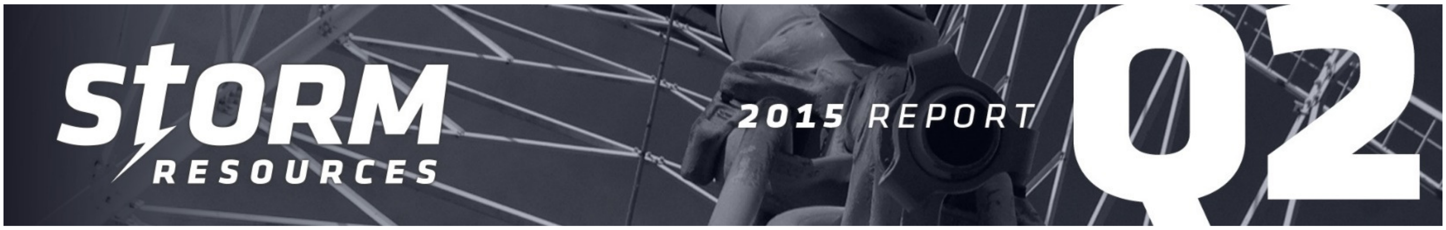

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
FINANCIAL				
Revenue from product sales(1)	18,461	21,701	36,972	42,508
Funds from operations(2)	8,170	11,076	21,882	19,736
Per share - basic ($)	0.07	0.10	0.20	0.19
Per share - diluted ($)	0.07	0.10	0.20	0.18
Net income (loss)	(4,191)	6,598	(7,756)	6,804
Per share - basic ($)	(0.04)	0.06	(0.07)	0.06
Per share - diluted ($)	(0.04)	0.06	(0.07)	0.06
Operations capital expenditures	8,864	33,640	44,544	55,983
Land and property acquisitions	-	-	-	88,051
Debt including working capital deficiency	28,051	41,837	28,051	41,837
Common shares (000s)				
Weighted average - basic	113,090	109,842	112,211	105,280
Weighted average - diluted	113,090	111,998	112,211	107,197
Outstanding end of period – basic	119,355	109,925	119,355	109,925
OPERATIONS				
(Cdn$ per Boe)				
Revenue	21.01	43.66	21.02	44.60
Royalties	(1.62)	(4.64)	(1.08)	(6.04)
Production	(8.56)	(9.41)	(8.61)	(10.11)
Transportation	(1.16)	(1.83)	(1.42)	(1.77)
Field operating netback	9.67	27.78	9.91	26.68
Hedging gains (losses)	2.02	(3.02)	5.19	(3.06)
General and administrative	(1.51)	(1.53)	(1.88)	(2.19)
Interest	(0.87)	(0.96)	(0.79)	(0.73)
Funds from operations - Boe	9.31	22.27	12.43	20.70
Barrels of oil equivalent per day (6:1)	9,657	5,462	9,716	5,266
Gas Production				
Thousand cubic feet per day	46,391	25,506	47,049	24,613
Price (Cdn$ per Mcf)	2.55	5.20	2.70	5.40
NGL production				
Barrels per day	1,602	762	1,548	743
Price (Cdn$ per barrel)	41.23	80.57	39.25	82.47
Oil Production				
Barrels per day	323	449	326	420
Price (Cdn$ per barrel)	57.58	99.27	50.29	96.40
Wells drilled				
Gross	-	7.0	6.0	12.0
Net	-	7.0	6.0	12.0

(1) Before hedging activities.
(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 21 of the attached MD&A.

PRESIDENT'S MESSAGE

2015 SECOND QUARTER HIGHLIGHTS

- During the second quarter, horizontal well performance at Umbach continued to meet or exceed expectations and there remained an inventory of nine horizontal wells (9.0 net) that had not yet started producing at the end of the quarter.

- Production averaged 9,657 Boe per day (20% oil plus NGL), a per-share increase of 69% from the previous year. Production was reduced by approximately 2,250 Boe per day by the planned maintenance turnaround of the McMahon Gas Plant which was shut in for 28 days in June. Prior to the turnaround, production in April and May averaged 11,900 Boe per day.

- NGL production was 1,602 barrels per day, an increase of 110% from the previous year which was the result of production growth from the liquids-rich Montney formation at Umbach where NGL recovery was 37 barrels per Mmcf sales in the quarter. The NGL price was $41.23 per barrel which was 67% of the average Edmonton light oil price (approximately 61% of the NGL mix is higher value condensate and pentanes).

- Activity in the quarter was focused at Umbach where two new horizontal wells came on production and a condensate stabilizer plus fuel gas conditioning skid was installed at the second field compression facility.

- Funds from operations was $8.2 million, or $0.07 per basic share, a decrease of 26% from the prior year. The decline was entirely due to declining commodity prices.

- Funds from operations was $9.31 per Boe, a year-over-year decrease of 58% with revenue per Boe declining by 52%, or $22.59 per Boe, being partially offset by a cash hedging gain of $2.02 per Boe.

- Controllable cash costs (operating, transportation, cash G&A and interest) were $12.10 per Boe which is a year-over-year decline of 12% or $1.63 per Boe and a decline of 9% from the previous quarter.

- Net loss was $4.2 million, or $0.04 per share, compared to net income of $6.6 million in the previous year. Loss on the sale of the non-core Grande Prairie properties was $1.6 million.

- Capital investment totaled $8.9 million with $8.3 million for facilities and pipelines at Umbach.

- Debt plus working capital deficiency was reduced to $28.1 million which was 0.9 times annualized second quarter cash flow. Storm's bank credit facility is currently $140.0 million.

- During the quarter, longer term processing commitments were increased to 54 Mmcf per day raw gas and longer term transportation commitments were increased to 51 Mmcf per day sales which represents approximately 65% of forecast production in the fourth quarter of 2015. In the second quarter, processing and transportation commitments covered approximately 40% of production.

- A bought deal financing of common shares was completed on June 10 with 8.0 million common shares being issued at a price of $4.55 per common share. Aggregrate net proceeds of $34.2 million will ultimately be used to accelerate growth into 2016.

- Subsequent to quarter end, the previously announced disposition of certain non-core properties in the Grande Prairie area of Alberta closed on July 15 with an effective date of July 1. Net proceeds of $23.7 million were used to reduce bank indebtedness. Second quarter production from these properties was 600 Boe per day (58% oil plus NGL).

OPERATIONS REVIEW

Storm has a focused asset base with large land positions in resource plays with multi-year drilling upside at Umbach and in the Horn River Basin (“HRB”).

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 100,000 net acres (141 net sections). To date, a total of 33.4 net horizontal wells (37.0 gross) have been drilled into the Montney formation with 24.4 net being on production.

Second quarter production from Umbach was 8,616 Boe per day, a year-over-year increase of 117%. Production was reduced by approximately 2,250 Boe per day as a result of the McMahon Gas Plant being shut in for 28 days in June for a planned maintenance turnaround. NGL production was 1,565 barrels per day, an increase of 125%, and represents a recovery of 37 barrels per Mmcf sales (approximately 61% of NGL is higher priced field condensate plus pentanes recovered at the gas plant). Revenue was $20.09 per Boe ($2.56 per Mcf sales and $40.43 per barrel of NGL), transportation costs were $1.01 per Boe, royalties were $1.54 per Boe (8% of revenue), operating costs were $7.80 per Boe and the operating netback was $9.74 per Boe.

Activity in the second quarter was mainly directed toward installing a condensate stabilizer and fuel gas conditioning unit at the second field compression facility at a cost of $6.7 million. These additions will improve condensate pricing and reduce operating costs. In addition, two horizontal wells (2.0 net) started producing in the second quarter. There is currently an inventory of nine horizontal wells (9.0 net) that have not started producing which includes three completed horizontal wells and six standing horizontal wells awaiting completion (includes three horizontal wells completed to date in the third quarter).

Storm’s two operated field compression facilities (both 100% working interest) have total capacity of 72 Mmcf per day raw gas with second quarter throughput totaling 42.6 Mmcf per day raw gas (54 Mmcf per day raw gas in April and May before the shut-down of the McMahon Gas Plant). It is anticipated that total capacity will be increased to 82 Mmcf per day raw gas in early October 2015 by investing $3.0 million to add a fifth compressor to the second facility.

Planning has been completed for a third field compression facility with start-up planned for early May 2016. The total cost is estimated to be $24.0 million for an initial capacity of 35 Mmcf per day raw gas which will be expandable to 70 Mmcf per day raw gas for an additional investment of $7.0 million. During 2015, $4.0 million will be invested to purchase major equipment for the third facility.

Longer term processing commitments at the McMahon and Stoddart Gas Plants have recently increased to total 54 Mmcf per day raw gas. Additionally, longer term commitments for sales pipeline capacity now total 52 Mmcf per day sales gas in 2016 after the transportation commitment on the Alliance Pipeline was recently increased 42 Mmcf per day sales gas for delivery to the Chicago market starting December 2015. The commitment on the Alliance Pipeline was made to diversify the markets where Storm’s natural gas is sold which will reduce exposure to the AECO – BC Station 2 price differential which has weakened since late 2014 and has averaged -$0.54 per GJ through the first half of 2015 (current forward strip for natural gas sold at Chicago in 2016 results in a differential of $-0.28 per GJ). For reference, the differential averaged -$0.21 per GJ from 2011 to 2014. Approximately 70% of Storm’s natural gas production was sold into the BC Station 2 market in the second quarter and received a lower price as a result of the wider differential. The price differential has increased as a result of unplanned maintenance outages on the TransCanada NGTL Pipeline system in Alberta combined with continued growth of natural gas production from northeast British Columbia.

As shown in the following summary, performance of the 2014 horizontal wells has shown significant improvement over earlier horizontal wells and further improvements are expected with the 2015 horizontal wells as the length and the number of frac stages are being increased. Note that calendar day rates for the 2015 horizontal wells have been reduced by the shut in of the McMahon Gas Plant for a maintenance turnaround.

	Frac Stages	IP 90 Cal Day Gross Raw Mmcf Per Day	IP 180 Cal Day Gross Raw Mmcf Per Day	1st Year Cal Day Gross Raw Mmcf Per Day
2011 – 2012 hz's (7 wells)	7 - 14	**1.9 Mmcf/d** 345 Boe/d sales 7 hz's	**1.4 Mmcf/d** 255 Boe/d sales 7 hz's	**1.3 Mmcf/d** 235 Boe/d sales 7 hz's
2013 hz's (6 wells)	16 - 18	**4.0 Mmcf/d** 725 Boe/d sales 6 hz's	**2.9 Mmcf/d** 525 Boe/d sales 6 hz's	**2.2 Mmcf/d** 400 Boe/d sales 6 hz's
2014 hz's (10 wells)	16 - 20	**4.7 Mmcf/d** 850 Boe/d sales 10 hz's	**4.9 Mmcf/d** 760 Boe/d sales 10 hz's	**3.7 Mmcf/d** 670 Boe/d sales 5 hz's
2015 hz's (4 wells)	18 - 22	**4.3 Mmcf/d** 780 Boe/d sales 4 hz's	**4.8 Mmcf/d** 870 Boe/d sales 1 hz	

Note: Sales volume is calculated using 8% shrinkage from raw gas to sales and 30 barrels of NGL per Mmcf sales.

Based on the performance of the 2013 to 2014 horizontal wells, Storm management is using a 6.3 Bcf raw gas type curve for internal budgeting purposes (this type curve has the same decline profile as the 3.2 and 4.4 Bcf raw gas 2P type curves used by InSite in the 2014 reserve evaluation). Using a cost of $5.4 million to drill, complete and tie in a horizontal well with 20 to 24 frac stages and a first year average rate of 3.6 Mmcf per day raw gas, the payout is approximately 30 months and the rate of return is 27% based on $2.80 per GJ at AECO, $2.40 per GJ at BC Station 2 and Cdn $61.00 per barrel for Edmonton light oil (approximate 2016 forward strip pricing held flat for the life of the well). See the presentation on Storm's website for further details. The actual cost to drill, complete, and tie in a horizontal well with 16 to 20 frac stages averaged $4.9 million in 2014, however, for the 2015 horizontal wells, this was increased to $5.4 million as the number of frac stages is being increased to 20 to 24. These results do not recognize any reduction in service costs in 2015.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the HRB (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Second quarter production averaged 282 Boe per day (100% natural gas), a year-over-year decline of 19%. The operating netback was $2.35 per Boe with revenue of $12.64 per Boe, transportation costs of $0.50 per Boe, an operating cost of $9.35 per Boe and a royalty of $0.45 per Boe, or 4% of revenue.

Grande Prairie Area, Northwest Alberta

Production in the second quarter was 759 Boe per day (47% oil plus NGL) and was reduced by 115 Boe per day due to a scheduled maintenance shutdown at a third party processing plant in May. In mid-January 2015, approximately 150 Boe per day was shut in as a result of the decline in the natural gas price and, on July 1, 2015, properties that produced 600 Boe per day in the second quarter were sold. The operating netback was $12.00 per Boe with revenue of $35.40 per Boe, a transportation cost of $3.19 per Boe, an operating cost of $17.22 per Boe and a royalty of $3.00 per Boe, or 9% of revenue.

There remains one property in the Grande Prairie area at Valhalla which produced 159 Boe per day in the second quarter (6% oil plus NGL).

HEDGING UPDATE

Realized cash gains in 2015 on Storm's commodity price hedges totaled $9.1 million up to the end of the second quarter. A summary of current hedges is provided below:

<table>
<tr><th></th><th colspan="2">H2 2015</th><th colspan="2">2016</th></tr>
<tr><td>Crude Oil</td><td></td><td></td><td>WTI Cdn $77.25/Bbl</td><td>500 Bopd</td></tr>
<tr><td rowspan="2">Natural Gas</td><td>AECO Cdn $3.36/GJ
($4.20/Mcf)</td><td>32,000 GJ/d
(25,600 Mcf/d)</td><td>AECO Cdn $3.00/GJ
($3.75/Mcf)</td><td>16,000 GJ/d
(13,000 Mcf/d)</td></tr>
<tr><td colspan="2"></td><td colspan="2">Fixed AECO - Stn 2 differential at
-$0.3375/GJ on 11,000 GJ/d</td></tr>
</table>

The purpose of Storm's commodity price hedges is to provide greater certainty regarding future cash flows and capital investment in order to support longer term growth plans. A maximum of 50% of current production (most recent monthly or quarterly average), before royalties, will be hedged; anticipated production growth is not hedged.

OUTLOOK

In the second quarter, production averaged 9,657 Boe per day which was lower than the forecast of 10,000 to 10,500 Boe per day provided with the release of first quarter results on May 13, 2015. Although production in April and May averaged 11,900 Boe per day, production in June was reduced by approximately 6,800 Boe per day due to the McMahon Gas Plant being shut in for 28 days in June for a planned maintenance turnaround. This was longer than the original expectation of 21 days and resulted in second quarter production being lower than forecast.

Production in the third quarter of 2015 is forecast to be 10,000 to 11,000 Boe per day and will depend largely on the duration and magnitude of constraints on the TransCanada NGTL pipeline system in Alberta. Production to date in the third quarter has averaged 9,000 Boe per day based on field estimates and has been impacted by unplanned restrictions on the Spectra Energy T-North Pipeline caused by restrictions on the TransCanada NGTL Pipeline system, unplanned outages and restrictions on the Alliance Pipeline and 5 days of unplanned downtime at the McMahon Gas Plant. Capital investment in the third quarter is expected to total $30.0 million with the majority directed to completing seven horizontal wells (7.0 net).

With the proceeds of the equity issue that closed in June, capital investment for 2015 is being increased to $106.0 million which will result in six more horizontal wells (6.0 net) being drilled and three more horizontal wells (3.0 net) being completed. None of these are scheduled to begin production until 2016. As a result of horizontal well performance continuing to exceed expectations, forecast production for the fourth quarter is being increased to 14,000 to 15,000 Boe per day which is a 6% increase from previous guidance after deducting 600 Boe per day for non-core property dispositions. This assumes that the restrictions on the TransCanada NGTL Pipeline system are largely eliminated by mid to late October.

2015 Guidance	November 13, 2014 Original Guidance	February 26, 2015 Revised Guidance	August 13, 2015 Revised Guidance
AECO natural gas price	$3.25 per GJ	$2.35 - $2.90 per GJ	$2.68 per GJ
BC STN 2 natural gas price	$3.00 per GJ	$2.05 - $2.60 per GJ	$2.01 per GJ
Edmonton light oil price	Cdn$83 per Bbl	Cdn$53 - $62 per Bbl	Cdn$59 per Bbl
Estimated average operating costs	$7.50 - $8.00 per Boe	$8.00 - $8.50 per Boe	$7.75 - $8.00 per Boe
Estimated average royalty rate (on production revenue before hedging)	12% - 14%	6% - 10%	7% - 8%
Estimated operations capital (excluding acquisitions & dispositions)	$110.0 million	$80.0 million	$106.0 million
Estimated land and property acquisitions/ (dispositions)	$0.0 million	$0.0 million	($23.7 million)
Estimated cash G&A net of recoveries	$5.3 million	$5.3 million	$5.3 million
Forecast fourth quarter production	14,000 – 14,500 Boe/d (18% oil + NGL)	14,000 – 14,500 Boe/d (19% oil + NGL)	14,000 – 15,000 Boe/d (18% NGL)
Forecast annual production	11,500 – 12,700 Boe/d (19% oil + NGL)	11,000 – 12,000 Boe/d (20% oil + NGL)	11,000 – 12,000 Boe/d (19% oil + NGL)
Umbach horizontal wells drilled	9 gross (9.0 net)	6 gross (6.0 net)	12 gross (12.0 net)
Umbach horizontal wells completed	14 gross (14.0 net)	11 gross (11.0 net)	14 gross (14.0 net)
Umbach horizontal wells starting production	16 gross (16.0 net)	14 gross (14.0 net)	14 gross (14.0 net)

Capital investment is focused entirely at Umbach in 2015 and will include:

- $67.0 million for drilling and completions;
- $4.2 million for larger diameter gathering pipelines and the pipeline connection to the Stoddart Gas Plant;
- $18.5 million to expand the second field compression facility from 27 to 64 Mmcf per day and install a condensate stabilizer and fuel gas conditioning unit;
- $4.0 million to order the long-lead-time equipment for the third field compression facility.

Total debt at the end of 2015 is forecast to be $67.0 million assuming average 2015 pricing of AECO $2.68 per GJ, BC Station 2 $2.01 per GJ and Edmonton light oil Cdn$59.00 per barrel which represents actual prices to date plus current forward strip pricing for the remainder of 2015. This would be approximately 1.3 times annualized funds from operations in the fourth quarter of 2015.

Preliminary guidance for 2016 is also being provided:

2016 Guidance	August 13, 2015 Preliminary Guidance
AECO natural gas price	$2.80 per GJ
BC STN 2 natural gas price	$2.40 per GJ
Edmonton light oil price	Cdn$61.00 per Bbl
Estimated average operating costs	$7.00 - $7.50 per Boe
Estimated average royalty rate (on production revenue before hedging)	8% - 10%
Estimated operations capital (excluding acquisitions & dispositions)	$106.0 million
Estimated cash G&A net of recoveries	$5.6 million

Forecast fourth quarter production	20,000 – 21,000 Boe/d (17% NGL)
Forecast annual production	16,000 – 19,000 Boe/d (17% oil + NGL)
Umbach horizontal wells drilled	12 gross (12.0 net)
Umbach horizontal wells completed	15 gross (15.0 net)
Umbach horizontal wells starting production	17 gross (17.0 net)

Capital investment in 2016 will also be directed entirely to Umbach and will include:

- $64.0 million for drilling and completions;
- $24.0 million to construct a third facility which will include a condensate stabilizer for planned start-up in early May 2016.

The corporate operating cost in 2015 is expected to decline below $7.25 per Boe in the fourth quarter from $8.56 per Boe in the second quarter. This is the result of selling higher cost properties in the Grande Prairie area as well as a reduction in operating costs at Umbach which are expected to decline to $6.75 per Boe in the fourth quarter due to continued production growth, recent longer term processing commitments which have a lower associated fee, and infrastructure projects including conversion of wells to salt water disposal and adding a fuel gas conditioning unit.

Proceeds from the equity issue that closed in June are being used to increase capital investment in 2015 which will accelerate production growth in 2016. This decision is supported by forward strip pricing for 2016 (approximately AECO $2.80 per GJ) which results in a half cycle rate of return of 27% for horizontal wells drilled at Umbach. Accelerating growth is also supported by the multi-year inventory of 170 horizontals that remain to be drilled in the upper Montney on the one-third of Storm's lands which have been delineated to date. In addition, in the current business environment, the cost to drill and complete horizontal wells is expected to be lower while further expanding the infrastructure at Umbach in 2016 will increase Storm's 'head start' on competitors in the area.

With a strong balance sheet, an evolving longer term infrastructure plan at Umbach, and with the Montney at Umbach providing Storm with a competitive advantage (increased revenue from NGL recovery plus a lower drilling and completion cost from the shallower depth), Storm remains well positioned for continued rapid growth into 2016 and beyond.

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

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

August 13, 2015

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

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

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

Forward-Looking Statements – Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated August 13, 2015 for the three and six months ended June 30, 2015.

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three and six months ended June 30, 2015. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2015, (ii) the Company's audited consolidated financial statements for the year ended December 31, 2014, and (iii) the press release issued by the Company on August 13, 2015, and other operating and financial information included in this report. All of these documents are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

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

The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated August 13, 2015.

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 six months ended June 30, 2015, prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the year ended December 31, 2014. The reporting and the measurement currency is the Canadian dollar.

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

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands of Canadian dollars. Comparative information is provided for the three and six month periods ended June 30, 2014.

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

- future commodity prices;
- future production volumes, production volumes by commodity and production declines;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific projects, activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition, construction and entry in service;
- future earnings or losses, including per-share amounts;
- future non-GAAP funds from operations and future cash flows, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future sources of funding for capital programs and future availability of such sources;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- development plans;

- estimates regarding the carrying amount of exploration and evaluation costs;
- estimates regarding the carrying amount of property and equipment;
- future debt levels;
- availability of credit facilities;
- future tax liabilities and future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- future royalties, operating costs, interest and general and administrative costs;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- future provisions for depletion and depreciation and accretion;
- expected share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in; facility and pipeline construction completed and brought into service; geographical areas developed; and
- changes to any of the foregoing.

Statements relating to “reserves” or “resources” are forward-looking statements, as they imply, based on estimates and assumptions, including assumptions regarding future prices, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include the material uncertainties and risks described or incorporated by reference in this MD&A under “Critical Accounting Estimates”; “Risk Assessment”; “Financial Reporting Update”; 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”; “Accretion”; “Interest and Finance Costs”; “Gain on Disposal of Investments”; “Realized and Unrealized Gain (Loss) on Commodity Price Contracts”; “Income Taxes”; “Other Comprehensive Income (Loss)”; “Financial Resources and Liquidity”; “Investments”; “Accounts Payable and Accrued Liabilities”; “Decommissioning Liability”; “Shareholders’ Equity”; “Contractual Obligations”; industry conditions including commodity prices, capacity constraints and access to processing facilities and to market for production, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and related costs including future royalties, production costs and future development costs, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, ability to access sufficient capital from internal and external sources and the ability of the Company to realize value from acquired assets and corporations. All of these caveats should be considered in the context of current economic conditions, in particular low prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm’s actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

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

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles (“GAAP”). Specifically, “funds from operations”, “funds from operations per share”, “netbacks”, “field operating income”, “total operating income”, “cash costs”, and measurements “per Boe” do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-

GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. In particular, funds from operations is not intended to represent, or be equivalent to, cash flow from operating activities calculated in accordance with GAAP, which is measured on the Company's consolidated statements of cash flows. Funds from operations and similar non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, analysts and other parties. These measurements are also used by lenders to measure compliance with debt covenants and thus set interest costs. Reference is made to the discussion in this MD&A under "Non-GAAP Funds from Operations and Funds from Operations per Share" and to "Cash Flows from Operating Activities".

OPERATIONAL AND FINANCIAL RESULTS

Overview

During the second quarter of 2015 Storm faced continuing commodity price headwinds which were exacerbated by industry-related operational difficulties. Commodity pricing continued to be weak across Storm's production spectrum. Additionally, scheduled maintenance and turnaround at the McMahon gas processing facility, to which approximately 70% of Storm's Umbach production is directed for processing, resulted in production being shut in for a period of 28 days in the month of June, or seven days longer than anticipated. Further, pipeline constraints on the TCPL system in Alberta had a spillover effect on to the Station 2 delivery point in British Columbia. Additional natural gas volumes being directed to Station 2 resulted in a widening of the Station 2 – AECO differential in the quarter, concurrently with continuing decline in the price of natural gas.

The consequence was that daily production volumes averaged 9,657 Boe for the quarter which was largely the same as the first quarter of 2015. Funds from operations for the quarter, excluding hedging gains, was also the same as the first quarter.

Although the Company's existing financial position was satisfactory, favourable market conditions in May enabled the Company to issue eight million common shares, for net proceeds of approximately $34.3 million. Shares outstanding increased by 7%. Also, in July, the Company closed the sale of the majority of its Alberta properties for proceeds of approximately $23.7 million. Production from these properties approximated 600 Boe per day in the second quarter. The properties sold were no longer core to the Company's business and investment therein over the last two years had been minimal. Incorporating the sale proceeds, pro forma debt at the end of the second quarter was $28.1 million, or debt to annualized second quarter funds from operations of 0.8 times. It merits emphasis that second quarter cash flow was particularly weak for the reasons set out above. Proceeds from the equity issue and the property disposal were used to reduce bank debt. These two transactions give Storm additional financial capacity to rapidly expand its capital program in response to improved economics, or to take advantage of opportunities which may emerge in an increasingly challenging market place. Storm's bank line amounts to $140.0 million.

Low prices and access to market have affected prices for each of natural gas, natural gas liquids and crude oil. The table below illustrates the remarkable downward drift in commodity pricing over the last six quarters.

Average Quarterly Per-Unit Realized Price (Cdn$)	Natural Gas (Mcf)		Natural Gas Liquids (Bbl)		Crude Oil (Bbl)		Boe	
Q1 – 2014	$5.63	100%	$84.49	100%	$93.08	100%	$45.62	100%
Q2 – 2014	$5.20	92%	$80.57	95%	$99.27	107%	$43.66	96%
Q3 – 2014	$4.48	80%	$73.09	87%	$90.31	97%	$37.80	83%
Q4 – 2014	$3.85	68%	$56.15	66%	$68.01	73%	$29.99	66%
Q1 – 2015	$2.85	51%	$37.10	44%	$43.08	46%	$21.04	46%
Q2 – 2015	$2.55	45%	$41.23	49%	$57.58	62%	$21.01	46%

Storm's production of natural gas amounts to 80% of total Boe production, with NGL amounting to 17% and crude oil 3%. Thus the modest price recovery in crude oil and NGL in the second quarter was of limited benefit to the Company.

Approximately 50% of Storm's natural gas production is sold at the Station 2 daily index price, 20% at the AECO monthly index price less $0.20 per GJ, 25% at the AECO monthly index price adjusted for the AECO - Station 2 differential, and 5% at the AECO daily index price. During the second quarter, as a result of pipeline capacity curtailments in Alberta, increasing volumes of natural gas were directed to Station 2. The result was a widening of the differential between the Station 2 index and AECO pricing as follows:

Cdn$/GJ	AECO Monthly Index	AECO Daily Index	Station 2 Daily Index	Daily Index Differential	
				$	%
Q1 – 2014	4.51	5.42	4.94	(0.48)	(9%)
Q2 – 2014	4.43	4.44	4.20	(0.24)	(5%)
Q3 – 2014	4.00	3.81	3.54	(0.27)	(7%)
Q4 – 2014	3.80	3.41	2.93	(0.48)	(14%)
Q1 – 2015	2.80	2.60	2.02	(0.58)	(22%)
Q2 – 2015	2.53	2.52	2.01	(0.51)	(20%)

As curtailments are eased on the TCPL system in Alberta, it is a reasonable expectation that the AECO - Station 2 differential will narrow. However, it is not yet clear when this will happen.

In the face of such a hostile operating environment, Storm is focusing on cost reduction and capital management. The Company's balance sheet has been strengthened and total costs have been reduced across all categories of controllable costs. High operating cost properties have been sold and the inventory of standing wells means that the Company can maintain or increase production through the incurrence of completion and tie-in costs only. Importantly, the Company has the financial capacity and an asset base providing a deep inventory of opportunity which enables the Company to grow rapidly in response to a more benign commodity price environment.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				Three Months to June 30, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	42,308	1,565	-	8,616
Horn River Basin – NE BC	1,692	-	-	282
Grande Prairie – AB	2,391	37	323	759
Total	46,391	1,602	323	9,657

				Three Months to June 30, 2014
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	19,702	695	-	3,979
Horn River Basin – NE BC	2,083	-	-	347
Grande Prairie – AB	3,721	67	449	1,136
Total	25,506	762	449	5,462

				Six Months to June 30, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	42,596	1,498	-	8,598
Horn River Basin – NE BC	1,688	-	-	281
Grande Prairie – AB	2,765	50	326	837
Total	47,049	1,548	326	9,716

Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Six Months to June 30, 2014 Boe/d
Umbach – NE BC	18,564	676	-	3,770
Horn River Basin – NE BC	2,180	-	-	363
Grande Prairie - AB	3,869	67	420	1,133
Total	24,613	743	420	5,266

In the second quarter of 2015, average Boe-per-day volumes increased by 77% when compared to the second quarter of 2014 and fell by 1% when compared to the first quarter of 2015. Lack of growth in the second quarter was due to the shut down for 28 days in the quarter of a key processing facility for maintenance. For the six month period ended June 30, 2015, average Boe production increased by 85% year over year. Production increases for natural gas and NGL, when compared to the same quarter in 2014, are attributed to growth at Umbach where the Company produced from 29 wells (25.4 net) during the quarter. Crude oil production decreased as a result of natural declines.

Daily production per million shares outstanding for the second quarter of 2015 averaged 85 Boe per day, compared to 49 Boe per day for the second quarter of 2014 and 88 Boe per day for the immediately preceding quarter. The reduction in production per share corresponds to the dilutive effect of an equity issue in the second quarter.

HRB produces dry natural gas, while Umbach produces natural gas and associated NGL. Production in Alberta for the second quarter of 2015 approximated 42% light oil, with an average API of 37 degrees, 53% natural gas and 5% NGL. In July the Company sold the majority of the Alberta properties for proceeds of approximately $23.7 million. Production for the second quarter of 2015 from the remaining properties in Alberta was 159 Boe per day, primarily natural gas.

Average Daily Production

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Natural gas (Mcf/d)	46,391	25,506	47,049	24,613
Natural gas liquids (Bbls/d)	1,602	762	1,548	743
Crude oil (Bbls/d)	323	449	326	420
Total (Boe/d)	9,657	5,462	9,716	5,266

Production Profile and Per-Unit Prices(1)

	Three Months to June 30, 2015		Three Months to June 30, 2014		Six Months to June 30, 2015		Six Months to June 30, 2014	
	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas - Mcf	80%	$ 2.55	78%	$ 5.20	81%	$ 2.70	78%	$ 5.40
Natural gas liquids - Bbl	17%	41.23	14%	80.57	16%	39.25	14%	82.47
Crude oil - Bbl	3%	57.58	8%	99.27	3%	50.29	8%	96.40
Per Boe	100%	$ 21.01	100%	$ 43.66	100%	$ 21.02	100%	$ 44.60

(1) Before realized hedging gains of $2.02 per Boe for the three months ended June 30, 2015 and $5.19 per Boe for the six months ended June 30, 2015. In 2014, there were hedging losses of $3.02 per Boe for the three months ended June 30, 2014 and $3.06 per Boe for the six months ended June 30, 2014.

Approximately 50% of Storm's natural gas production is sold at the Station 2 daily index price, 20% at the AECO monthly index price less $0.20 per GJ, 25% at the AECO monthly index price adjusted for the AECO - Station 2 differential, and 5% at the AECO daily index price. During the second quarter, as a result of pipeline capacity curtailments in Alberta, increasing volumes of natural gas were directed to Station 2. Average quarterly index prices in gigajoules are as follows:

(Cdn$/GJ)	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
AECO Monrhly Index	$ 2.53	$ 4.43	$ 2.66	$ 4.47
AECO Daily Index (spot)	$ 2.52	$ 4.44	$ 2.56	$ 4.93
BC Station 2 Daily Index (spot)	$ 2.01	$ 4.20	$ 2.02	$ 4.57

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

Station 2 is a less liquid market from AECO and usually Station 2 trades at a modest discount to the AECO price (equal to the pipeline transportation tariff between both markets). However, in the first half of 2015, transmission interruptions in Alberta resulted in increased natural gas volumes moving to the Station 2 market. There was also growth in natural gas production in areas where production is normally directed to Station 2. The consequence was a considerable widening in the Station 2 - AECO differential, from Station 2 being 9% below the AECO price in the first quarter of 2014, rising to 14% in the final quarter of 2014 and to 21% in the first half of 2015. It should be recognized that the widening Station 2 – AECO price differential has emerged in a period of falling natural gas prices. It is uncertain when the circumstances that led to the widening differential will change and thus lead to a lower differential.

Storm's realized price for the second quarter was $2.55 per Mcf, with the price higher than index prices as a result of sales gas at Umbach and Grande Prairie having a higher heat content.

The realized price for NGL in the second quarter of 2015 fell 49% relative to the second quarter of 2014 and increased 11% compared to the first quarter of 2015 as liquids prices started to rebound along with crude oil prices in the second quarter. The NGL stream contained 61% condensate and pentanes which are generally priced with reference to crude oil prices and received an average price of $59.24 per barrel. However, the price for propane collapsed with Storm's realized plantgate price being -$7.52 per barrel during the quarter.

As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production will also increase.

For the second quarter, WTI averaged US$57.94 per barrel and Edmonton light oil was Cdn$67.72 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$3.51 per barrel, compared to Cdn$6.70 per barrel in the second quarter of 2014. Due to quality and gravity differentials, Storm's average crude oil sales price for the second quarter of 2015 was $10.14 per barrel lower than the Edmonton light oil reference price. Subsequent to the sale of the Alberta properties, production of light oil will be insignificant in the context of total corporate production.

On a per-Boe basis, the realized price for the second quarter of 2015 declined by 52% relative to the second quarter of 2014 and was flat to the first quarter of 2015.

Revenue from Product Sales(1)

(000s)	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Natural gas (Mcf/d)	$ 10,759	$ 12,060	$ 23,004	$ 24,077
Natural gas liquids (Bbls/d)	6,011	5,585	10,996	11,095
Crude oil (Bbls/d)	1,691	4,056	2,972	7,336
Total	$ 18,461	$ 21,701	$ 36,972	$ 42,508

(1) Excludes hedging gains and losses.

Revenue from product sales for the second quarter of 2015 decreased by 15% when compared to the second quarter of 2014, with an average price per Boe for the second quarter of 2015 of $21.01, a decrease of 52% compared to the second quarter of 2014. However, this was offset by production growth of 77% year over year. The disconnect between growth in production and declining revenue is a result of price declines, as follows:

Realized Prices per Commodity Unit	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Natural gas (Mcf)	$ 2.55	$ 5.20	$ 2.70	$ 5.40
Natural gas liquids (Bbls)	$ 41.23	$ 80.57	$ 39.25	$ 82.47
Crude oil (Bbls)	$ 57.58	$ 99.27	$ 50.29	$ 96.40
Total (Boe)	$ 21.01	$ 43.66	$ 21.02	$ 44.60

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – Q2 2014	$ 12,060	$ 5,585	$ 4,056	$ 21,701
Effect of increased (decreased) production	9,883	6,159	(1,138)	16,667
Effect of change in product prices	(11,184)	(5,733)	(1,227)	(19,907)
Revenue from product sales – Q2 2015	$ 10,759	$ 6,011	$ 1,691	$ 18,461

Hedging

The Company had in place the following hedging arrangements at June 30, 2015:

	WTI Crude Oil		AECO Natural Gas	
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q3 – 2015			34,000 GJ/day	$3.27
Q4 – 2015			30,000 GJ/day	$3.47
Jan – Dec 2016	500 Bbls/day	$ 77.25	15,000 GJ/day	$3.00
Q1 – 2016			5,000 GJ/day	$3.06
Jan – Dec 2016			15,000 GJ/day	$3.00
Jan – Dec 2016			11,000 GJ/day	AECO - Stn 2 diff ($0.3375)/GJ

During the second quarter of 2015, the Company realized gains from hedges in the amount of $1.8 million, compared to losses of approximately $1.5 million in the second quarter of 2014. During the first half of 2015, the Company realized gains from hedges in the amount of $9.1 million compared to losses of $2.9 million in the first half of 2014. In January 2015 the Company terminated all of the Company's then existing crude oil contracts in exchange for $5.1 million. This amount is recognized as part of the realized gain on commodity price contracts in the consolidated statement of loss for the six months to June 30, 2015. Details by commodity of realized gains and losses are provided on pages 19-20. The fair market value of hedges in place at June 30, 2015 was $5.2 million.

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

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

Royalties

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 1,426	$ 2,304	$ 1,899	$ 5,753
Percentage of revenue from product sales	8%	11%	5%	14%
Per Boe	$ 1.62	$ 4.64	$ 1.08	$ 6.04

Royalties in the second quarter of 2015 decreased by 38% when compared to the same quarter of 2014 and decreased by 67% when comparing the first half of 2015 to the first half of 2014. Decreased production revenue as a result of lower commodity pricing was the primary driver of decreased royalties; however, royalties also decreased as a result of the receipt in January 2015 of an infrastructure royalty credit at Umbach which reduced 2015 royalties by $1.0 million.

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 was received in the first quarter of 2015. During 2014, approval was received for an additional net amount of $4.7 million of royalty credits for a facility and related gathering pipelines and, subsequent to June 30, 2015, the Company received approval for a further $5.5 million. Future royalties will thus be reduced by $10.2 million. The timing of receipt of future credits is dependent on commodity prices and cannot be readily forecast; correspondingly, royalty rates reported in future quarters could vary considerably depending on when future credits are received.

In HRB, the Company received approval for an infrastructure royalty credit of $1.0 million in 2012 and received $0.3 million in 2014. Timing of receipt of the remaining $0.7 million is dependent on the natural gas price.

In March 2014, the British Columbia provincial government announced the expansion of the Deep Well Royalty Credit Program by extending royalty credits to all horizontal wells. Hitherto, wells with a vertical depth of less than 1,900 metres were not eligible for the program. Horizontal wells at Umbach, drilled after April 1, 2014, will receive a royalty credit of $0.5 million to $0.7 million per well, depending on the total measured vertical depth of the well. In conjunction with this change, wells that are eligible for this expanded credit program will bear a minimum royalty at a rate of 6%. Again, the timing of receipt of royalty credits under the program cannot be readily predicted: correspondingly, the royalty rate reported in future quarters may vary considerably.

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

Production of NGL is subject to a base royalty rate of 20% in British Columbia and approximately 25% to 30% in Alberta. This rate is subject to reduction if the royalty credit programs above have application.

Production Costs

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 7,523	$ 4,676	$ 15,147	$ 9,638
Percentage of revenue from product sales	41%	22%	41%	23%
Per Boe	$ 8.56	$ 9.41	$ 8.61	$ 10.11

Total production costs for the second quarter increased by 61% when compared to the second quarter of 2014 and decreased by 1% when compared to the first quarter of 2015. The year-over-year increase in total production costs is largely aligned with increased production at Umbach as per-Boe charges have continued to decline.

Production costs per Mcf of natural gas for the second quarter averaged $1.66 and production costs per barrel of crude oil for the same period averaged $17.90, with total production costs averaging $8.56 per Boe. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for the second quarter of 2014 were $1.74 per Mcf of natural gas and $15.64 per barrel for crude oil, with total production costs averaging $9.41 per Boe. For the six month periods to June 30, per-Boe production costs averaged $8.61 in 2015 and $10.11 in 2014.

Production costs per Boe have fallen due to production growth as well as lower cost natural gas growing as a percentage of the Company’s production base.

Although per-unit production costs have fallen year over year, they have nearly doubled as a percentage of production revenue, a striking illustration of the effect falling commodity prices have on the profitability of the Company’s business.

Transportation Costs

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 1,023	$ 909	$ 2,499	$ 1,691
Percentage of revenue from product sales	6%	4%	7%	4%
Per Boe	$ 1.16	$ 1.83	$ 1.42	$ 1.77

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 second quarter of 2015 increased by 13% over the same quarter of 2014. For the six month periods to June 30, transportation costs increased 48% due to higher production volumes while per-Boe transportation costs for both periods declined 36% and 20%, respectively, due to lower oil and NGL trucking charges as part of the overall transportation cost structure.

Field Netbacks

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

Three Months to June 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.55	$ 41.23	$ 57.58	$ 21.01
Royalties	(0.12)	(5.97)	(1.47)	(1.62)
Production costs	(1.66)	-	(17.90)	(8.56)
Transportation costs	(0.16)	(1.60)	(4.36)	(1.16)
Field operating income before hedging	$ 0.61	$ 33.66	$ 33.85	$ 9.67
Realized hedging gains (losses)	0.42	-	-	2.02
Total operating income per commodity unit	$ 1.03	$ 33.66	$ 33.85	$ 11.69
Total operating income (000s)	$ 4,364	$ 4,908	$ 994	$ 10,266

Three Months to June 30, 2014	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 5.20	$ 80.57	$ 99.27	$ 43.66
Royalties	0.01	(18.15)	(26.43)	(4.64)
Production costs	(1.74)	-	(15.64)	(9.41)
Transportation costs	(0.18)	(2.78)	(7.48)	(1.83)
Field operating income before hedging	$ 3.29	$ 59.64	$ 49.72	$ 27.78
Realized hedging gains (losses)	(0.47)	-	(9.93)	(3.02)
Total operating income per commodity unit	$ 2.82	$ 59.64	$ 39.79	$ 24.76
Total operating income (000s)	$ 6,553	$ 4,133	$ 1,627	$ 12,313

Six Months to June 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.70	$ 39.25	$ 50.29	$ 21.02
Royalties	(0.01)	(6.11)	(2.41)	(1.08)
Production costs	(1.65)	-	(18.67)	(8.61)
Transportation costs	(0.17)	(2.66)	(4.62)	(1.42)
Field operating income before hedging	$ 0.87	$ 30.48	$ 24.59	$ 9.91
Realized hedging gains (losses)	0.47	-	86.93	5.19
Total operating income per commodity unit	$ 1.34	$ 30.48	$ 111.52	$ 15.10
Total operating income (000s)	$ 11,433	$ 8,540	$ 6,589	$ 26,562

Six Months to June 30, 2014	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 5.40	$ 82.47	$ 96.40	$ 44.60
Royalties	(0.40)	(16.62)	(22.98)	(6.04)
Production costs	(1.83)	-	(19.20)	(10.11)
Transportation costs	(0.19)	(2.81)	(5.94)	(1.77)
Field operating income before hedging	$ 2.98	$ 63.04	$ 48.28	$ 26.68
Realized hedging gains (losses)	(0.50)	-	(9.17)	(3.06)
Total operating income per commodity unit	$ 2.48	$ 63.04	$ 39.11	$ 23.62
Total operating income (000s)	$ 11,056	$ 8,480	$ 2,977	$ 22,513

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

Total operating income in the second quarter of 2015 declined by 17% when compared to the same quarter of 2014. Per Boe, excluding hedging gains and losses, field operating income fell by 65% in the second quarter of 2015 in comparison to the same quarter of 2014, and by 5% compared to the first quarter of 2015. For the second quarter, year-over-year royalties, production and transportation costs per Boe each fell considerably, but these gains were insufficient to counter the effect of reduced commodity prices which saw the per-Boe realization fall by $22.65, or, for the Company, an unprecedented 52%. Compared to the first quarter of 2015, operating and transportation costs fell, with royalties increasing due to an infrastructure royalty credit received in the first quarter.

Cash costs per Boe, comprising production costs, transportation, interest and general and administrative costs, amounted to $12.10 for the second quarter of 2015, $13.73 for the equivalent quarter of 2014 and $13.29 for the first quarter of 2015. Comparing the second quarter of 2015 to the same quarter in 2014, all components of cash costs decreased on a per-Boe basis. Compared to the first quarter of 2015, increased bank debt resulted in higher interest costs. All other cash costs declined on a per-Boe basis.

General and Administrative Costs

Total Costs	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period – before recoveries	$ 1,684	$ 1,351	$ 4,536	$ 3,097
Overhead recoveries	(355)	(593)	(1,238)	(1,012)
Charge for period – net of recoveries	$ 1,329	$ 758	$ 3,298	$ 2,085
Per Boe	$ 1.51	$ 1.53	$ 1.88	$ 2.19

Gross general and administrative costs for the second quarter and first half of 2015 increased by 25% and 46%, respectively, when compared to the same periods of 2014. The year-on-year increase in general and administrative costs is largely attributable to increased personnel costs, including employee performance bonuses paid in March 2015. Overhead recoveries fell in the second quarter of 2015 compared to the prior year and to the first quarter of 2015 due to lower field activity.

Share-Based Compensation

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 783	$ 568	$ 1,768	$ 825
Per Boe	$ 0.89	$ 1.14	$ 1.01	$ 0.87

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 38% in the second quarter of 2015 compared to the same quarter of 2014. The year-over-year increase in share-based compensation in both the three and six month periods of 2015 is attributable to stock options granted in March and December of 2014.

Depletion and Depreciation

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Depletion	$ 7,673	$ 5,299	$ 15,498	$ 10,317
Depreciation	1,005	766	2,399	1,447
Charge for period	$ 8,678	$ 6,065	$ 17,897	$ 11,764
Per Boe	$ 9.88	$ 12.20	$ 10.18	$ 12.34

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 for the second quarter of 2015 resulted in the total charge for depletion increasing year over year by 45% in the second quarter of 2015, which is less than the 77% increase in production. However, the year-over-year per-Boe charge fell by 19%, as the finding and development cost for proved plus probable reserves has declined, reflecting Storm's successful drilling program. Increased depreciation charges year over year corresponds to increased investment in facilities.

Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at June 30, 2015 and determined that no impairment adjustment was required.

Exploration and Evaluation Costs Expensed

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ -	$ 116	$ 103	$ 268
Per Boe	$ -	$ 0.23	$ 0.06	$ 0.28

Exploration and evaluation costs is a non-cash charge representing the cost of undeveloped lands with lease terms expiring in the quarter. There were no such expiries in the second quarter of 2015.

Accretion

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 137	$ 83	$ 270	$ 150

Accretion represents the time value increase for the period of the Company's decommissioning liability. The increased charge for accretion for the three and six month periods of 2015 compared to the same periods of 2014 is due to continuing field investment and to changes in estimates of future costs and discount rates.

Interest and Finance Costs

(000's)	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Charge for period	$ 765	$ 479	$ 1,382	$ 692
Percentage of revenue from product sales	4%	2%	4%	2%
Per Boe	$ 0.87	$ 0.96	$ 0.79	$ 0.73

Interest costs in 2015, for both the three and six month periods, increased year over year as a result of increased bank borrowings corresponding to an expanding production and asset base. The equity issue in June 2015, and the sale of the Alberta properties in July 2015, will reduce future 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. There have been no further sales of Chinook common shares.

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

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

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

	Three Months to June 30, 2015				Three Months to June 30, 2014			
Realized gain (loss)								
Crude oil	$ -	$	-	/Bbl	$ (406)	$	(9.93)	/Bbl
Natural gas	1,775	$	0.42	/Mcf	(1,093)	$	(0.47)	/Mcf
Total realized gain (loss) – cash	$ 1,775	$	2.02	/Boe	$ (1,499)	$	(3.02)	/Boe

	Six Months to June 30, 2015				Six Months to June 30, 2014			
Realized gain (loss)								
Crude oil	$ 5,137	$	87.06	/Bbl	$ (698)	$	(9.17)	/Bbl
Natural gas	3,998	$	0.47	/Mcf	(2,215)	$	(0.50)	/Mcf
Total realized gain (loss) – cash	$ 9,135	$	5.19	/Boe	$ (2,913)	$	(3.06)	/Boe

	Three Months to June 30, 2015				Three Months to June 30, 2014			
Unrealized gain (loss)								
Crude oil – change in fair value	$ (99)	$	(3.37)	/Bbl	$ (59)	$	(1.44)	/Bbl
Natural gas – change in fair value	(800)	$	(0.19)	/Mcf	1,611	$	0.69	/Mcf
Total unrealized gain (loss) – non-cash	$ (899)	$	(1.02)	/Boe	$ 1,552	$	3.12	/Boe

	Six Months to June 30, 2015				Six Months to June 30, 2014			
Unrealized gain (loss)								
Crude oil – change in fair value	$ (4,960)	$	(84.05)	/Bbl	$ (526)	$	(6.92)	/Bbl
Natural gas – change in fair value	(2,776)	$	(0.33)	/Mcf	(859)	$	(0.19)	/Mcf
Total unrealized gain (loss) – non-cash	$ (7,736)	$	(4.40)	/Boe	$ (1,385)	$	(1.46)	/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 June 30, 2015	Maximum Annual Deduction
Canadian oil and gas property expense	$ 43,000	10%
Canadian development expense	98,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	83,000	20 - 100%
Operating losses	146,000	100%
Other	5,000	20 - 100%
Total	$ 397,000	

Net Income (Loss)

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Net income	$ (4,191)	$ 6,598	$ (7,756)	$ 6,804
Per basic and diluted share	$ (0.04)	$ 0.06	$ (0.07)	$ 0.06

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 three and six months ended June 30, 2015, losses of $60,000 and $110,000, respectively, were recognized in other comprehensive income representing the reversal of prior mark- to-market gains in value of the investment in Chinook.

Listed Securities	Holding	Number of Shares[(1)]	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Chinook Energy Inc.	Common Shares	1,000,000	$ (60)	$ 1,060	$ (110)	$ 1,060
Other comprehensive income (loss) for period			$ (60)	$ 1,060	$ (110)	$ 1,060

(1) Shares owned at June 30, 2015.

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

	Three Months to June 30, 2015		Three Months to June 30, 2014		Six Months to June 30, 2015		Six Months to June 30, 2014	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds from operations	$ 8,170	$0.07	$11,076	$0.10	$21,882	$0.20	$19,736	$0.18

Non-GAAP funds from operations for the second quarter of 2015 decreased by 26% from the second quarter of 2014, and for the six month period increased by 11% when comparing 2015 to 2014. Compared to the immediately prior quarter, non-GAAP funds from operations for the quarter ended June 30, 2015 fell by 40%.

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

Cash Flows from Operating Activities

	Three Months to June 30, 2015		Three Months to June 30, 2014		Six Months to June 30, 2015		Six Months to June 30, 2014	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Non-GAAP funds from operations	$ 8,170	$0.07	$11,076	$0.10	$21,882	$0.20	$19,736	$0.18
Net change in non-cash working capital items	623	$0.01	1,274	0.01	848	0.01	419	0.00
Cash from operating activities	$ 8,793	$0.08	$12,350	$0.11	$22,730	$0.21	$20,155	$0.18

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 June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Revenue from product sales	21.01	43.66	21.02	44.60
Realized hedging gains (losses)	2.02	(3.02)	5.19	(3.06)
Royalties	(1.62)	(4.64)	(1.08)	(6.04)
Production	(8.56)	(9.41)	(8.61)	(10.11)
Transportation	(1.16)	(1.83)	(1.42)	(1.77)
General and administrative	(1.51)	(1.53)	(1.88)	(2.19)
Interest	(0.87)	(0.96)	(0.79)	(0.73)
Funds from operations	9.31	22.27	12.43	20.70
Share-based compensation	(0.89)	(1.14)	(1.01)	(0.87)
Depletion, depreciation and accretion	(10.04)	(12.37)	(10.33)	(12.50)
Exploration and evaluation costs expensed	-	(0.23)	(0.06)	(0.28)
Gain on disposal of investments	-	2.40	-	1.56
Unrealized revaluation gain (loss) on investments	(0.25)	(0.76)	(0.13)	-
Loss on assets held for sale	(1.87)	-	(0.93)	-
Gain (loss) on disposal of oil and gas properties	-	(0.03)	-	(0.03)
Unrealized gain (loss) on commodity price contracts	(1.02)	3.12	(4.40)	(1.46)
Net income (loss) per Boe	(4.76)	13.26	(4.43)	7.12

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the beginning of 2014, Storm's bank facility amounted to $65.0 million. In May and November 2014, the facility was increased to $90.0 million and $130.0 million respectively, in recognition of production and reserve growth at Umbach. In April 2015, the facility was again increased to $150.0 million. In July 2015, subsequent to the disposal of certain non-core assets in Alberta, the facility was reduced to $140.0 million.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that net debt, including working capital deficiency, cannot 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 changes subject to approval by the Board of Directors. Management is accountable to the Board of Directors for the execution of the business plan represented by the budget and reports to the Board at least four times a year.

Investments

The Company owns listed shares as set out below, which are valued at the closing price on the TSX at June 30, 2015.

	Holding	Number of Shares	Exchange	Closing Price Jun. 30, 2015	Value at Jun. 30, 2015
Chinook Energy Inc.	Common Shares	1,000,000	TSX	$ 0.94	$ 940

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 have been no further sales of Chinook common shares.

Capital Expenditures

For the quarter to June 30, 2015, the Company's capital expenditures totaled $8.9 million (2014 - $33.6 million), all of which was spent expanding field facilities and building pipelines at Umbach. No wells were drilled or completed during the quarter.

In the first half of 2015, the Company drilled six 100% working interest horizontal wells, completed two horizontal wells and one salt water disposal well, tied in four horizontal wells and completed an expansion of a compressor station at Umbach which added compression capacity of 27 Mmcf per day. A 15-kilometre pipeline was built to a third party natural gas processing plant. Major field capital outlays in the first half of 2015 include $19.3 million on drilling and completions and $23.6 million on facilities, equipping and tie-ins, all in the Umbach area.

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Land and lease	$ 184	$ 636	$ 520	$ 854
Drilling	120	14,409	12,373	26,736
Completions	79	12,009	6,966	17,476
Facilities and pipelines	8,254	5,847	23,632	9,356
Recompletions and workovers	226	757	1,032	1,502
Proceeds on disposition of oil and gas properties	-	-	-	-
Property and facility acquisitions	-	(40)	-	88,054
Property acquisition, adjustments, and administrative assets	1	21	21	56
Total	$ 8,864	$ 33,639	$ 44,544	$ 144,034

Capital expenditures in the reporting periods were allocated as follows:

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Exploration and evaluation	$ 184	$ 813	$ 500	$ 80,340
Property and equipment	8,680	32,826	44,044	63,694
Total – net of dispositions	$ 8,864	$ 33,639	$ 44,544	$ 144,034

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 June 30, 2015 corresponds to the active field program at Umbach.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. Changes in the amount of the liability during the six months ended June 30, 2015 reflect (i) additional liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, iii) changes in the amount of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.3%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation including monitoring actual abandonment and reclamation costs which is also supported by external information from industry sources and has regard to industry best practices, provincial and other regulation and evolution of same. Under IFRS, the amount of the decommissioning liability associated with the Alberta properties sold subsequent to the end of the reporting period is carried as a current liability.

Shareholders' Equity

Details of share issuances from inception to June 30, 2015 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds(1) ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended Dec.31/14	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Six months ended Jun.30, 2015	Stock option exercises	33	$ 1.83	60
				36,460
Total at June 30, 2015		119,355	$ 3.28	$ 391,714

(1) Before share issue costs.

On January 31, 2014, the Company issued 13,629,442 common shares at a fair value under IFRS of $4.25 per share, as partial consideration for the acquisition of two 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 June 2015, the Company issued 8,000,000 common shares pursuant to a bought deal financing at a price of $4.55 per common share for gross proceeds of $36,400,000. This financing closed on June 10, 2015. Net proceeds received totaled $34.2 million.

During the first six months of 2015, stock options were exercised at an average price of $1.83 per optioned share and 33,000 common shares were issued for proceeds of $60,000.

Issued and outstanding common shares at June 30, 2015 and August 13, 2015, the date of this MD&A, totaled 119,354,978.

CONTRACTUAL OBLIGATIONS

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

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

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, not including operating costs, totaling approximately $3.0 million over the term of the lease. Current monthly operating costs amount to $28,300. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $135.6 million over the next five years.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 30, 2015 appears below:

	2015					2014		2013
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production revenue ($000s)(1)	20,236	25,871	28,556	24,131	20,202	19,393	15,420	13,093
Non-GAAP funds from operations ($000s)(2)	8,170	13,712	13,892	11,784	11,076	8,660	7,501	6,144
Per share								
- basic ($)	0.07	0.12	0.13	0.11	0.10	0.09	0.09	0.08
- diluted ($)	0.07	0.12	0.12	0.11	0.10	0.08	0.09	0.08
Net income (loss) ($000s)	(4,191)	(3,565)	(7,422)	5,473	6,598	206	(25,174)	(1,429)
Per share								
- basic ($)	(0.04)	(0.03)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)
- diluted ($)	(0.04)	(0.03)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)
Net capital expenditures ($000s)	8,864	35,680	20,095	30,426	33,640	110,394	11,380	23,717
Average daily production - Boe	9,657	9,776	10,173	7,160	5,462	5,068	4,773	3,800
Net debt ($000s)(3)	28,051	85,098	63,080	56,157	41,837	22,176	12,059	40,968

(1) Includes realized hedging gains and losses.
(2) See Non-GAAP Measurements on page 10 of this MD&A.
(3) Includes investments and working capital deficiency and excludes the fair value of commodity price contracts.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the period ended June 30, 2015 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations using information which may involve an element of measurement uncertainty. Variations between amounts estimated and included in the financial statements and actual results subsequently realized could have a material effect on Storm's operating results and financial position.

Accounting for Acquisitions

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

Accounts Payable and Accrued Liabilities

At the end of each reporting period, the Company estimates the cost of services and materials provided during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes the cost of such unbilled services and materials using well established measurement procedures. Nonetheless, such procedures may reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced relate in large part to the Company's capital programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity, the amount subject to estimation may be a large part of the total obligation.

Decommissioning Liability

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

Income Taxes

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

Share-Based Compensation

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

Exploration and Evaluation Assets

Costs incurred by the Company in the initial assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences, or are expensed if the Company determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. 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 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, the carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount and adjustments to the carrying amount may be made. 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, 2015 for the year ended December 31, 2014 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2014 under the heading "Risk Assessment".

FINANCIAL REPORTING UPDATE

Accounting Changes

Future Accounting Policies

Financial Instruments

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

Revenue

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

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

ADDITIONAL INFORMATION

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

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	June 30, 2015	December 31, 2014
ASSETS		
Current		
Accounts receivable (Note 11)	$ 3,550	$ 8,205
Prepaids and deposits	705	905
Investments (Note 3)	940	1,270
Assets held for sale (Note 14)	33,826	-
Fair value of commodity price contracts (Note 11)	5,184	12,920
	44,205	23,300
Exploration and evaluation (Note 4)	124,183	126,805
Property and equipment (Note 5)	263,541	268,463
	$ 431,929	$ 418,568
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 11,556	$ 27,430
Decommissioning liability on assets held for sale (Note 14)	10,113	-
	21,669	27,430
Bank indebtedness (Note 6)	45,403	46,030
Decommissioning liability (Note 7)	15,091	23,553
	82,163	97,013
Shareholders' equity		
Share capital (Note 8)	385,489	351,161
Contributed surplus (Note 9)	5,112	3,363
Deficit	(40,835)	(33,079)
Accumulated other comprehensive income	-	110
	349,766	321,555
Commitments (Note 13)		
	$ 431,929	$ 418,568

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 June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Revenue				
Revenue from product sales	$ 18,461	$ 21,701	$ 36,972	$ 42,508
Royalties	(1,426)	(2,304)	(1,899)	(5,753)
	$ 17,035	$ 19,397	$ 35,073	$ 36,755
Realized gain (loss) on commodity price contracts (Note 11)	1,775	(1,499)	9,135	(2,913)
Unrealized gain (loss) on commodity price contracts (Note 11)	(899)	1,552	(7,736)	(1,385)
	876	53	1,399	(4,298)
Expenses				
Production	7,523	4,676	15,147	9,638
Transportation	1,023	909	2,499	1,691
General and administrative	1,329	758	3,298	2,085
Share-based compensation (Note 9)	783	568	1,768	825
Depletion and depreciation (Note 5)	8,678	6,065	17,897	11,764
Exploration and evaluation costs expensed (Note 4)	-	116	103	268
Accretion	137	83	270	150
	19,473	13,175	40,982	26,421
Income (loss) before the following:	(1,562)	6,275	(4,510)	6,036
Interest and finance costs	(765)	(479)	(1,382)	(692)
Gain on disposal of investments (Note 3)	-	1,195	-	1,486
Unrealized loss on investments (Note 3)	(220)	(380)	(220)	-
Loss on assets held for sale (Note 14)	(1,644)	-	(1,644)	-
Loss on sale of oil and gas properties (Note 3)	-	(13)	-	(26)
Net income (loss) for the period	(4,191)	6,598	(7,756)	6,804
Other comprehensive income (loss)				
Reversal of prior period unrealized (gain) loss on investments (Note 3)	(60)	1,060	(110)	1,060
Comprehensive income (loss) for the period	$ (4,251)	$ 7,658	$ (7,866)	$ 7,864
Net income (loss) per share (Note 10)				
- basic	$ (0.04)	$ 0.06	$ (0.07)	$ 0.06
- diluted	$ (0.04)	$ 0.06	$ (0.07)	$ 0.06

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)					Six Months to June 30, 2015
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$ 351,161	$ 3,363	$(33,079)	$ 110	$ 321,555
Net loss for the period	-	-	(7,756)	-	(7,756)
Issue of common shares (Note 8)	36,460	-	-	-	36,460
Share issue costs (Note 8)	(2,151)	-	-	-	(2,151)
Share-based compensation (Note 9)	-	1,768	-	-	1,768
Share based compensation on options exercised (Note 8)	19	(19)	-	-	-
Reversal of prior period unrealized gain on investments (Note 3)	-	-	-	(110)	(110)
Balance, end of period	$ 385,489	$ 5,112	$(40,835)	$ -	$ 349,766

(Canadian $000s) (unaudited)					Six Months to June 30, 2014
	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$ 252,837	$ 2,969	$(37,934)	$ -	$ 217,872
Net income for the period	-	-	6,804	-	6,804
Issue of common shares (Note 9)	93,802	-	-	-	93,802
Share issue costs (Note 9)	(1,829)	-	-	-	(1,829)
Share-based compensation (Note 10)	-	825	-	-	825
Share-based compensation on options exercised (Note 10)	323	(323)	-	-	-
Reversal of prior period unrealized loss on investments (Note 3)	-	-	-	1,060	1,060
Balance, end of period	$ 345,133	$ 3,471	$(31,130)	$ 1,060	$ 318,534

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Operating activities				
Net income (loss) for the period	$ (4,191)	$ 6,598	$ (7,756)	$ 6,804
Non-cash items:				
Share-based compensation (Note 9)	783	568	1,768	825
Depletion, depreciation and accretion (Note 5)	8,815	6,148	18,167	11,914
Exploration and evaluation costs expensed (Note 4)	-	116	103	268
Gain on disposal of investments (Note 3)	-	(1,195)	-	(1,486)
Unrealized loss on investments (Note 3)	220	380	220	-
Loss on assets held for sale	1,644	-	1,644	-
Loss on sale of oil and gas properties	-	13	-	26
Unrealized loss (gain) on commodity price contracts (Note 11)	899	(1,552)	7,736	1,385
	8,170	11,076	21,882	19,736
Net change in non-cash working capital items (Note 12)	622	1,274	847	419
	8,792	12,350	22,729	20,155
Financing activities				
Proceeds from issue of common shares - net of expenses (Note 8)	34,309	1,027	34,309	34,048
Increase (decrease) in bank indebtedness	(18,344)	13,206	(627)	7,853
	15,965	14,233	33,682	41,901
Investing activities				
Additions to exploration and evaluation assets (Note 4)	(184)	(788)	(500)	(1,389)
Additions to property and equipment (Note 5)	(8,680)	(32,814)	(44,044)	(54,591)
Cash portion of acquisitions of property and equipment and exploration and evaluation assets (Notes 4 and 5)	-	(38)	-	(30,129)
Proceeds on disposal of investments (Note 3)	-	2,355	-	3,806
Net change in non-cash working capital items (Note 12)	(15,893)	4,702	(11,867)	20,247
	(24,757)	(26,583)	(56,411)	(62,056)
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 six months ended June 30, 2015 and 2014

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"). The financial statements follow the same accounting policies and methods of computation as used in the audited consolidated financial statements for the years ended December 31, 2014 and 2013. The 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, 2014 and 2013.

These financial statements were authorized for issue by the Board of Directors on August 13, 2015.

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 11.

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.

Judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 3 to the Company's audited consolidated financial satements for the year ended December 31, 2014.

3. INVESTMENTS

	June 30, 2015	December 31, 2014
Chinook Energy Inc. ("Chinook")	$ 940	$ 1,270

The investment in Chinook was transferred to Storm from a predecessor company in August 2010 and at June 30, 2015 the Company held a total of 1.0 million common shares (December 31, 2014 – 1.0 million). Chinook is listed on the TSX.

The reversal of unrealized revaluation gains in the amount of $60,000 and $110,000, respectively, for the three and six months ended June 30, 2015, was recognized in other comprehensive income. In the same periods of 2014, the reversal of an unrealized revaluation loss of $1.1 million was also recognized in other comprehensive income. Further erosion of the Chinook share price resulted in an unrealized loss of $220,000 for the three and six months ended June 30, 2015, recognized on the consolidated statement of loss.

In 2014, the Company sold 2.0 million common shares of Chinook for net proceeds of $3.8 million and recognized a gain of $1.5 million for the six months ended June 30, 2015 which was recognized in the consolidated statement of income.

4. EXPLORATION AND EVALUATION

	Six Months Ended June 30, 2015	Year ended December 31, 2014
Balance, beginning of period	$ 126,805	$ 87,396
Acquisitions	-	78,930
Additions	500	1,754
Exploration and evaluation expenditures expensed	(103)	(1,427)
Future decommissioning costs	338	3,476
Transfer to assets held for sale	(2,840)	-
Transfer to property and equipment	(517)	(43,324)
Balance, end of period	$ 124,183	$ 126,805

5. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2015	Year ended December 31, 2014
Net book value, beginning of period	$ 268,463	$ 152,472
Cost		
Balance, beginning of period	$ 379,207	$ 211,024
Acquisitions	-	8,972
Additions	44,044	104,850
Future decommissioning costs	1,044	11,037
Transfer to assets held for sale	(91,094)	-
Transfer from exploration and evaluation assets	517	43,324
Balance, end of period	$ 333,718	$ 379,207
Accumulated depletion and depreciation		
Balance, beginning of period	$ (110,744)	$ (58,552)
Depletion and depreciation	(17,897)	(29,492)
Transfer to assets held for sale	58,464	-
Reduction in carrying amount of property and equipment		(22,700)
Balance, end of period	$ (70,177)	$ (110,744)
Net book value, end of period	$ 263,541	$ 268,463

6. BANK INDEBTEDNESS

As at June 30, 2015, the Company had an extendible revolving bank facility in the amount of $150.0 million (December 31, 2014 – $130.0 million) based on the Company's producing reserves. In July 2015, the facility was decreased to $140.0 million in conjunction with the disposal of certain non-core oil and gas properties (see Note 14). The revolving facility is available to the Company until April 29, 2016. At that time the Company has the option to extend the facility for an additional year. At June 30, 2015, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that net debt including working capital deficiency not exceed the facility amount. The facility is subject to mid-year review by the Company's banking syndicate in October 2015.

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 the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's continuing decommissioning obligation is approximately $24.6 million (December 31, 2014 - $37.3 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 2.3% (2014 – 2.2%) and an inflation rate of 2.0% (2014 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $15.1 million. In connection with the sale of certain non-core oil and gas properties (see Note 14), $10.1 million of decommissioning liabilities has been classified as a current liability.

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

	Six Months Ended June 30, 2015	Year Ended December 31, 2014
Balance, beginning of period	$ 23,553	$ 8,689
Obligations incurred	987	3,797
Obligations acquired	-	710
Obligations disposed	(4)	-
Obligations transferred to liabilities held for sale	(10,113)	-
Obligations settled	-	(34)
Change in rate estimate	-	6,029
Change in cost estimates	398	4,011
Accretion expense	270	351
Balance, end of period	$ 15,091	$ 23,553

8. SHARE CAPITAL

Authorized

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

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2013	87,483	$ 252,837
Shares issued pursuant to Umbach acquisition(1)	13,629	57,925
Shares issued pursuant to private placement(2)	8,500	34,850
Share issue costs(2)	-	(1,829)
Shares issued on stock option exercises(3)	1,710	7,378
Balance as at December 31, 2014	111,322	$ 351,161
Shares issued pursuant to private placement(4)	8,000	36,400
Share issue costs(4)	-	(2,151)
Shares issued on stock option exercises (5)	33	79
Balance as at June 30, 2015	119,355	$ 385,489

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

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

(3) During 2014, 1,709,666 common shares were issued upon the exercise of a like amount of stock options for proceeds of approximately $5.5 million. Related prior period share-based compensation of $1.8 million was transferred to share capital from contributed surplus. Of this amount, $0.3 million applied to the six months ended June 30, 2014.

(4) On June 10, 2015 the Company issued 8,000,000 common shares, pursuant to a bought deal financing, at a price of $4.55 per common share for gross proceeds of $36,400,000 before issue costs of approximately $2.2 million.

(5) During the first six months of 2015, 33,000 common shares were issued upon the exercise of stock options for proceeds of $60,000 and related prior period share-based compensation of $19,000 was transferred to share capital from contributed surplus.

9. 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 tranches of one third over three years. Under the stock option plan, a total of 11,935,497 common shares are available for issuance. At June 30, 2015, and at the date of this quarterly report, options in respect of 5,923,834 common shares had been issued, all of which are unexercised, and options remain in respect of 6,011,663 common shares which are available for further grants under the stock option plan.

Details of the options outstanding at June 30, 2015 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2013	3,897	$ 2.47
Granted during the period	3,770	$ 4.52
Exercised during the period	(1,710)	$ 3.26
Outstanding at December 31, 2014	5,957	$ 3.54
Exercised during the period	(33)	$ 1.83
Outstanding at June 30, 2015	5,924	$ 3.55
Number exercisable at June 30, 2015	2,270	$ 2.64

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	2,114	1.4	$ 1.83	1,619	$ 1.85
$2.64 - $3.95	40	0.7	$ 3.04	40	$ 3.04
$3.96 - $4.68	3,770	3.1	$ 4.52	611	$ 4.70
Total	5,924	2.5	$ 3.55	2,270	$ 2.64

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).

No options have been granted to date in 2015. The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the 1.8 million options granted during the six months ended June 30, 2014 of $1.99 per share include the following:

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

Share-based compensation expense of $783,000 and $1,768,000 was charged to the consolidated statement of income (loss) during the three and six months to June 30, 2015 (2014 - $568,000 and $825,000) with an equivalent offset to contributed surplus. Volatility is based on the historical price variances of the Company's share price using market data.

10. NET INCOME (LOSS) PER SHARE

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

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Net income for the period	$ (4,191)	$ 6,598	$ (7,756)	$ 6,804
Weighted average number of common shares outstanding – basic:				
Common shares outstanding at beginning of period	111,322	100,668	111,322	87,483
Effect of shares issued	1,768	9,174	889	17,797
Weighted average number of common shares outstanding – basic	113,090	109,842	112,211	105,280
Effect of outstanding options	-	2,156	-	1,917
Weighted average number of common shares outstanding - diluted	113,090	111,998	112,211	107,197
Net income (loss) per share				
- basic	$ (0.04)	$ 0.06	$ (0.07)	$ 0.06
- diluted	$ (0.04)	$ 0.06	$ (0.07)	$ 0.06

At June 30, 2015, all outstanding stock options were considered anti-dilutive as the Company was in a loss position. In the first half of 2014, 15,000 stock options were excluded from the diluted-per-share calculation.

11. FINANCIAL INSTRUMENTS

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 June 30, 2015 fair value of $0.9 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 June 30, 2015 is as follows:

	Carrying Amount as at June 30, 2015
Accounts receivable	$ 3,550
Fair value of commodity price contracts	5,184
Total	$ 8,734

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, they are subject to the limitations established by the Board of Directors and the Company's banking agreement.

Accounts receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. The Company's production is sold to organizations whose credit worthiness is assessable from publicly available information. The Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. The Company does not typically obtain collateral security from joint venture partners.

No default on outstanding receivables is anticipated and no part of the Company's outstanding receivable balance is considered past due at June 30, 2015.

Market risk

Commodity Prices

As at June 30, 2015, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts of $5,184,000 (December 31, 2014 – $12,920,000) is included in current assets. This resulted in unrealized mark-to-market losses of $899,000 (2014 – gain of $1,552,000) and $7,736,000 (2014 – loss of $1,385,000) when measured against the fair market value at the preceding period end, which is recognized in the consolidated statement of income (loss) for the three and six months ended June 30, 2015. In January 2015, the Company terminated all of its crude oil contracts in exchange for $5.1 million which is included as a realized gain in the calculation of net income for the three and six months ended March 31 and June 30, 2015.

	WTI Crude Oil		AECO Natural Gas	
	Volume	Average Price (Cdn$/Bbl)	Volume	Average Price (Cdn$/GJ)
Fixed Price				
Q3 – 2015			34,000 GJ/day	$3.27
Q4 – 2015			30,000 GJ/day	$3.47
Jan – Dec 2016	500 Bbls/day	$ 77.25	15,000 GJ/day	$3.00
Q1 – 2016			5,000 GJ/day	$3.06
Jan – Dec 2016			15,000 GJ/day	$3.00
Jan – Dec 2016			11,000 GJ/day	AECO - Stn 2 diff ($0.3375)/GJ

During the three and six months ended June 30, 2015, the Company realized gains from commodity price contracts in place or terminated in the amount of $1,775,000 and $9,135,000, respectively (2014 – losses of $1,499,000 and $2,913,000, respectively).

Sensitivities

Using the Company's actual production volumes, royalty rates and debt levels for the first six months of 2015, the estimated after-tax effect that changes in certain factors would have on net income and net income per share is set out below:

	2015	
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI	$ 360,000	-
$0.10/Mcf change in the price of natural gas	$ 850,000	$0.01
1% change in the interest rate	$ 550,000	-

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.

12. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to June 30, 2015	Three Months to June 30, 2014	Six Months to June 30, 2015	Six Months to June 30, 2014
Accounts receivable	$ 5,944	$ 473	$ 4,655	$ (1,808)
Prepaids and deposits	2,431	(2,574)	200	(2,341)
Accounts payable and accrued liabilities	(23,645)	8,077	(15,874)	24,815
Change in non-cash working capital	$ (15,270)	$ 5,976	$ (11,019)	$ 20,666
Relating to:				
Operating activities	$ 623	$ 1,274	$ 848	$ 419
Investing activities	(15,893)	4,702	(11,867)	20,247
	$ (15,270)	$ 5,976	$ (11,019)	$ 20,666
Interest paid during the period	$ 679	$ 160	$ 1,198	$ 370
Income taxes paid during the period	$ -	$ -	$ -	$ -

13. COMMITMENTS

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

	2015	2016	2017	2018	2019
Office lease	$ 466	$ 940	$ 940	$ 705	$ -
Gas transportation and processing commitments	9,502	40,123	37,457	31,389	17,100
Total	$ 9,968	$ 41,063	$ 38,397	$ 32,094	$ 17,100

In the first half of 2015, office lease payments of $462,000 (2014 - $456,000) were included in general and administrative expense.

14. SUBSEQUENT EVENTS

During the second quarter of 2015 the Company initiated the sale of its Grande Prairie properties. The disposition of these assets closed on July 15, 2015 for proceeds of $24.0 million before closing adjustments. The net carrying value of $23.7 million is recorded in assets and liabilities held for sale on the Statement of Financial Positon at June 30, 2015. The resulting loss of $1.6 million has been recorded on the Statement of Loss and Comprehensive Loss for the three and six months ending June 30, 2015. For the three and six months ending June 30, 2015, these properties generated net field operating income of $0.9 million and $1.5 million, respectively. In conjunction with the closing of the asset sale, the Company's bank credit facility was reduced from $150.0 million to $140.0 million.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Donald G. McLean
Chief Financial Officer

John Devlin
Vice President, Finance

Jamie Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

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Stock Exchange Listing

TSX Venture Exchange
Trading Symbol “SRX”

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Bank of Montreal
Royal Bank of Canada
Calgary, Alberta

Executive Offices

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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
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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