre depth threshold. 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 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 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, 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

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 6,279	$ 3,621	$ 15,917	$ 10,141
Percentage of revenue from product sales	25.2%	27.5%	23.6%	29.7%
Per Boe	$ 9.53	$ 10.36	$ 9.87	$ 11.41

Total production costs for the quarter increased by 73% when compared to the third quarter of 2013 and by 34% when compared to the second quarter of 2014. These increases in production costs largely correspond to increased production at Umbach.

For the third quarter, production costs per Mcf of natural gas averaged $1.72 and production costs per barrel of crude oil averaged $25.91, with total production costs averaging $9.53 per Boe. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for the third quarter of 2013 were $2.03 per Mcf of natural gas and $12.84 per barrel for crude oil, with total production costs averaging $10.36 per Boe. The increase in production costs for crude oil was a result of workovers and repairs and maintenance in the Grande Prairie area. Per-Boe production costs for the second quarter of 2014 averaged $9.41. For the comparative nine month periods, per-Boe production costs averaged $9.87 in 2014 and $11.41 in 2013.

Although production costs for natural gas are trending downwards, production costs for crude oil for the quarter increased by 101% year over year and by 66% when compared to the second quarter of 2014. The cost increase resulted from maintenance and workovers on the Company's Alberta properties.

The decrease in per-Boe costs between the third quarter of 2014 and the third quarter of 2013 is attributable to growth at Umbach resulting in an increase in lower cost natural gas as a proportion of total corporate volumes, from 72% in the third quarter of 2013 to 78% in the third quarter of 2014, a trend expected to continue.

Transportation Costs

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 1,111	$ 460	$ 2,802	$ 1,192
Percentage of revenue from product sales	4.5%	3.5%	4.2%	3.5%
Per Boe	$ 1.69	$ 1.32	$ 1.74	$ 1.34

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 the third quarter of 2014 increased by 142% over the same quarter of 2013, and for the nine month periods to September 30, increased 135%, both consistent with increased production and the shift in commodity mix. Per-Boe transportation costs averaged $1.83 for the second quarter of 2014.

Year over year, there were increases in total transportation costs for all three commodities. Higher volumes of field condensate at Umbach resulted in increased NGL trucking charges.

Field Netbacks

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

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

Three Months to September 30, 2013	Crude Oil ($/Bbl)	Natural Gas Liquids ($/Bbl)	Natural Gas ($/Mcf)	Total ($/Boe)
Production revenue	$ 103.70	$ 73.98	$ 3.12	$ 37.69
Royalties	(26.09)	(15.17)	(0.02)	(5.62)
Production costs	(12.84)	-	(2.03)	(10.36)
Transportation costs	(3.36)	(1.33)	(0.16)	(1.32)
Field operating income per Boe before hedging	$ 61.41	$ 57.48	$ 0.91	$ 20.39
Realized hedging gains (losses)	(12.47)	-	0.29	(0.24)
Total operating income per Boe	$ 48.94	$ 57.48	$ 1.20	$ 20.15
Total operating income (000s)	$ 2,057	$ 3,170	$ 1,796	$ 7,046

Nine Months to September 30, 2014	Crude Oil ($/Bbl)	Natural Gas Liquids ($/Bbl)	Natural Gas ($/Mcf)	Total ($/Boe)
Production revenue	$ 94.44	$ 78.33	$ 5.02	$ 41.82
Royalties	(22.92)	(15.57)	(0.45)	(6.02)
Production costs	(21.37)	-	(1.79)	(9.87)
Transportation costs	(5.60)	(2.97)	(0.19)	(1.74)
Field operating income per Boe before hedging	$ 44.55	$ 59.79	$ 2.59	$ 24.19
Realized hedging gains (losses)	(7.81)	-	(0.37)	(2.29)
Total operating income per Boe	$ 36.74	$ 59.79	$ 2.22	$ 21.90
Total operating income (000s)	$ 4,130	$ 14,387	$ 16,793	$ 35,311

Nine Months to September 30, 2013	Crude Oil ($/Bbl)	Natural Gas Liquids ($/Bbl)	Natural Gas ($/Mcf)	Total ($/Boe)
Production revenue	$ 89.65	$ 70.40	$ 3.51	$ 38.49
Royalties	(20.14)	(15.38)	(0.06)	(5.49)
Production costs	(13.78)	-	(2.19)	(11.41)
Transportation costs	(3.82)	(0.66)	(0.16)	(1.34)
Field operating income per Boe before hedging	$ 51.91	$ 54.36	$ 1.10	$ 20.25
Realized hedging gains (losses)	(4.42)	-	0.14	(0.09)
Total operating income per Boe	$ 47.49	$ 54.36	$ 1.24	$ 20.16
Total operating income (000s)	$ 6,535	$ 6,674	$ 4,683	$ 17,915

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

Total field operating income for the third quarter of 2014 was 82% higher than the same quarter of 2013. Year over year, quarterly natural gas revenue increased by 193% in 2014 as a result of increased production at Umbach, while oil revenues decreased by 25% with both volumes and pricing falling. Measured per Boe, third quarter revenue and netback were largely the same.

For the third quarter year over year, increased royalty and transportation costs per Boe were offset by higher per-Boe revenues and lower production costs with a lower per-Boe netback resulting from higher realized hedging losses. Compared to the second quarter of 2014, field netback per Boe fell by 26%. Production revenue per Boe for the second quarter of 2014 was higher by 16%, royalties were lower by 22% and production and transportation costs were marginally higher.

Year-to-date netback per Boe prior to hedging adjustments was 19% higher than the previous year. Higher average prices were realized across the commodity stream along with lower production costs: these factors were offset in part by higher royalty and transportation costs.

Cash costs per Boe, comprising production costs, transportation, general and administrative costs and interest, amounted to $12.76 for the third quarter of 2014 compared to $14.27 for the equivalent quarter of 2013. The Company experienced significant year-over-year reductions per Boe in production, general and administrative and interest costs which more than offset increases in transportation costs. A similar drop to $13.96 from $16.66 is evident when comparing the nine month period in 2014 to 2013. Cash costs per Boe for the second quarter of 2014 averaged $13.73.

General and Administrative Costs

Total Costs	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period – before recoveries	$ 1,278	$ 1,058	$ 4,375	$ 3,606
Overhead recoveries	(634)	(482)	(1,646)	(1,077)
Charge for period – net of recoveries	$ 644	$ 576	$ 2,729	$ 2,529
Per Boe	$ 0.98	$ 1.65	$ 1.69	$ 2.85

Gross general and administrative costs for the third quarter of 2014 increased by 21% when compared to the third quarter of 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. The same observations apply to the comparable nine month periods.

On a per-Boe measure, net general and administrative costs fell by 41% compared to the third quarter of 2013 due to 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.

Share-Based Compensation

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 611	$ 241	$ 1,436	$ 664
Per Boe	$ 0.93	$ 0.69	$ 0.89	$ 0.75

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 153% in the third quarter of 2014 compared to the same quarter of 2013. The year-over-year increase in share-based compensation in both the three and nine month periods is attributable to the grant of 1,832,000 stock options primarily in the first quarter of 2014.

Depletion and Depreciation

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Depletion	$ 6,587	$ 4,639	$ 16,904	$ 12,178
Depreciation	1,021	408	2,468	1,045
Charge for period	$ 7,608	$ 5,047	$ 19,372	$ 13,223
Per Boe	$ 11.55	$ 14.42	$ 12.02	$ 14.88

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 the reporting period by proved plus probable reserves at the beginning of the period.

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

Higher production volumes resulted in the total charge for depletion and depreciation increasing year over year in the third quarter and year to date in 2014. The quarterly year-over-year per-Boe charge fell by 20%, as reserves continued to grow at Umbach, reflecting Storm's successful drilling program.

In addition, management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at September 30, 2014 and determined that no impairment adjustment was required.

Exploration and Evaluation Costs Expensed

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 7	$ 215	$ 275	$ 215
Per Boe	$ 0.01	$ 0.61	$ 0.17	$ 0.24

Exploration and evaluation costs expensed is a non-cash charge representing the cost of undeveloped lands which have expired.

Accretion

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 91	$ 54	$ 241	$ 167

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

Interest

(000's)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Charge for period	$ 370	$ 326	$ 1,062	$ 938
Percentage of revenue from product sales	1.0%	2.5%	1.6%	2.7%
Per Boe	$ 0.56	$ 0.94	$ 0.66	$ 1.06

Compared to the prior year, interest costs in 2014, for both the three and nine month periods, grew in comparison to 2013, 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. Expanded use of the Company's credit facility in future quarters will 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 third quarter of 2014.

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 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. Subsequent disposals have been minor.

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. Details of hedging positions completed during the reporting period and quarter-end valuation of contracts in place at the end of the reporting period and which relate to future periods are as follows:

	Three Months to Sept. 30, 2014		Three Months to Sept. 30, 2013		Nine Months to Sept. 30, 2014		Nine Months to Sept. 30, 2013	
Realized gain (loss)								
Crude oil	$(180)	$ (4.95)/Bbl	$(525)	$(12.47)/Bbl	$ (877)	$(7.81)/Bbl	$(609)	$ (4.42)/Bbl
Natural gas	(591)	$ (0.19)/Mcf	441	$ 0.29/Mcf	(2,807)	$(0.37)/Mcf	533	$ 0.14/Mcf
Total realized gain/(loss) - cash	$(771)	$ (1.17)/Boe	$ (84)	$ (0.24)/Boe	$(3,684)	$(2.29)/Boe	$ (76)	$ (0.09)/Boe

	Three Months to Sept. 30, 2014		Three Months to Sept. 30, 2013		Nine Months to Sept. 30, 2014		Nine Months to Sept. 30, 2013	
Unrealized gain (loss)								
Crude oil – change in fair value	$1,016	$28.02/Bbl	$ (36)	$ (0.86)/Bbl	$ 490	$ 4.36/Bbl	$(260)	$ (1.90)/Bbl
Natural gas – change in fair value	1,010	$ 0.33/Mcf	(278)	$ (0.18)/Mcf	151	$ 0.02/Mcf	47	$ 0.01/Mcf
Total unrealized gain (loss) – non-cash	$2,026	$ 3.08/Boe	$(314)	$ (0.90)/Boe	$ 641	$ 0.40/Boe	$(213)	$ (0.24)/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 September 30, 2014	Maximum Annual Deduction
Canadian oil and gas property expense	$ 69,000	10%
Canadian development expense	96,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	67,000	20 - 100%
Operating losses	130,000	100%
Other	5,000	20 - 100%
Total	$ 389,000	

Net Income (Loss)

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Net income (loss)	$ 5,473	$ (1,429)	$ 12,277	$ (1,029)
Per basic and diluted share	$ 0.05	$ (0.02)	$ 0.11	$ (0.01)

Other Comprehensive Income (Loss)

Other comprehensive income comprises net income (loss) for the period plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. 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)]	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Chinook Energy Inc.	Common Shares	1,000,000	$ (170)	$ 960	$ 890	$ -
Other comprehensive income (loss) for period			$ (170)	$ 960	$ 890	$ -

(1) Shares owned at September 30, 2014.

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

	Three Months to Sept. 30, 2014		Three Months to Sept. 30, 2013		Nine Months to Sept. 30, 2014		Nine Months to Sept. 30, 2013	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds from operations	$11,784	$0.11	$ 6,144	$0.08	$31,520	$0.29	$14,448	$0.20

Non-GAAP funds from operations for the third quarter of 2014 increased by 92% from the third quarter of 2013, and for the nine month period increased by 118% compared to the prior year. Compared to the immediately prior quarter, non-GAAP funds from operations for the quarter ended September 30, 2014 increased by 6%.

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 lending institutions to determine debt-to-cash-flow ratios and other measures of credit worthiness and thus determines interest rates on borrowings. The most directly comparable measure under GAAP is cash flows from operating activities, as set out below.

Cash Flows from Operating Activities

	Three Months to Sept. 30, 2014		Three Months to Sept. 30, 2013		Nine Months to Sept. 30, 2014		Nine Months to Sept. 30, 2013	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Non-GAAP funds from operations	$11,784	$0.11	$ 6,144	$0.08	$31,520	$0.29	$14,448	$0.20
Net change in non-cash working capital items	(1,081)	(0.01)	289	0.01	(662)	(0.01)	2,883	0.04
Cash from operating activities	$10,703	$0.10	$ 6,433	$0.09	$30,858	$0.28	$17,331	$0.24

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)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Revenue from product sales	37.80	37.69	41.82	38.49
Hedging loss	(1.17)	(0.24)	(2.29)	(0.09)
Royalties	(5.99)	(5.62)	(6.02)	(5.49)
Production	(9.53)	(10.36)	(9.87)	(11.41)
Transportation	(1.69)	(1.32)	(1.74)	(1.34)
General and administrative	(0.98)	(1.65)	(1.69)	(2.85)
Interest	(0.56)	(0.94)	(0.66)	(1.06)
Funds from operations netback	17.88	17.56	19.55	16.25
Share-based compensation	(0.93)	(0.69)	(0.89)	(0.75)
Depletion, depreciation and accretion	(11.69)	(14.57)	(12.17)	(15.07)
Exploration and evaluation costs expensed	(0.01)	(0.61)	(0.17)	(0.24)
Gain on disposal of investments	-	-	0.92	-
Unrealized revaluation loss on investments	-	(4.81)	-	(1.89)
Reduction of carrying amount of property and equipment	-	-	-	-
Gain (loss) on disposal of oil and gas properties	(0.03)	(0.06)	(0.03)	0.77
Unrealized gain (loss) on commodity price contracts	3.08	(0.90)	0.40	(0.24)
Net income (loss) per Boe	8.30	(4.08)	7.61	(1.17)

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.

Investments

The Company owns listed shares as set out below, which are valued at the closing price on the TSX at September 30, 2014. Proceeds from the possible future sale of this investment may be used to finance Storm's capital programs.

	Holding	Number of Shares	Exchange	Closing Price Sept. 30, 2014	Value at Sept. 30, 2014
Chinook Energy Inc.	Common Shares	1,000,000	TSX	$ 2.05	$ 2,050

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 third quarter of 2014.

Capital Expenditures

For the quarter to September 30, 2014, the Company spent $30.4 million, almost all at Umbach, including the drilling of three horizontal wells. Three horizontal wells (2.6 net) were completed in the quarter. In addition, a new compression facility became operational in mid-August 2014.

In the first nine months of 2014, the Company spent $86.4 million, mainly 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.

Through the first nine months of 2014, the Company drilled 14 gross (14.0 net) horizontal wells and one vertical delineation well, completed 11 wells and tied in seven wells at Umbach. Major field capital outlays year-to-date include $55.7 million on drilling and completions and $26.8 million on facilities, equipping and tie-ins, almost all in the Umbach area.

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Land and lease	$ 567	$ 738	$ 1,421	$ 15,081
Drilling	6,644	8,702	33,380	15,078
Completions	4,844	7,682	22,320	12,930
Facilities, equipping and gathering	17,479	6,108	26,835	10,921
Recompletions and workovers	867	472	2,369	1,895
Proceeds on disposition of oil and gas properties	-	-	-	(19,495)
Property and facility acquisitions	-	-	88,075	4,497
Property acquisition adjustments, seismic and administrative assets	25	15	60	157
Total capital expenditures	$ 30,426	$ 23,717	$ 174,460	$ 41,064

Capital expenditures in the reporting periods were allocated as follows:

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Exploration and evaluation	$ 245	$ 716	$ 80,585	$ 14,568
Property and equipment	30,181	23,001	93,875	26,496
Total – net of dispositions	$ 30,426	$ 23,717	$ 174,460	$ 41,064

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 September 30, 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 the periods ended September 30, 2014 reflect (i) additional liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of the inflation and discount rates and future costs and timing of incurrence of such costs, (iii) less the decommissioning obligations associated with dispositions of oil and gas properties, (iv) actual disposition costs incurred, (v) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.6%. Future costs to abandon and reclaim the Company's properties are based on an internal evaluation, supported by external information from industry sources.

Shareholders' Equity

Details of share issuances from inception to September 30, 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
Nine months ended Sept.30/14	Stock option exercises	1,683	$ 3.28	5,520
		23,812		98,295
Total		111,295	$ 3.19	$ 355,194

(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 the first nine months of 2014, stock options were exercised at $3.28 per optioned share and 1,683,000 common shares were issued for proceeds of $5,520,240.

Issued and outstanding common shares at September 30, 2014 was 111,295,312 and remains the same on November 13, 2014, the date of this MD&A.

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 no material obligations with a term longer than twelve months except for 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 office operating costs amount to $27,300.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 2014 appears below:

	2014			2013				2012
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production revenue ($000s)[1]	24,131	20,202	19,393	15,420	13,093	11,960	9,069	11,139
Non-GAAP funds from operations ($000s)[2]	11,784	11,076	8,660	7,501	6,144	5,077	3,227	5,016
Per share								
- basic ($)	0.11	0.10	0.09	0.09	0.08	0.07	0.05	0.08
- diluted ($)	0.11	0.10	0.08	0.09	0.08	0.07	0.05	0.08
Net income (loss) ($000s)	5,473	6,598	206	(25,174)	(1,429)	661	(261)	(2,320)
Per share								
- basic ($)	0.05	0.06	0.00	(0.34)	(0.02)	0.01	0.00	(0.04)
- diluted ($)	0.05	0.06	0.00	(0.34)	(0.02)	0.01	0.00	(0.04)
Net capital expenditures ($000s)	30,426	33,640	110,394	11,380	23,717	16,710	637	8,777
Average daily production - Boe	7,160	5,462	5,068	4,773	3,800	3,460	2,488	2,815
Net (debt)/working capital ($000s)[3]	(56,157)	(41,837)	(22,176)	(12,059)	(40,968)	(22,671)	(38,656)	(40,376)

(1) Includes hedging gains and losses.
(2) See Non-GAAP Measurements on page 10 of this MD&A.
(3) Includes investments.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the period ended September 30, 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 involving a high degree of measurement uncertainty. Variations between amounts estimated and actual results 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 as a result of the acquisitions. 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 companies or assets 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 operations and financial position.

Accounts Payable and Accrued Liabilities

At the end of each reporting period, the Company estimates the cost of goods and services provided during the reporting period when the cost has not been invoiced to the Company by the reporting date. The Company estimates and recognizes the cost of such unbilled goods and services using well established measurement procedures. Nonetheless, such procedures are subject to measurement uncertainty.

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 charged to 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.

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 initially estimated.

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.

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 so 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 a measurement 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. Information with respect to such risks is set out in Storm's Annual Information Form dated March 31, 2014 for the year ended December 31, 2013 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2013 under the heading "Risk Assessment".

FINANCIAL REPORTING UPDATE

There were no significant accounting policy developments during the first nine months of 2014.

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.

Condensed Interim Consolidated Financial Statements

Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	September 30, 2014	December 31, 2013
ASSETS		
Current		
Accounts receivable	$ 11,461	$ 6,185
Prepaids and deposits	731	1,017
Investments (Note 3)	2,050	3,480
	14,242	10,682
Exploration and evaluation (Note 4)	167,458	87,396
Property and equipment (Note 5)	234,271	152,472
	$ 415,971	$ 250,550
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 31,494	$ 12,114
Fair value of commodity price contracts (Note 12)	607	1,248
	32,101	13,362
Bank indebtedness (Note 6)	38,905	10,627
Decommissioning liability (Note 7)	16,024	8,689
	87,030	32,678
Shareholders' equity		
Share capital (Note 9)	351,048	252,837
Contributed surplus (Note 10)	2,660	2,969
Deficit	(25,657)	(37,934)
Accumulated other comprehensive income	890	-
	$ 328,941	$ 217,872
Commitments (Note 16)		
	$ 415,971	$ 250,550

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

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

(Canadian $000s except per-share amounts) (unaudited)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Revenue				
Revenue from product sales	$ 24,902	$ 13,177	$ 67,410	$ 34,198
Realized loss on commodity price contracts (Note 12)	(771)	(84)	(3,684)	(76)
Royalties	(3,943)	(1,966)	(9,696)	(4,874)
	$ 20,188	$ 11,127	$ 54,030	$ 29,248
Expenses				
Production	6,279	3,621	15,917	10,141
Transportation	1,111	460	2,802	1,192
General and administrative	644	576	2,729	2,529
Share-based compensation (Note 10)	611	241	1,436	664
Depletion and depreciation	7,608	5,047	19,372	13,223
Exploration and evaluation costs expensed (Note 4)	7	215	275	215
Accretion	91	54	241	167
	16,351	10,214	42,772	28,131
Income before the following:	3,837	913	11,258	1,117
Interest expense	(370)	(326)	(1,062)	(938)
Gain on disposal of investments (Note 3)	-	-	1,486	-
Unrealized revaluation loss on investments (Note 3)	-	(1,680)	-	(1,680)
Gain (loss) on disposal of oil and gas properties (Note 5)	(20)	(22)	(46)	685
Unrealized gain (loss) on commodity price contracts (Note 12)	2,026	(314)	641	(213)
Net income (loss) for the period	5,473	(1,429)	12,277	(1,029)
Other comprehensive income (loss)				
Reversal of prior period unrealized loss (gain) on investments (Note 3)	(170)	960	890	-
Other comprehensive income (loss)	(170)	960	890	-
Comprehensive income (loss) for the period	$ 5,303	$ (469)	$ 13,167	$ (1,029)
Net income (loss) per share (Note 11)				
- basic	$ 0.05	$ (0.02)	$ 0.11	$ (0.01)
- diluted	$ 0.05	$ (0.02)	$ 0.11	$ (0.01)

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Nine Months to September 30, 2014	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$252,837	$ 2,969	$ (37,934)	$ -	$217,872
Net income for the period	-	-	12,277	-	12,277
Issue of common shares (Note 9)	98,295	-	-	-	98,295
Share issue costs (Note 9)	(1,829)	-	-	-	(1,829)
Share-based compensation (Note 10)	-	1,436	-	-	1,436
Transfer of share-based compensation on options exercised (Note 10)	1,745	(1,745)	-	-	-
Reversal of prior period unrealized loss on investments (Note 3)	-	-	-	890	890
Balance, end of period	$351,048	$ 2,660	$ (25,657)	$ 890	$328,941

(Canadian $000s) (unaudited)				Nine Months to September 30, 2013	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Loss	Total Equity
Balance, beginning of period	$193,184	$ 2,088	$ (11,731)	$ -	$183,541
Net loss for the period	-	-	(1,029)	-	(1,029)
Issue of common shares (Note 9)	29,240	-	-	-	29,240
Share issue costs (Note 9)	(1,535)	-	-	-	(1,535)
Share-based compensation (Note 10)	-	664	-	-	664
Unrealized loss on investments (Note 3)	-	-	-	(1,680)	(1,680)
Transfer to net income of unrealized impairment loss on investments (Note 3)	-	-	-	1,680	1,680
Balance, end of period	$220,889	$ 2,752	$ (12,760)	$ -	$210,881

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Operating activities				
Net income (loss) for period	$ 5,473	$ (1,429)	$ 12,277	$ (1,029)
Non-cash items:				
Share-based compensation (Note 10)	611	241	1,436	664
Depletion, depreciation and accretion	7,699	5,101	19,613	13,390
Exploration and evaluation costs expensed (Note 4)	7	215	275	215
Gain on disposal of investments (Note 3)	-	-	(1,486)	-
Unrealized revaluation loss on investments	-	1,680	-	1,680
(Gain)/loss on disposal of oil and gas properties	20	22	46	(685)
Unrealized loss (gain) on commodity price contracts (Note 12)	(2,026)	314	(641)	213
	11,784	6,144	31,520	14,448
Net change in non-cash working capital items (Note 15)	(1,081)	289	(662)	2,883
	10,703	6,433	30,858	17,331
Financing activities				
Proceeds from issue of common shares - net of expenses (Note 9)	4,493	-	38,541	27,707
Increase (decrease) in bank indebtedness (Note 6)	20,425	6,656	28,278	(13,838)
	24,918	6,656	66,819	13,869
Investing activities				
Additions to exploration and evaluation assets (Note 4)	(245)	(716)	(1,633)	(15,963)
Additions to property and equipment (Note 5)	(30,181)	(23,001)	(84,752)	(44,596)
Cash portion of acquisitions of property and equipment and exploration and evaluation assets (Notes 4 and 5)	-	-	(30,150)	-
Proceeds on disposal of exploration and evaluation assets (Note 4)	-	-	-	1,395
Proceeds on disposal of property and equipment (Note 5)	-	-	-	18,100
Proceeds on disposal of investments (Note 3)	-	-	3,806	-
Net change in non-cash working capital items (Note 15)	(5,195)	10,628	15,052	9,864
	(35,621)	(13,089)	(97,677)	(31,200)
Change in cash during the period	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	$ -	$ -	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

Three and nine months ended September 30, 2014 and 2013

Tabular amounts in thousands of Canadian dollars, except per-share amounts
(unaudited)

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 unaudited condensed interim 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 IAS 34 Interim Financial Reporting, based on International Financial Reporting Standards ("IFRS") as issued and amended from time to time by the International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee ("IFRIC"), following the same accounting policies and methods of computation as used in the audited consolidated financial statements for the years ended December 31, 2013 and 2012, except as noted below. The financial statement note disclosures do not include all disclosures applicable to annual audited consolidated financial statements. Accordingly, the financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto as at and for the years ended December 31, 2013 and 2012.

These financial statements were authorized for issue by the Board of Directors on November 13, 2014.

Basis of Measurement

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

Use of Estimates and Judgments

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

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

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

- Note 3 – Measurement of fair value of investments
- Note 4 – Classification and measurement of exploration and evaluation assets
- Note 5 – Classification and measurement of property and equipment
- Note 7 – Measurement of decommissioning liability
- Note 8 – Measurement and utilization of tax assets
- Note 10 – Measurement of share-based compensation
- Note 12 – Measurement of fair value of commodity price contracts

Significant accounting policies

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 effect on the Company's financial statements.

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 the standard on Storm's financial statements.

Future accounting standards issued, but not yet effective, are described in Note 2 to the Company's audited consolidated financial statements for the year ended December 31, 2013.

3. INVESTMENTS

	September 30, 2014	December 31, 2013
Chinook Energy Inc. ("Chinook")	$ 2,050	$ 3,480

The investment in Chinook was transferred to Storm from a predecessor company in August 2010 and at September 30, 2014 the Company held a total of 1.0 million common shares (December 31, 2013 – 3.0 million).

In the first nine months of 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 three and nine months ended September 30, 2014, in the amounts of $0.2 million loss and $0.9 million, respectively (2013 – loss of $1.7 million for both periods charged against net income) was recognized in other comprehensive income.

4. EXPLORATION AND EVALUATION

	Nine Months Ended September 30, 2014	Year ended December 31, 2013
Balance, beginning of period	$ 87,396	$ 72,947
Acquisitions	78,952	-
Additions	1,633	16,863
Disposals	-	(755)
Exploration and evaluation expenditures expensed	(275)	(480)
Future decommissioning costs	1,103	812
Transfer to property and equipment	(1,351)	(1,991)
Balance, end of period	$ 167,458	$ 87,396

In the first nine months of 2014, the Company acquired two producing horizontal wells and 29 sections of undeveloped land at Umbach South for approximately $88.0 million, consisting of $30.0 million in cash and 13,629,442 common shares at a deemed price of $4.25 per share. This transaction did not constitute a business combination under IFRS.

5. PROPERTY AND EQUIPMENT

	Nine Months Ended September 30, 2014	Year ended December 31, 2013
Net book value, beginning of period	$ 152,472	$ 161,665
Cost		
Balance, beginning of period	$ 211,024	$ 176,990
Acquisitions	9,077	-
Additions	84,752	55,076
Disposals	-	(19,763)
Future decommissioning costs	5,991	(3,270)
Transfer from exploration and evaluation assets	1,351	1,991
Balance, end of period	$ 312,195	$ 211,024
Accumulated depletion and depreciation		
Balance, beginning of period	$ (58,552)	$ (15,325)
Depletion and depreciation	(19,372)	(18,935)
Reduction in carrying amount of property and equipment	-	(26,000)
Disposals	-	1,708
Balance, end of period	$ (77,924)	$ (58,552)
Net book value, end of period	$ 234,271	$ 152,472

6. BANK INDEBTEDNESS

As at September 30, 2014, the Company had an extendible syndicated revolving bank facility in the amount of $90.0 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 September 30, 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 credit line.

Subsequent to September 30, 2014, the Company's bankers approved an increase in the facility from $90.0 million to $130.0 million.

7. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning of 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 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 $23.8 million, which is expected to be paid over the next 25 years. A risk-free discount rate of 2.6% (2013 – 2.5%) and an inflation rate of 2.0% (2013 – 1.2%) was used to calculate the present value of the decommissioning obligation, amounting to $16.0 million.

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

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013
Balance, beginning of period	$ 8,689	$ 10,924
Obligations incurred	2,139	997
Obligations acquired	259	-
Obligations disposed	-	(2,515)
Obligations settled	(34)	(397)
Change in estimate(1)	4,730	(543)
Accretion expense	241	223
Balance, end of period	$ 16,024	$ 8,689

(1) Relates to changes in cost estimates in the first quarter of 2014 and inflation rate and discount rate changes in the third quarter of 2014 and a change in the discount rate in the fourth quarter of 2013.

8. DEFERRED INCOME TAXES

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

The Company has tax pools associated with exploration and evaluation assets and property and equipment assets of approximately $259.0 million as well as non-capital losses of approximately $130.0 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.

9. SHARE CAPITAL

Authorized

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

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 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)	1,683	7,265
Balance as at September 30, 2014	111,295	$ 351,048

(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 4)

(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 the first nine months of 2014, 1,683,000 common shares were issued upon the exercise of a like amount of stock options for proceeds of approximately $5.5 million and related prior period share-based compensation of $1.7 million was transferred to share capital from contributed surplus.

10. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company’s discretion, options to purchase common shares to directors, officers, employees and consultants. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, a total of 11,129,531 common shares are available for issuance. At September 30, 2014

options in respect of 4,045,500 common shares had been issued and were outstanding, and a total of 7,084,031 common shares are available for further grants under the stock option plan.
Details of the options outstanding at September 30, 2014 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2013	3,897	$ 2.47
Granted during period	1,832	$ 4.70
Exercised during period	(1,683)	$ 3.28
Outstanding at September 30, 2014	4,046	$ 3.14
Number exercisable at September 30, 2014	981	$ 1.91

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	2,174	2.1	$ 1.83	954	$ 1.87
$2.64 - $3.96	40	1.4	$ 3.04	27	$ 3.04
$3.97 - $4.68	1,832	3.5	$ 4.70	-	$ -
Total	4,046	2.7	$ 3.14	981	$ 1.91

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 nine months ended September 30, 2014 of $1.99 per option (2013 - $0.82) include the following:

	2014	2013
Share price	$ 4.70	$ 1.75
Exercise price	$ 4.70	$ 1.75
Volatility	56%	63%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Dividends	-	-
Risk-free interest rate	1.4%	1.3%

Share-based compensation expense of $611,000 and $1,436,000 was charged to the consolidated statement of income during the three and nine months ended September 30, 2014 (2013 - $241,000 and $664,000) with an equivalent offset to contributed surplus.

11. NET INCOME (LOSS) PER SHARE

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

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Net income (loss) for the period	$ 5,473	$ (1,429)	$ 12,277	$ (1,029)
Weighted average number of common shares outstanding – basic:				
Common shares outstanding at beginning of period	109,925	77,383	87,483	61,824
Effect of shares issued	1,029	-	19,633	8,668
Weighted average number of common shares outstanding – basic	110,954	77,383	107,116	70,492
Effect of outstanding options	1,572	-	1,712	-
Weighted average number of common shares outstanding - diluted	112,526	77,383	108,828	70,492
Net income (loss) per share				
- basic	$ 0.05	$ (0.02)	$ 0.11	$ (0.01)
- diluted	$ 0.05	$ (0.02)	$ 0.11	$ (0.01)

The dilutive factors are 1.7 million of the stock options described in Note 10. 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 the three and nine months ended September 30, 2014, 1.8 million and 1.3 million stock options were excluded from the calculation of dilutive shares as they were anti-dilutive to those periods. For the three and nine months ended September 30, 2013, all outstanding stock options were considered anti-dilutive as the Company incurred net losses during those periods.

12. FINANCIAL INSTRUMENTS

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

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide 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 September 30, 2014 fair value of $2.1 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

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 September 30, 2014 is as follows:

	Carrying Amount as at September 30, 2014
Accounts receivable	$ 11,461

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 September 30, 2014.

Market risk

Commodity prices

Commodity price risk is the risk that the fair value or 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 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 November 13, 2014, Storm has the undernoted commodity price contracts in place. The fair market value liability of these contracts of $607,000 (December 31, 2013 – $1,248,000) is included in current liabilities and the resulting unrealized mark-to-market gain of $641,000 (2013 – loss of $213,000) is recognized in the consolidated statement of income (loss) for the nine months ended September 30, 2014. Comparing the September 30 market value to the market value at June 30 results in a gain for the three months ended September 30, 2014 of $2,026,000 (2013 – loss of $314,000).

		WTI Crude Oil		AECO Natural Gas
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q4 – 2014	300 Bbls/day	$103.65	10,500 GJ/day	$3.51
Q1 – 2015	600 Bbls/day	$101.06	2,000 GJ/day	$3.62
Q2 – 2015	600 Bbls/day	$ 98.34	15,000 GJ/day	$3.33
Q3 – 2015	400 Bbls/day	$ 94.61	20,000 GJ/day	$3.36
Collars		Average Range (Cdn$/Bbl)		Average Range (Cdn$/GJ)
Q4 – 2014	150 Bbls/day	$100.00 - $107.20	4,000 GJ/day	$3.12 - $3.75
Q1 – 2015			28,000 GJ/day	$3.62 - $4.40

During the three and nine months ended September 30, 2014, the Company realized losses from commodity price contracts in place in the amount of $771,000 and $3,684,000 respectively (2013 – losses of $84,000 and $76,000).

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 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.

Sensitivities

Using the Company's actual production volumes, royalty rates and debt levels for the first nine months of 2014, the estimated after-tax effect that changes in certain factors would have on net income and net 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	$ 300,000	$ -
$0.10/Mcf change in the price of natural gas	$ 690,000	$ 0.01
1% change in the interest rate	$ 290,000	$ -

The Company's income tax assets are sufficient to eliminate taxes payable on any 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 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; 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.

13. CAPITAL MANAGEMENT

The Company's capital structure is comprised of shareholders' equity and bank indebtedness. The Company's objective when managing capital is to maintain financial flexibility to support capital programs that will replace production sold as well as production declines and provide a base for future 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.

14. RELATED PARTY TRANSACTIONS

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

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Salaries and short-term benefits	$ 285	$ 269	$ 1,056	$ 867
Share-based compensation	244	110	577	245
	$ 529	$ 379	$ 1,633	$ 1,112

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to Sept. 30, 2014	Three Months to Sept. 30, 2013	Nine Months to Sept. 30, 2014	Nine Months to Sept. 30, 2013
Accounts receivable	$ (3,468)	$ (1,726)	$ (5,276)	$ 1,738
Prepaids and deposits	2,628	25	286	73
Accounts payable and accrued liabilities	(5,436)	12,618	19,380	10,936
Change in non-cash working capital	$ (6,276)	$ 10,917	$ 14,390	$ 12,747
Relating to:				
Operating activities	$ (1,081)	$ 289	$ (662)	$ 2,883
Investing activities	(5,195)	10,628	15,052	9,864
	(6,276)	$ 10,917	$ 14,390	$ 12,747
Interest paid during the period	$ 321	$ 332	$ 691	$ 952
Income taxes paid during the period	$ -	$ -	$ -	$ -

16. COMMITMENTS

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

	2014	2015	2016	2017	2018
Office lease	$ 228	$ 916	$ 928	$ 928	$ 696
Gas transportation and processing commitments	1,966	7,393	3,573	2,976	-
Total	$ 2,194	$ 8,309	$ 4,501	$ 3,904	$ 696

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

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Calgary, Alberta, T2P 3G4 Canada
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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
kPa	One thousand pascals
LNG	Liquefied natural gas
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

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