STORM RESOURCES

Q2 - 2017 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
FINANCIAL				
Revenue from product sales(1)	27,317	13,870	64,362	29,992
Funds flow	11,629	5,781	29,587	13,636
Per share – basic and diluted ($)	0.10	0.05	0.24	0.11
Net income (loss)	9,752	(20,493)	30,383	(25,477)
Per share – basic and diluted ($)	0.08	(0.17)	0.25	(0.21)
Operations capital expenditures(2)	4,307	613	31,664	24,559
Debt including working capital deficiency(2)(3)	90,582	71,254	90,582	71,254
Common shares (000s)				
Weighted average - basic	121,557	119,929	121,500	119,761
Weighted average - diluted	121,682	119,929	121,702	119,761
Outstanding end of period – basic	121,557	120,179	121,557	120,179
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	21.45	11.86	23.00	12.55
Royalties	(1.47)	(0.19)	(1.69)	(0.48)
Production	(6.74)	(6.76)	(6.25)	(6.73)
Transportation	(1.08)	(0.33)	(0.86)	(0.43)
Field operating netback(2)	12.16	4.58	14.20	4.91
Realized (loss) gain on hedging	(1.10)	2.24	(1.76)	2.64
General and administrative	(1.17)	(1.19)	(1.13)	(1.22)
Interest and finance costs	(0.76)	(0.68)	(0.73)	(0.62)
Funds flow per Boe	9.13	4.95	10.58	5.71
Barrels of oil equivalent per day (6:1)	13,991	12,852	15,461	13,135
Natural gas production				
Thousand cubic feet per day	68,308	63,800	76,157	64,906
Price (Cdn$ per Mcf)(1)	2.81	1.28	3.04	1.45
Condensate production				
Barrels per day	1,468	1,172	1,612	1,312
Price (Cdn$ per barrel)(1)	57.65	50.05	61.31	45.34
NGL production				
Barrels per day	1,138	1,047	1,156	1,006
Price (Cdn$ per barrel)(1)	20.45	11.63	21.78	11.06
Wells drilled (100% working interest)	-	-	6.0	7.0
Wells completed (100% working interest)	-	-	4.0	2.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements, including field operating netback, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 25 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2017 SECOND OUARTER HIGHLIGHTS

- Production averaged 13,991 Boe per day, a per-share increase of 8% from the second quarter of last year. The year-over-year increase was achieved in spite of approximately 80% of production being shut in for 25 days in June for a planned maintenance turnaround at the McMahon Gas Plant (April and May averaged 18,306 Boe per day).

- Condensate and NGL production totaled 2,606 barrels per day which was 19% of total production and represented 36% of total revenue.

- At the end of the quarter, there was an inventory of nine Montney horizontal wells (9.0 net) at Umbach that had not started producing which includes one completed well. One horizontal well (1.0 net) started production in the quarter and six horizontal wells (6.0 net) started production in the first half of the year.

- To date in 2017, four Montney horizontal wells (4.0 net) have been completed and the three with enough production history have averaged 4.8 Mmcf per day gross raw gas plus 175 barrels per day of field condensate, or 960 Boe per day sales, over the first 90 calendar days (only 75 producing days as a result of the McMahon Gas Plant turnaround). These wells are approximately 25% longer than wells completed during 2014 to 2016 and are further south in the oil window which increases the field condensate rate (115% higher than the average from all of Storm's wells at Umbach).

- Controllable cash costs (production, general and administrative, interest and finance) were $8.67 per Boe which is an increase from $7.65 per Boe in the prior quarter. The increase is primarily due to production being reduced by the scheduled maintenance turnaround at the McMahon Gas Plant which increased production costs by $0.90 per Boe. Costs are expected to resume trending lower in the second half of 2017.

- Funds flow was $11.6 million ($9.13 per Boe), an increase of 100% from a year ago. The increase was driven by an 81% increase in revenue per Boe and a 9% increase in production volumes which was partially offset by a realized hedging loss of $1.4 million, or $1.10 per Boe.

- Net income was $9.8 million or $0.08 per share which includes an unrealized hedging gain of $9.5 million (mark to market non-cash gain). Hedging continues to have a significant recurring impact on quarterly earnings. Excluding the unrealized and realized hedging gains or losses, net income would be $1.7 million, or $0.01 per share.

- Capital investment was $4.3 million with most of this being invested in infrastructure at Umbach (pipelined and equipped a second water disposal well and added a second fuel gas conditioning unit). This was less than the original forecast of $13 to $18 million as the planned completions of four to six wells were delayed by spring road bans being extended into mid-July.

- Debt including working capital deficiency was reduced to $90.6 million from $97.9 million at the end of the prior quarter. This is 1.9 times annualized second quarter funds flow, an increase from 1.4 times at the end of the previous quarter as a result of production and funds flow being reduced by the McMahon Gas Plant turnaround. The bank credit facility is $165 million.

- Commodity price hedges continue to be added and currently protect approximately 45% of forecast production for the second half of 2017.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 109,000 net acres (155 net sections). To date, Storm has drilled 59 horizontal wells (55.4 net).

Production in the second quarter was 13,703 Boe per day and liquids recovery was 39 barrels per Mmcf sales with 56% being higher priced condensate.

Activity in the second quarter included pipelining and equipping a second water disposal well and adding a second fuel gas conditioning unit which is required for the future expansion of the third field compression facility. One horizontal well (1.0 net) started production. At the end of the quarter, there was an inventory of nine horizontal wells (9.0 net) that had not started producing which included one completed well.

There are three field compression facilities with current capacity totaling 115 Mmcf per day raw gas and throughput in the second quarter averaged 69 Mmcf per day raw gas (92 Mmcf per day in April and May). Capacity at the third facility can be increased by 35 Mmcf per day by adding a second compressor for $7 million. Delivery of the second compressor is scheduled for the fourth quarter of 2017 with installation planned for the first half of 2018, possibly as early as January depending on commodity prices and well results. This increases total field compression to 150 Mmcf per day and supports growth in corporate production to approximately 27,000 Boe per day.

Storm's produced natural gas is sour (approximately 1.2% H_2S) and is directed to the McMahon and Stoddart Gas Plants where firm processing commitments total 80 Mmcf per day raw gas for the second half of 2017. At the McMahon Gas Plant, a new processing arrangement began in January 2017 and has a commitment totaling 65 Mmcf per day of raw gas for 5 to 15 years. The arrangement reduced corporate production costs by approximately 15%, supports future growth with an option to add up to 35 Mmcf per day, and provides access to three sales pipelines. Most importantly, the arrangement will result in accelerated corporate growth as more capital can be directed to drilling and completing horizontal wells which offer a higher rate of return than building a sour gas plant.

A summary of horizontal well performance and costs is provided below. Calendar day rates for the 2016 and 2017 horizontal wells were reduced by the McMahon Gas Plant turnaround from June 5 to July 14. For example, the three 2017 wells produced for an average of 75 days out of the first 90 calendar days. Future horizontal wells will have completed lengths of 1,700 to 2,100 metres with 30 to 36 frac stages and the increased length is expected to improve production rates.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP90 Cal Day Mmcf/d Raw	IP180 Cal Day Mmcf/d Raw	IP365 Cal Day Mmcf/d Raw
2013 6 hz's	17	1,190 m	$4.6 million $270 K/stage	3.5 Mmcf/d 6 hz's	2.9 Mmcf/d 6 hz's	2.2 Mmcf/d 6 hz's
2014 12 hz's(1)	19	1,170 m	$4.6 million $240 K/stage	4.9 Mmcf/d 12 hz's	4.4 Mmcf/d 12 hz's	3.5 Mmcf/d 12 hz's
2015 11 hz's	22	1,360 m	$4.4 million $200 K/stage	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 11 hz's
2016 10 hz's	25	1,300 m	$3.7 million $148 K/stage	5.1 Mmcf/d 10 hz's	4.2 Mmcf/d 10 hz's	3.7 Mmcf/d 2 hz's
2017 4 hz's	35	1,670 m	$4.3 million $123 K/stage	4.8 Mmcf/d(2) 3 hz's		

(1) 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).
(2) Wells produced for an average of 75 days due to the McMahon maintenance turnaround June 5 to July 14.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the Horn River Basin (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well averaged 230 Boe per day in the second quarter and cumulative production to date from this well is 5.7 Bcf raw.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth by providing some certainty regarding future revenue and funds flow. The objective is to hedge 50% of most recent quarterly or monthly production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that WTI is hedged as approximately 80% of Storm's liquids production is priced in reference to WTI. The current hedge position is summarized below and approximately 45% of forecast production for the second half of 2017 is currently hedged.

Q3 – Q4 2017		
Crude Oil	1,200 Bopd	WTI Cdn$65.19/Bbl floor, Cdn$69.90/Bbl ceiling
Natural Gas	38,000 GJ/d (30,400 Mcf/d)	AECO Cdn$2.70/GJ ($3.37/Mcf)
	12,800 Mmbtu/d (10,800 Mcf/d)	Chicago Cdn$4.17/Mmbtu ($4.94/Mcf)(1)
2018		
Crude Oil	512 Bopd	WTI Cdn$66.45/Bbl floor, Cdn$70.11/Bbl ceiling
Natural Gas	750 GJ/d (600 Mcf/d)	AECO Cdn$2.80/GJ ($3.50/Mcf)
	18,425 Mmbtu/d (15,600 Mcf/d)	Chicago Cdn$4.01/Mmbtu ($4.75/Mcf)(1)
	2,000 Mmbtu/d (1,700 Mcf/d)	Chicago US$2.98/Mmbtu

(1) Hedge price in Chicago does not include the Alliance Pipeline tariff to Chicago which is approximately Cdn$1.35 per GJ including the cost of fuel.

The Company also has natural gas price differential hedges in place (Chicago – AECO and AECO – Station 2) with details provided in the notes to the condensed interim consolidated financial statements.

Firm transportation commitments are used to diversify sales points and mitigate pricing risk. Firm transportation totals 72 Mmcf per day in 2017 and increases to 102 Mmcf per day in 2018. In addition, preferential interruptible capacity on the Alliance Pipeline adds up to 14 Mmcf per day in 2017 and up to 15 Mmcf per day in 2018. Natural gas production exceeding firm commitments is directed to Chicago and/or Station 2 using interruptible pipeline capacity (sales point depends on price). Note that Storm's natural gas marketing arrangements result in the cost of transportation on the Alliance Pipeline being deducted from revenue ($5.7 million deducted in the second quarter of 2017). Further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

2017	2018
Alliance Pipeline(1) 51 Mmcf/d Chicago price 5 Mmcf/d ATP price	Alliance Pipeline(1) 55 Mmcf/d Chicago price 5 Mmcf/d ATP price
Enbridge T-North 16 Mmcf/d Station 2 price	Enbridge T-North 29 Mmcf/d Station 2 price
	Enbridge T-North & TCPL NGTL 13 Mmcf/d AECO price

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

OUTLOOK

For the third quarter of 2017, production is anticipated to be 15,500 to 17,000 Boe per day which includes the effect of the maintenance turnaround at the McMahon Gas Plant from June 5 to July 14. Approximately 80% of production was shut in for 14 days in the third quarter. The duration of the turnaround was 39 days which was longer than the original expectation of 21 days. Capital investment in the third quarter is expected to be $28 million and includes drilling four horizontal wells plus completing six horizontal wells at Umbach.

The third quarter has seen Western Canadian natural gas prices weaken as a result of continued production growth and maintenance restrictions on the TCPL NGTL system and the Enbridge T-South pipeline. To date in the third quarter, AECO daily has averaged $1.59 per GJ (versus $2.64 per GJ in the second quarter) while Station 2 daily has averaged $1.06 per GJ (versus $2.21 per GJ in the second quarter). The weakness is likely to continue until September for AECO and October for Station 2 when the maintenance restrictions are expected to end. Based on field estimates, Storm's production in July was 12,200 Boe per day and to date in August has averaged 17,300 Boe per day. Until the Station 2 price improves, production will not be increased and volumes sold at Station 2 will be minimized to meet firm transportation commitments. Approximately 20% of current natural gas sales are at Station 2.

Updated guidance for 2017 is summarized below. Operations capital is forecast to be $75 to $95 million (previously $75 to $80 million) depending on both well results and commodity prices meeting Storm's forecast for the second half of 2017. Capital investment at the high end of the range ($95 million) would accelerate growth in 2018 by drilling and completing additional wells in the fourth quarter of 2017 (minimal impact on forecast production for 2017). This includes installing a second compressor at the third Umbach facility in January 2018. Should commodity prices be lower than forecast, capital investment would be reduced to the low end of the range ($75 million) by deferring the additional activity. Forecast commodity prices reflect actual year-to-date pricing plus the approximate forward strip for the remainder of 2017.

2017 Guidance

	May 15, 2017	Updated August 15, 2017
$Cdn/$US exchange rate	0.75	0.775
Chicago daily natural gas (US$/Mmbtu)	$3.00	$2.90
AECO daily natural gas (Cdn$/GJ)	$2.50	$2.45
Station 2 daily natural gas (Cdn$/GJ)	$2.10	$2.00
Edmonton light oil (Cdn$/bbl)	$62.00	$60.00
Estimated average operating costs ($/Boe)	$5.50 - $6.00	$5.75 - $6.00
Estimated average royalty rate (% production revenue before hedging)	7% - 10%	6% - 8%
Estimated operations capital ($ million) (excluding acquisitions & dispositions)	$75.0 - $80.0	$75.0 - $95.0
Estimated cash G&A - $ million	$5.3	$6.0 - $6.5
- $/Boe	$0.85	$0.95 - $1.05
Forecast fourth quarter production (Boe/d) % condensate and NGL	19,000 - 21,000 17%	19,000 - 21,000 17%
Forecast annual production (Boe/d) % condensate and NGL	17,000 - 18,000 17%	16,500 - 18,000 17%
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	12 gross (12.0 net) 14 gross (14.0 net) 15 gross (15.0 net)	12 – 15 gross (12.0 – 15.0 net) 10 – 16 gross (10.0 – 16.0 net) 13 – 16 gross (13.0 – 16.0 net)

2017 Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	AECO Daily (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
September 7, 2016	$3.00	$2.25	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
November 15, 2016	$3.00	$2.20	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
March 2, 2017	$3.00	$2.00	$2.50	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
May 15, 2017	$3.00	$2.10	$2.50	$75.0 - $80.0	19,000 - 21,000	17,000 - 18,000
August 15, 2017	$2.90	$2.00	$2.45	$75.0 - $95.0	19,000 - 21,000	16,500 - 18,000

Capital investment assumes the cost to drill and complete a horizontal well at Umbach is $4.7 million, an increase of 27% from the actual cost in 2016 with half of the increase from adding length and frac stages and half of the increase as a result of service cost inflation.

Planned growth through 2018 is supported by forecast commodity prices as well as the expected improvement in rates, reserves, and capital efficiencies from future Montney horizontal wells at Umbach which are planned to be approximately 50% longer than the 2014 to 2016 wells. In 2017, average production is forecast to increase by approximately 30% year over year by investing $75 to $95 million which will result in year-end net debt of approximately $100 to $120 million. For 2018, assuming commodity prices are approximately equal to forecast prices for 2017, the preliminary plan is to invest $95 to $110 million for a further 30% to 40% increase in production with forecast fourth quarter production of 25,000 to 27,000 Boe per day. Growth in 2018 requires an investment of $7 million in infrastructure at Umbach to add field compression which is planned for as early as January 2018 and can also be delayed depending on commodity prices.

Although the upper end of the range for capital investment was increased to provide the option to accelerate growth in expectation of improving well results, growth will not be accelerated to the detriment of the balance sheet. Correspondingly, capital investment has been designed to be flexible and activity can be adjusted quickly in response to changes in commodity prices.

With a large liquids-rich resource in the Montney at Umbach offering multiple years of drilling inventory, the objective remains to grow net asset value for shareholders by converting the resource into production and funds flow growth on a per-share basis.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

August 15, 2017

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

Initial Production Rates - Initial production rates ("IP") provided refer to actual raw natural gas rates reported to the British Columbia government. IP rates are not necessarily indicative of long-term performance or of ultimate recovery.

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 15, 2017 for the three and six months ended June 30, 2017.

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, 2017. 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, 2017, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2016, and (iii) the press release issued by the Company on August 15, 2017, and other operating and financial information included in this report. All of these documents as well as the Company's Annual Information Form dated March 31, 2017 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

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

This MD&A is dated August 15, 2017.

See "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 24 to 26.

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, 2017, prepared in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting" using accounting policies consistent 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, 2016. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three and six month periods ended June 30, 2016.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The operational momentum achieved in the first few months of 2017 carried into the second quarter, with strong well performance leading to record production levels in April and May, averaging approximately 18,000 Boe per day, in a reasonably strong pricing environment for both Chicago and Station 2 prices. However, this came to a halt in early June as the McMahon Gas Plant was shut down for a planned turnaround, a process that was scheduled to take 21 days starting June 5 but ended up carrying on until July 14. As a result, with less than one week's production through McMahon in June, average daily production for the quarter amounted to 13,991 Boe per day, just below the low end of the previously announced guidance range of 14,000 to 15,000 Boe per day. This production level was down 17% from the average daily production achieved in the immediately preceding quarter, although was 9% higher than the comparable quarter of 2016. The Company's compression capacity puts an upper limit on corporate production at approximately 21,000 Boe per day. During the second quarter, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 19% of total production and contributed 36% to revenue in the period. The second quarter was further tarnished by road bans that were in place for the better part of the quarter which increased overall costs and limited capital investment activity in the field.

The natural gas price realized by the Company in the second quarter fell by 13% when compared to the first quarter of 2017, however, was up a remarkable 120% when compared to the same quarter of 2016. Similarly, when comparing to the same quarter in 2016, condensate and NGL prices were up 15% and 76%, respectively, with a significant recovery in propane prices the main driver for the improvement in NGL prices. Considerable volatility remains in commodity prices with a softening of Canadian natural gas prices in June, July and August as a result of numerous infrastructure outages and restrictions across British Columbia and Alberta. Crude oil prices did not fare much better with WTI off by approximately US$6.00 per barrel from April to June on concerns over the ongoing supply glut, the effect of which was exacerbated for Canadian producers due to a strengthening in the Canadian dollar and led to lower realized pricing on Storm's condensate and NGL.

At quarter end, the Company had an inventory of nine horizontal wells (9.0 net) that had not started production, including one completed well. Given the road bans, no wells were drilled or completed in the second quarter with minimal capital expenditures in the period primarily directed to facilities, equipping and pipelines. As a result, total debt, including working capital deficiency, at quarter end amounted to $90.6 million, down from $97.9 million at the end of the first quarter. Storm retains considerable financial flexibility to manage its capital expenditure program for the remainder of the year with the ability to increase or decrease capital expenditures in response to movements in commodity prices.

Storm continues to advance plans with respect to twinning of the third field compression facility and ordered the compressor during the second quarter. Twinning the third field compression facility is expected to add 35 Mmcf per day of processing capacity at a modest cost of $7 million and provide capacity to increase Storm's potential production base to approximately 27,000 Boe per day. The on-stream date for the expansion remains in the first half of 2018. Although no wells were drilled or completed in the second quarter, subsequent to the quarter end, completions began on the first of six wells that were drilled in the first quarter with plans to complete all six wells in the third quarter.

Comparison of field operating netbacks in the second quarter to the same period in the prior year and the first quarter of 2017 are less meaningful in light of the lower production volumes and correspondingly higher fixed processing costs associated with the planned turnaround at the McMahon Gas Plant in June along with additional transportation costs incurred as a result of road bans during the period. Nevertheless, compared to the same period in 2016, the field operating netback per Boe in the second quarter of 2017 increased by 166%, primarily due to the material recovery in commodity prices. Compared to the first quarter of 2017, the field operating netback per Boe fell 23% from a combination of lower production volumes, lower commodity prices and higher costs due to the turnaround and road bans. The effect of higher prices relative to the same period in 2016 resulted in a realized hedging loss of $1.4 million during the second quarter of 2017 versus a realized hedging gain of $2.6 million in the second quarter of 2016 which reduced the aforementioned increase in the field operating netback.

During the quarter, the Company's credit facility was increased by $35 million to $165 million, an increase of 27%. The credit facility is predominantly based on the banking syndicate's assessment of the value of the Company's proved developed producing ("PDP") reserves as collateral. The credit facility increase was consistent with the increase in 2016 year-end PDP reserves, which grew by 22% year over year, while the net present value of PDP reserves (before tax, discounted at 10%) increased by 49% based on InSite Petroleum Consultants Ltd. December 31, 2016 commodity price forecast. No additional covenants were required and the interest rate structure was unchanged. The expanded credit facility provides the Company with considerable financial flexibility to manage its capital expenditure program for the foreseeable future.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				Three Months to June 30, 2017
Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
Umbach – NE BC	66,580	1,468	1,138	13,703
Horn River Basin – NE BC	1,382	-	-	230
Grande Prairie – AB	346	-	-	58
Total	68,308	1,468	1,138	13,991

				Three Months to June 30, 2016
Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
Umbach – NE BC	63,772	1,172	1,047	12,847
Horn River Basin – NE BC[3]	-	-	-	-
Grande Prairie – AB	28	-	-	5
Total	63,800	1,172	1,047	12,852

Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
				Six Months to June 30, 2017
Umbach – NE BC	74,199	1,611	1,156	15,134
Horn River Basin – NE BC[3]	1,596	-	-	266
Grande Prairie – AB	362	1	-	61
Total	76,157	1,612	1,156	15,461

Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
				Six Months to June 30, 2016
Umbach – NE BC	64,833	1,312	1,006	13,123
Horn River Basin – NE BC[3]	-	-	-	-
Grande Prairie – AB	73	-	-	12
Total	64,906	1,312	1,006	13,135

(1) Includes field condensate and plant pentanes.
(2) Includes butane and propane.
(3) Production shut in during the period due to pricing.

In the second quarter of 2017, average Boe-per-day volumes increased by 9% when compared to the second quarter of 2016 and decreased by 17% when compared to the immediately preceding quarter. For the six month period ended June 30, 2017, average Boe-per-day volumes increased by 18% year over year. Production increases for natural gas, condensate and NGL, when compared to both periods in 2016, came from growth at Umbach where the Company started production from one new 100% working interest well during the quarter and six new 100% working interest wells during the six months ended June 30, 2017. The Company had production from a total of 51 wells (47.4 net) at the end of the second quarter, an increase of 12 wells year over year. During the quarter, approximately 4,000 to 4,500 Boe per day of production was lost as a result of the planned turnaround at the McMahon Gas Plant. Production to date in the third quarter of 2017, including 14 days of downtime related to the extended turnaround at the McMahon Gas Plant, has averaged approximately 13,600 Boe per day based on field estimates.

Production in the second quarter approximated 81% natural gas, 11% condensate and 8% NGL, consistent with that achieved in the first quarter of 2017 and comparable periods in 2016.

Average Daily Production

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Natural gas (Mcf/d)	68,308	63,800	76,157	64,906
Condensate (Bbls/d)	1,468	1,172	1,612	1,312
Natural gas liquids (Bbls/d)	1,138	1,047	1,156	1,006
Total (Boe/d)	13,991	12,852	15,461	13,135

Low natural gas prices in the first six months of 2016 resulted in production being reduced to the level required to meet firm processing and transportation commitments. Improved pricing later in 2016 resulted in shut-in production being restored; this, along with acceleration of the Company's capital expenditure program, saw December 2016 monthly production increase to approximately 14,700 Boe per day from approximately 13,000 Boe per day for the first eleven months of the year. This upward trend continued through the first quarter of 2017 and into the second quarter with first quarter production averaging 16,947 Boe per day, due to the start-up of the Company's third field compression facility and, in part, illustrative of the ability of the Company's production base to respond quickly to commodity price movements. Production for April and May 2017 averaged over 18,000 Boe per day, yet averaged only 13,991 Boe per day for the second quarter of 2017 due to the effect of the turnaround at the McMahon Gas Plant in June.

Daily production per million shares outstanding at the end of the second quarter averaged 115 Boe per day, compared to 107 Boe per day for the second quarter of 2016 and 139 Boe per day for the first quarter of 2017.

Production Profile and Per-Unit Prices[(1)]

	Three Months to June 30, 2017		Three Months to June 30, 2016		Six Months to June 30, 2017		Six Months to June 30, 2016	
	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	81%	$ 2.81	83%	$ 1.28	82%	$ 3.04	82%	$ 1.45
Condensate – Bbl	11%	$ 57.65	9%	$ 50.05	10%	$ 61.31	10%	$ 45.34
Natural gas liquids – Bbl	8%	$ 20.45	8%	$ 11.63	8%	$ 21.78	8%	$ 11.06
Per Boe	100%	$ 21.45	100%	$ 11.86	100%	$ 23.00	100%	$ 12.55

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

The Company's production during the second quarter of 2017 was sold as follows:

- 40% - Adjusted Chicago monthly index price
- 33% - Station 2 daily spot price
- 22% - Adjusted Chicago daily index price
- 5% - Alliance Transfer Point (ATP)

Natural gas sold with reference to the Chicago index price is subject to a pricing reduction equal to the pipeline tariff to Chicago (approximately Cdn$1.35 per GJ) as title to the gas transfers at the natural gas processing plant in British Columbia.

A summary of reference prices for the last six quarters is set out below. Note that pricing comparability between markets is affected by foreign exchange and lack of uniformity between commodity units. Storm's realized prices also differ from market indices due to heat content of the Company's natural gas. Noteworthy is the disparity between Canadian and US index prices and the improvement in Station 2 pricing for the first six months of 2017 when compared to the first six months of 2016.

	Storm Realized Natural Gas Price (Cdn$/Mcf)	Chicago Monthly Index (US$/Mmbtu)	Chicago Daily Index (US$/Mmbtu)	AECO Daily Index (Cdn$/GJ)	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	US$/Cdn$
2017							
Q2	2.81	3.01	2.93	2.64	2.63	2.21	0.74
Q1	3.23	3.40	2.98	2.55	2.79	2.36	0.76
2016							
Q4	2.86	3.00	2.97	2.93	2.67	2.27	0.75
Q3	2.41	2.76	2.78	2.20	2.09	1.83	0.77
Q2	1.28	1.95	2.09	1.33	1.18	1.14	0.78
Q1	1.62	2.25	2.04	1.74	2.00	1.33	0.73
Average - 2016	2.05	2.49	2.47	2.05	1.98	1.64	0.75

The AECO daily index - Station 2 differential averaged -$0.41 per GJ in 2016 and averaged -$0.31 per GJ in the first six months of 2017. Station 2 pricing relative to AECO has been volatile over the last eighteen months and continued production growth from the Montney in northeast British Columbia may affect the differential as well as restrictions on the Enbridge (Spectra) and TCPL (NGTL) pipeline systems.

Storm's realized natural gas price for the second quarter of 2017 was $2.81 per Mcf. With over 60% of production sold in Chicago, Storm's basket realized price benefits from stronger Chicago pricing which is partially offset by lower Station 2 pricing.

	Storm Realized Price				
	Condensate (Cdn$/Bbl)	Natural Gas Liquids (Cdn$/Bbl)	WTI (US$/Bbl)	Edmonton Light Oil (Cdn$/Bbl)	US$/Cdn$
2017					
Q2	57.65	20.45	48.29	61.92	0.74
Q1	64.40	23.09	51.91	63.99	0.76
2016					
Q4	57.17	18.64	49.29	61.58	0.75
Q3	49.01	10.03	44.94	54.80	0.77
Q2	50.05	11.63	45.59	54.78	0.78
Q1	41.54	10.44	33.45	40.81	0.73
Average - 2016	49.34	12.51	43.32	52.99	0.75

Storm's liquids stream in the second quarter of 2017 comprised approximately 56% condensate, which is generally priced with reference to benchmark pricing for Edmonton light oil. The realized price for condensate in the second quarter of 2017 increased by 15% relative to the second quarter of 2016 and fell by 10% compared to the first quarter of 2017. The US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil was -Cdn$3.00 per barrel in the second quarter of 2017 versus -Cdn$3.97 per barrel in the second quarter of 2016. The realized price for NGL, excluding condensate, in the second quarter of 2017 increased by 76% relative to the same period in 2016. For the six month period ended June 30, 2017, the realized price for NGL, excluding condensate, increased by 97% year over year. The increase in realized NGL prices for both of the aforementioned periods was primarily due to a material recovery in propane pricing year over year.

Increasing natural gas production at Umbach has resulted in growing volumes of higher value condensate. The significance of this is illustrated by the contribution from this revenue stream, which comprised 11% of Boe production but amounted to 28% of revenue from product sales in the second quarter of 2017. Equivalent amounts for the first six months of 2017 comprised 10% of Boe production and 28% of revenue from product sales.

On a per-Boe basis, the Company's total realized price of $21.45 for the second quarter of 2017 increased by 81% and decreased by 12% when compared to the second quarter of 2016 and the first quarter 2017.

Revenue from Product Sales[(1)]

(000s)	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Natural gas	$ 17,496	$ 7,422	$ 41,913	$ 17,141
Condensate	7,703	5,340	17,892	10,827
Natural gas liquids	2,118	1,108	4,557	2,024
Total	$ 27,317	$ 13,870	$ 64,362	$ 29,992

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

Revenue from product sales for the second quarter of 2017 increased by 97% when compared to the second quarter of 2016 and decreased by 26% when compared to the immediately preceding quarter. For the six month periods, the increase in year-over-year revenue from product sales was 115%. Production volumes grew 9% and 18% year over year, respectively, for the three and six month periods. Year over year, per-Boe pricing strengthened by 81% and 83%, respectively, for the three and six month periods, while decreasing by 12% over the immediately preceding quarter.

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

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q2 2016	$ 7,422	$ 5,340	$ 1,108	$ 13,870
Effect of changes in production volumes	525	1,348	97	1,970
Effect of changes in average product prices	9,549	1,015	913	11,477
Revenue from product sales – Q2 2017	$ 17,496	$ 7,703	$ 2,118	$ 27,317

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q1 2017	$ 24,417	$ 10,189	$ 2,439	$ 37,045
Effect of changes in production volumes	(4,362)	(1,584)	(47)	(5,993)
Effect of changes in average product prices	(2,559)	(902)	(274)	(3,735)
Revenue from product sales – Q2 2017	$ 17,496	$ 7,703	$ 2,118	$ 27,317

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

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

The term liquids below refers to crude oil contracts. Although the Company has no crude oil production, the condensate and half of the NGL stream is priced with reference to crude oil and, as a result, the Company enters into crude oil contracts as a proxy for a condensate and NGL hedge.

The unrealized gain (loss) on commodity price contracts is a non-cash charge representing the change in the mark-to-market position of those contracts throughout the period.

	Three Months to June 30, 2017			Three Months to June 30, 2016		
Realized gain (loss)						
Natural gas	$ (1,495)	$ (0.24)	/Mcf	$ 1,877	$ 0.32	/Mcf
Liquids(2)	95	$ 0.40	/Bbl	739	$ 3.66	/Bbl
Total realized gain (loss) – cash(1)	$ (1,400)	$ (1.10)	/Boe	$ 2,616	$ 2.24	/Boe

	Six Months to June 30, 2017			Six Months to June 30, 2016		
Realized gain (loss)						
Natural gas	$ (4,917)	$ (0.36)	/Mcf	$ 4,258	$ 0.36	/Mcf
Liquids(2)	(1)	$ (0.00)	/Bbl	2,062	$ 4.89	/Bbl
Total realized gain (loss) – non-cash(1)	$ (4,918)	$ (1.76)	/Boe	$ 6,320	$ 2.64	/Boe

	Three Months to June 30, 2017			Three Months to June 30, 2016		
Unrealized gain (loss)						
Natural gas – change in fair value	$ 6,686	$ 1.08	/Mcf	$ (13,450)	$ (2.32)	/Mcf
Liquids – change in fair value(2)	2,785	$ 11.74	/Bbl	(2,353)	$ (11.65)	/Bbl
Total unrealized gain (loss) – non-cash(1)	$ 9,471	$ 7.44	/Boe	$ (15,803)	$ (13.51)	/Boe

	Six Months to June 30, 2017			Six Months to June 30, 2016		
Unrealized gain (loss)						
Natural gas – change in fair value	$ 20,439	$ 1.48	/Mcf	$ (14,916)	$ (1.26)	/Mcf
Liquids – change in fair value(2)	5,157	$ 10.29	/Bbl	(2,858)	$ (6.78)	/Bbl
Total unrealized gain (loss) – non-cash(1)	$ 25,596	$ 9.15	/Boe	$ (17,774)	$ (7.43)	/Boe

(1) The terms cash and non-cash are non-GAAP references.
(2) Liquids includes field condensate, plant pentanes, butane and propane.

The Company had in place the following commodity price contracts at the date of this report:

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jul – Dec 2017	38,000 GJ	AECO Cdn$2.71/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jul – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2018	26,850 Mmbtu	Chicago Cdn$4.10/Mmbtu
Jan – Jun 2018	4,000 Mmbtu	Chicago US$2.98/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Natural Gas Differential Swaps		
Jul – Dec 2017	8,000 GJ	Price at Station 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Jul – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Jul – Dec 2017	700 Bbls	$63.29 - $71.36 Cdn$/Bbl
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Jul – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	450 Bbls	$68.17 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	200 Bbls	$69.58 Cdn$/Bbl

During the second quarter of 2017, the Company realized a loss from commodity price contracts settled during the quarter in the amount of $1.4 million, compared to a gain of approximately $2.6 million in the second quarter of 2016. During the first six months of 2017, the Company realized a loss from commodity price contracts in the amount of $4.9 million compared to a gain of $6.3 million in the first six months of 2016. The majority of the loss for the first six months of 2017 (84%) related to natural gas differential swaps between Chicago and AECO and these expire at the end of 2017.

The fair market value of contracts outstanding at June 30, 2017 was a net asset position of $3.4 million (June 30, 2016 – net liability of $9.8 million) and is included in current and non-current assets or current and non-current liabilities, as appropriate. For the three and six months ended June 30, 2017, this resulted in unrealized mark-to-market gains of $9.5 million and $25.6 million, respectively, (2016 – losses of $15.8 million and $17.8 million, respectively) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

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

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

Royalties

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period	$ 1,872	$ 227	$ 4,738	$ 1,149
Percentage of revenue from product sales	6.9%	1.6%	7.4%	3.8%
Per Boe	$ 1.47	$ 0.19	$ 1.69	$ 0.48

Royalties in the second quarter of 2017, as a percentage of revenue from product sales, increased to 6.9% from 1.6% in the second quarter of 2016 and increased to 7.4% from 3.8% for the six months ended June 30, 2017 from the same period in 2016. Royalties increased due to higher production revenue driven largely by an increase in natural gas pricing. These increases were partially offset by an increase in wells eligible for the BC Deep Well Royalty Credit Program, which reduces the royalty rate on eligible wells from 13% to 6% for approximately two years. In the second quarter of 2017, 28 wells qualified for the 6% royalty rate versus 17 wells in the second quarter of 2016 and 27 wells in the immediately preceding quarter. The timing of receipt of infrastructure royalty credits also plays a role in quarterly comparisons with $0.5 million of infrastructure royalty credits received in the second quarter of 2016. No infrastructure royalty credits were received in the first or second quarters of 2017. Excluding royalty credits, higher production revenue in the three and six months ended June 30, 2017, from a combination of both stronger pricing and increased production volumes, was the main driver of the higher royalties relative to the same periods in 2016.

Storm has remaining infrastructure royalty credits of $8.1 million that will reduce future royalties. The timing of receipt and accounting recognition of future credits is dependent on commodity prices and production levels from individual wells and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially, as these credits are recognized.

Production Costs

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period	$ 8,577	$ 7,906	$ 17,482	$ 16,099
Percentage of revenue from product sales	31.4%	57.0%	27.2%	53.7%
Per Boe	$ 6.74	$ 6.76	$ 6.25	$ 6.73

Total production costs for the three and six months ended June 30, 2017 increased by 8% and 9% when compared to the same periods of 2016. The increase in total production costs is aligned with increased production at Umbach, partially offset by lower natural gas processing fees as a result of a new processing agreement that came into effect on January 1, 2017.

Production costs per Boe for the second quarter of 2017 were essentially flat compared to the second quarter of 2016. Lower per-unit processing costs associated with the new processing agreement were almost completely offset by the firm processing commitment payments incurred during the planned maintenance turnaround at the McMahon Gas Plant. Production costs per Boe for the first six months of 2017 decreased by 7% when compared to the same period of 2016 as a result of a lower per-unit fee associated with the new processing arrangement while production growth reduced the fixed cost component of per-Boe costs.

Transportation Costs

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period	$ 1,371	$ 388	$ 2,419	$ 1,033
Percentage of revenue from product sales	5.0%	2.8%	3.8%	3.4%
Per Boe	$ 1.08	$ 0.33	$ 0.86	$ 0.43

Transportation costs include pipeline tariffs for natural gas sold at Station 2, as well as trucking costs for condensate. Total transportation costs for the second quarter of 2017 increased by $1.0 million when compared to the second quarter of 2016. Transportation costs for the first six months of 2017 increased by $1.4 million when compared to the same period in 2016. Higher transportation costs in the second quarter of 2017 are due to increased trucking costs attributed to road bans, an increase in natural gas sold at Station 2, and higher condensate production. Natural gas sold at Station 2 increased from 13% of total natural gas production volumes in the second quarter of 2016 to 33% in the second quarter of 2017 and condensate production for the second quarter of 2017 increased 25% over the same period in 2016.

As the sales point for natural gas shipped on the Alliance Pipeline is the gas processing facility in British Columbia, the sales price received by the Company is net of the cost of transporting natural gas to Chicago and is thus captured on a net basis as part of revenue from product sales.

Field Netbacks

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

Three Months to June 30, 2017	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.81	$ 57.65	$ 20.45	$ 21.45
Royalties	(0.15)	(5.41)	(1.97)	(1.47)
Production costs	(1.38)	-	-	(6.74)
Transportation costs	(0.07)	(6.87)	-	(1.08)
Field operating netback	$ 1.21	$ 45.37	$ 18.48	$ 12.16
Realized gain (loss) on commodity price contracts	(0.24)	0.71	-	(1.10)
Field operating netback including hedging	$ 0.97	$ 46.08	$ 18.48	$ 11.06

Three Months to June 30, 2016	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 1.28	$ 50.05	$ 11.63	$ 11.86
Royalties	0.05	(4.43)	(0.63)	(0.19)
Production costs	(1.36)	-	-	(6.76)
Transportation costs	(0.03)	(2.14)	-	(0.33)
Field operating netback	$ (0.06)	$ 43.48	$ 11.00	$ 4.58
Realized gain on commodity price contracts	0.32	6.92		2.24
Field operating netback including hedging	$ 0.26	$ 50.40	$ 11.00	$ 6.82

Six Months to June 30, 2017	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.04	$ 61.31	$ 21.78	$ 23.00
Royalties	(0.19)	(5.72)	(2.22)	(1.69)
Production costs	(1.27)	-	-	(6.25)
Transportation costs	(0.08)	(4.62)	-	(0.86)
Field operating netback	$ 1.50	$ 50.97	$ 19.56	$ 14.20
Realized loss on commodity price contracts	(0.36)	-	-	(1.76)
Field operating netback including hedging	$ 1.14	$ 50.97	$ 19.56	$ 12.44

Six Months to June 30, 2016	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 1.45	$ 45.34	$ 11.06	$ 12.55
Royalties	-	(3.96)	(1.00)	(0.48)
Production costs	(1.36)	-	-	(6.73)
Transportation costs	(0.03)	(2.69)	-	(0.43)
Field operating netback	$ 0.06	$ 38.69	$ 10.06	$ 4.91
Realized gain on commodity price contracts	0.36	8.63	-	2.64
Field operating netback including hedging	$ 0.42	$ 47.32	$ 10.06	$ 7.55

(1) Production costs of condensate and natural gas liquids are presented within natural gas costs.
(2) Realized gains and losses on crude oil contracts are included in condensate field operating netback including hedging.

Excluding realized gains and losses on commodity price contracts, the field operating netback per Boe in the second quarter of 2017 increased by 166% to $12.16 compared to $4.58 for the second quarter of 2016. For the six months ended June 30, 2017, the field operating netback per Boe increased by 189% to $14.20 compared to $4.91 for the same period in 2016. The increase in the field operating netback for the second quarter of 2017 is primarily due to an 81% increase in revenue as a result of a price recovery from 2016. Year over year, per-Boe production revenue for the six months ended June 30, 2017 increased by $10.45, or 83%, with price recovery also the dominant variable in the considerable improvement to the field operating netback. Year over year, production costs per Boe for the six months ended June 30, 2017 decreased 7% as a result of lower natural gas processing fees.

General and Administrative Costs

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period – before recoveries	$ 1,613	$ 1,434	$ 3,782	$ 3,376
Overhead recoveries	(119)	(43)	(614)	(458)
Charge for period – net of recoveries	$ 1,494	$ 1,391	$ 3,168	$ 2,918
Per Boe	$ 1.17	$ 1.19	$ 1.13	$ 1.22

General and administrative costs before recoveries for the second quarter and first six months of 2017 increased by 13% and 12%, respectively, when compared to the same periods of 2016. The increase is primarily attributable to incremental costs associated with the transition of executive roles within the Finance group. Overhead recoveries for the periods presented fluctuate in response to the relative magnitude of field capital expenditures.

Net general and administrative costs for the second quarter of 2017 on a per-Boe measure decreased by 2% compared to the second quarter of 2016, and decreased by 7% when comparing the first six months of 2017 to the same period in 2016. General and administrative costs for the first and fourth quarters of a fiscal year tend to be higher due to the annual bonus payout, if earned, and the inclusion of certain costs specific to year-end reporting. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Share-Based Compensation

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period	$ 948	$ 729	$ 1,902	$ 1,552
Per Boe	$ 0.74	$ 0.62	$ 0.68	$ 0.65

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 30% in the second quarter of 2017 compared to the second quarter of 2016 and increased by 23% when comparing the six month periods. The increase in share-based compensation in both the three and six month periods is primarily attributable to a higher option valuation associated with options granted in December 2016.

Depletion and Depreciation

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Depletion	$ 8,715	$ 8,357	$ 19,328	$ 17,076
Depreciation	1,458	1,243	2,863	2,472
Charge for period	$ 10,173	$ 9,600	$ 22,191	$ 19,548
Per Boe	$ 7.99	$ 8.21	$ 7.93	$ 8.18

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

The charge for depreciation for the period relates to facility and field 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.

A 9% increase in production volumes resulted in the total charge for depletion and depreciation increasing by 6% in the second quarter of 2017 compared to the same quarter of 2016. Comparing the six month periods, production volumes grew by 18% with the depletion and depreciation charge growing by 14%. The quarterly and year-to-date per-Boe decrease of 3% corresponds to lower finding and development costs at Umbach. Increased depreciation charges year over year corresponds to increased investment in facilities.

Interest and Finance Costs

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Charge for period	$ 974	$ 793	$ 2,050	$ 1,477
Average interest rate[1]	4.4%	4.3%	4.8%	4.2%
Per Boe	$ 0.76	$ 0.68	$ 0.73	$ 0.62

(1) Includes financing and standby fees.

Interest costs for the second quarter of 2017 increased by 23% compared to the same quarter of 2016, and increased by 39% when comparing the six month periods, primarily driven by additional bank borrowings used to fund development of the Company's Umbach property.

The increase in the average interest rate to 4.8% for the six months ended June 30, 2017 compared to 4.2% for the same period in 2016 is due to an increase in financing fees attributed to the increase in the Company's credit facility at the last review.

The interest rate on the Company's credit facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been recognized in respect of potential future income tax reductions resulting from the use of accumulated tax losses. Details of Storm's tax pools are as follows:

Tax Pool	As at June 30, 2017	Maximum Annual Deduction
Canadian oil and gas property expense	40,000	10%
Canadian development expense	107,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	83,000	20 - 100%
Operating losses	209,000	100%
Other	2,000	20 - 100%
Total	463,000	

Net Income (Loss)

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Net income (loss)	$ 9,752	$ (20,493)	$ 30,383	$ (25,477)
Per basic and diluted share	$ 0.08	$ (0.17)	$ 0.25	$ (0.21)

The effect on net income of the mark-to-market valuation of commodity price contracts was significant for the three and six months ended June 30, 2017. The unrealized gain on commodity price contracts for the three and six months ended June 30, 2017 amounted to $9.5 million and $25.6 million, respectively, compared to an unrealized loss for the three and six months ended June 30, 2016 of $15.8 million and $17.8 million, respectively.

The increase in net income, excluding unrealized gains and losses on commodity price contracts, in the second quarter of 2017 compared to the second quarter of 2016 and when comparing the six month periods is primarily attributed to higher revenue from product sales due to increases in product prices and production volumes.

Of the per-share net income of $0.08 for the second quarter of 2017 and $0.25 for the six months ended June 30, 2017, $0.08 and $0.21, respectively, represented the unrealized gain on commodity price contracts.

Funds Flow

	Three Months to June 30, 2017		Three Months to June 30, 2016		Six Months to June 30, 2017		Six Months to June 30, 2016	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$11,629	$0.10	$5,781	$0.05	$29,587	$0.24	$13,636	$0.11

Funds flow for the second quarter of 2017 increased by 101% from the second quarter of 2016, and by 117% when comparing the first six months of 2017 to the same period in 2016. Compared to the second quarter of 2016, the increase in funds flow in the second quarter of 2017 was primarily due to an 81% increase in Storm's realized price on a per-Boe basis coupled with a 9% increase in production. A similar story emerges when comparing the first six months of 2017 to the same period in 2016, as funds flow benefited from a realized price that was 83% higher while production increased 18%. The aforementioned increases to funds flow in both periods from higher realized prices and higher production were partially offset by a realized loss on commodity price contracts.

The Company uses funds flow, a measure that is not defined under IFRS. Funds flow is cash from operations before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies and is used by lenders to establish interest rates applied to credit facilities.

Corporate Netbacks

($/Boe)	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Revenue from product sales	21.45	11.86	23.00	12.55
Realized (loss) gain on commodity price contracts	(1.10)	2.24	(1.76)	2.64
Royalties	(1.47)	(0.19)	(1.69)	(0.48)
Production	(6.74)	(6.76)	(6.25)	(6.73)
Transportation	(1.08)	(0.33)	(0.86)	(0.43)
General and administrative	(1.17)	(1.19)	(1.13)	(1.22)
Interest and finance costs	(0.76)	(0.68)	(0.73)	(0.62)
Funds flow per Boe	9.13	4.95	10.58	5.71
Share-based compensation	(0.74)	(0.62)	(0.68)	(0.65)
Depletion, depreciation and accretion	(8.08)	(8.29)	(8.01)	(8.25)
Exploration and evaluation costs expensed	(0.06)	-	(0.13)	-
Unrealized revaluation loss on investment	(0.03)	(0.04)	(0.04)	(0.03)
Unrealized gain (loss) on commodity price contracts	7.44	(13.51)	9.15	(7.43)
Net income (loss) per Boe	7.66	(17.51)	10.87	(10.65)

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, increased marginally to $8.67 in the second quarter of 2017 compared to $8.63 for the equivalent quarter of 2016 and decreased 5% to $8.11 for the first six months of 2017 compared to $8.57 for the first six months of 2016. Transportation costs are excluded as the sales price on a portion of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago. Comparing the second quarter of 2017 and the first six months of 2017 to the same periods in 2016, all components of controllable cash costs decreased on a per-Boe basis with the exception of interest costs which increased due to an increase in bank borrowings. Lower natural gas processing fees commencing January 1, 2017 have resulted in reductions in cash costs per commodity unit.

INVESTMENT AND FINANCING

Financial Resources and Liquidity

On April 25, 2017, the credit facility was increased to $165.0 million from $130.0 million in recognition of production and reserve growth at Umbach. The credit facility is available until April 27, 2018 at which time the borrowing base amount will be reviewed using independently evaluated reserve information. In the ordinary course of business, the Company has the option to extend the credit facility for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The credit facility is syndicated with three banks.

At June 30, 2017, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the facility credit limit. At June 30, 2017, debt including working capital deficiency amounted to $90.6 million, representing 55% of the available credit facility.

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 expenditure 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 updates the Board on progress at least four times a year.

Capital Expenditures

Minimal drilling and completions activity in the second quarter of 2017 was due to spring road bans being extended into mid-July which resulted in the Company spending $4.3 million (2016 - $0.6 million) on field operations.

In the first six months of 2017, the Company spent $31.7 million (2016 - $24.6 million) on field operations, primarily on drilling and completing wells at Umbach. During the six months ended June 30, 2017, six 100% working interest horizontal wells were drilled, four 100% working interest horizontal wells were completed and six horizontal wells were brought on production. At June 30, 2017 there was one standing completed well and eight wells awaiting completion. Major field capital outlays in the first six months of 2017 included $19.2 million on drilling and completions, $7.7 million on equipping and pipelines and $3.5 million on facilities, all in the Umbach area.

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Land and lease	$ 150	$ 314	$ 407	$ 1,000
Drilling	-	12	9,879	11,895
Completions	168	-	9,271	4,062
Facilities	1,854	172	3,535	6,352
Equipping and pipelines	2,081	86	7,716	1,186
Recompletions and workovers	44	17	846	50
Property acquisition, adjustments and administrative assets	10	12	10	14
Total capital expenditures	$ 4,307	$ 613	$ 31,664	$ 24,559

Net capital investment was allocated as follows:

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Exploration and evaluation	$ 150	$ 314	$ 400	$ 989
Property and equipment	4,157	299	31,264	23,570
Total capital expenditures	$ 4,307	$ 613	$ 31,664	$ 24,559

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at June 30, 2017 corresponds to a limited level of field activity at Umbach during the second quarter.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at June 30, 2017 was $33.8 million (2016 - $28.3 million) and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, and (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value was 2.1% (December 31, 2016 – 2.2%). Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources and with reference to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to June 30, 2017 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds[1] ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended Dec.31/14	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended Dec.31/15	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Year ended Dec.31/16	Stock option exercises	1,297	$ 1.97	2,558
Six months to Jun.30/17	Stock option exercises	793	$ 1.83	1,456
Total at June 30, 2017		121,557	$ 3.26	$ 395,930

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

During the first six months of 2017, stock options were exercised at an average price of $1.83 per optioned share and 793,000 common shares were issued for proceeds of $1,456,000.

Issued and outstanding common shares at June 30, 2017 and at August 15, 2017, the date of this MD&A, totaled 121,556,812.

CONTRACTUAL OBLIGATIONS

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

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

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.5 million over the term of the lease. At June 30, 2017, the remaining office lease commitment is $1.1 million. In addition, the Company has natural gas transportation and processing commitments valued at a total of approximately $346.6 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 30, 2017 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results from the fourth quarter of 2015 to mid-way through the third quarter of 2016 were affected by one dominant trend – production growth was insufficient to offset the relentless fall in commodity prices. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to increase production and to implement a larger capital expenditure program. As such, there was a significant increase in capital spending in the fourth quarter of 2016, while funds flow was strong, far outpacing that achieved in any of the prior quarters of 2016 and 2015. This positive trend continued into the first quarter of 2017, with another active capital expenditure program that resulted in a step change in average daily production along with a material increase in funds flow, primarily due to the improved pricing dynamic. The second quarter of 2017 saw a retreat in benchmark pricing for natural gas, condensate and NGL and a decrease in volumes due to a planned maintenance turnaround at the McMahon Gas Plant in June, which affected revenue and funds flow. With road bans in place for the better part of the second quarter of 2017, capital expenditures were limited as no wells were drilled or completed during the quarter.

	2017		2016				2015	
($000s unless otherwise stated)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue from product sales	27,317	37,045	26,244	21,047	13,870	16,121	14,480	16,283
Funds flow	11,629	17,958	11,985	8,759	5,781	7,855	9,182	7,982
Per share – basic and diluted ($)	0.10	0.15	0.10	0.07	0.05	0.07	0.08	0.07
Net income (loss)	9,752	20,631	(12,898)	(85)	(20,493)	(4,984)	1,850	(961)
Per share – basic and diluted ($)	0.08	0.17	(0.11)	(0.00)	(0.17)	(0.04)	0.02	(0.01)
Net capital expenditures	4,307	27,357	33,399	6,980	613	23,946	31,081	(4,116)[2]
Average daily production (Boe)	13,991	16,947	13,320	13,285	12,852	13,418	10,730	9,654
Debt including working capital deficiency[1]	90,582	97,864	89,841	69,303	71,254	77,162	61,721	39,994

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

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended June 30, 2017 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary: further, it may change between reporting periods. Variations between amounts estimated and actual results could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

Estimates of quantities of proven and probable reserves of natural gas and NGL (which includes condensate) are not a financial measurement. However, estimated future cash flows associated with reserves are used in impairment assessments for exploration and evaluation assets and property and equipment, the measurement of decommissioning obligations and depletion and depreciation of property and equipment. Such estimates of cash flows involve assumptions regarding future commodity prices, exchange rates, discount rates, inflation rates and future production and transportation costs and, of necessity, involve uncertainty. Reserve estimates are prepared annually by independent qualified reserve evaluators in accordance with independently established industry standards using, in part, data supplied by the Company. The results of the independent reserve evaluation are reviewed by the Reserves Committee of the Company's Board of Directors. In certain circumstances the Company will prepare internal estimates of reserves which may be used in accounting measurements applicable to interim reporting periods.

Accounts Receivable, Accounts Payable and Accrued Liabilities

At the end of each reporting period the Company estimates the amount receivable from product sales and from joint venture partners to the extent that these amounts are not determinable from purchaser statements or amounts invoiced to partners. In addition, the Company estimates the cost of services and materials provided by suppliers during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes such revenues and costs using well established measurement procedures. Nonetheless, such procedures reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced, either to or by the Company, relate in large part to the Company's capital expenditure programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts receivable, accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity the amount subject to estimation may be a large part of the total amount.

Commodity Price Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty. Crude oil contracts are used as a proxy for condensate and NGL contracts as part of the Company's condensate and NGL stream is priced with reference to crude oil index prices.

Exploration and Evaluation Assets

Costs incurred by the Company in the assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences or reserves are assigned, or are expensed if management determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. The amounts transferred to property and equipment, or expensed, and the timing of the decisions relative to each, are subject to measurement uncertainty. Furthermore, the carrying amount of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods. The carrying amount of exploration and evaluation assets is reviewed at the end of each reporting period for indicators of impairment. If such indicators exist the carrying amount will be measured against the estimated recoverable amount and if necessary reduced. This review involves estimates and judgments by management and thus involves a high degree of uncertainty.

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management, and the estimates used could differ from similar estimates developed by other parties. In addition, acquired property and equipment is initially recorded at fair value as determined by management. Measurement of fair value includes estimation and judgment and is inherently subjective and uncertain.

Property and equipment is subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made.

The carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount; as a result adjustments to the carrying amount may be made. All of these involve assumptions regarding uncertain future events and circumstances.

Decommissioning Liability

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

Share-Based Compensation

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

Income Taxes

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

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's August 15, 2017 press release, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold;
- future production volumes in the fourth quarter of 2017 and 2018, annual production for 2017 and production growth to 27,000 Boe per day in 2018, production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2017 guidance;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2017 capital expenditure program and the preliminary 2018 capital expenditure program;
- future drilling, completion and tie-in of wells along with the associated costs on a per-well basis;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- future availability of drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency including estimated 2017 year-end net debt of $100 to $120 million;
- availability and use of credit facilities;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2017 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and natural gas liquids, specifically a reduction of production costs as a result of a new processing agreement effective January 1, 2017;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

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

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include the material uncertainties and risks described or incorporated by reference in this MD&A under “Critical Accounting Estimates”; “Business Risks”; “Financial Reporting Update”; and the material assumptions and observations described under the headings “Overview”; “Production and Revenue”; “Realized and Unrealized Gain (Loss) on Commodity Price Contracts”; “Royalties”; “Production Costs”; “Transportation Costs”; “Field Netbacks”; “General and Administrative Costs”; “Share-Based Compensation”; “Depletion and Depreciation”; “Interest and Finance Costs”; “Income Taxes”; “Net Income (Loss)”; “Funds Flow”; “Financial Resources and Liquidity”; “Capital Expenditures”; “Accounts Payable and Accrued Liabilities”; “Decommissioning Liability”; “Share Capital”; “Contractual Obligations”; industry conditions including commodity prices, facility and pipeline capacity constraints and access to processing facilities and to market for production; currency fluctuations; imprecision of reserve estimates and related costs including future royalties, production and transportation costs and future development costs; environmental risks; competition from other industry participants; the lack of availability of qualified personnel or management; stock market volatility; ability to access sufficient capital from internal and external sources; and the ability of the Company to realize value from its properties. All of these caveats should be considered in the context of current economic conditions, in particular low, in a historical context, prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing domestic and international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company’s business. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm’s actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

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

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles (“GAAP”). Specifically, “debt including working capital deficiency”, “field operating netbacks”, “field operating netbacks including hedging”, “cash costs”, the terms “cash” and “non-cash”, and measurements “per commodity unit” and “per Boe” do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. Non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, lenders, analysts and other parties.

Field operating netbacks and field operating netbacks including hedging are common non-GAAP measurements applied in the oil and gas industry and are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting royalties, production and transportation expenses from revenue from product sales and are presented on a per-Boe basis.

Controllable cash costs per Boe, including production costs, general and administrative costs and interest and finance costs, are used by management to assess financial and operational performance.

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of commodity price contracts. Management believes this is a key measure to assess the Company's liquidity and is used by the Company's lenders to set corporate interest rates.

BUSINESS RISKS

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. Information with respect to such risks is set out in Storm's Annual Information Form dated March 31, 2017 for the year ended December 31, 2016 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2016 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

There were no material new or amended accounting standards adopted during the quarter ended June 30, 2017.

Future Accounting Policy Changes

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts*. The standard is required to be adopted either retrospectively or using the modified transition approach for fiscal years beginning on or after January 1, 2018, with early adoption permitted. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery. Upon initial assessment of the Company's significant revenue contracts, the adoption of IFRS 15 may result in presentation changes in revenue and transportation which are not expected to affect net income or loss.

In July 2014, the IASB issued IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected loss" impairment method and a substantially reformed approach to hedge accounting. This standard is effective for annual periods beginning on or after January 1, 2018. The Company's financial assets primarily consist of accounts receivable and derivative commodity price contracts. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. Upon initial assessment, the Company does not expect that the adoption of IFRS 9 will have a material effect on the Company.

In January 2016 the IASB issued IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for most leases. This standard replaces IAS 17 *Leases* and will be effective for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if IFRS 15 *Revenue from Contracts with Customers* is also adopted. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a "right-to-use asset" for essentially all lease contracts. The Company is currently evaluating the effect of this standard.

ADDITIONAL INFORMATION

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

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	June 30, 2017	December 31, 2016
ASSETS		
Current		
Accounts receivable (Note 10)	$ 3,032	$ 13,199
Prepaids and deposits	702	1,176
Fair value of commodity price contracts (Note 10)	4,355	483
	8,089	14,858
Fair value of commodity price contracts (Note 10)	427	-
Exploration and evaluation (Note 3)	110,679	110,395
Property and equipment (Note 4)	353,277	340,364
	$ 472,472	$ 465,617
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 10,157	$ 25,382
Fair value of commodity price contracts (Note 10)	1,341	20,622
	11,498	46,004
Bank indebtedness (Note 5)	84,159	78,834
Fair value of commodity price contracts (Note 10)	-	2,016
Decommissioning liability (Note 6)	23,294	18,983
	118,951	145,837
Shareholders' equity		
Share capital (Note 7)	391,444	389,316
Contributed surplus (Note 8)	10,100	8,870
Deficit	(48,023)	(78,406)
	353,521	319,780
Commitments (Note 12)		
	$ 472,472	$ 465,617

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

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

(Canadian $000s except per-share amounts) (unaudited)	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Revenue				
Revenue from product sales	$ 27,317	$ 13,870	$ 64,362	$ 29,992
Royalties	(1,872)	(227)	(4,738)	(1,149)
Net revenue	25,445	13,643	59,624	28,843
Realized (loss) gain on commodity price contracts (Note 10)	(1,400)	2,616	(4,918)	6,320
Unrealized gain (loss) on commodity price contracts (Note 10)	9,471	(15,803)	25,596	(17,774)
Net revenue and commodity price contracts	33,516	456	80,302	17,389
Expenses				
Production	8,577	7,906	17,482	16,099
Transportation	1,371	388	2,419	1,033
General and administrative	1,494	1,391	3,168	2,918
Share-based compensation (Note 8)	948	729	1,902	1,552
Depletion and depreciation (Note 4)	10,173	9,600	22,191	19,548
Exploration and evaluation costs expensed (Note 3)	75	-	373	-
Accretion (Note 6)	112	92	214	179
Interest and finance costs	974	793	2,050	1,477
Unrealized revaluation loss on investment	40	50	120	60
Total expenses	23,764	20,949	49,919	42,866
Net income (loss) and comprehensive income (loss) for the period	$ 9,752	$ (20,493)	$ 30,383	$ (25,477)
Net income (loss) per share (Note 9)				
Basic and diluted	$ 0.08	$ (0.17)	$ 0.25	$ (0.21)

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Six Months to June 30, 2017
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the period	-	-	30,383	30,383
Issue of common shares (Note 7)	1,456	-	-	1,456
Share-based compensation (Note 8)	-	1,902	-	1,902
Share-based compensation on options exercised (Note 7)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 10,100	$ (48,023)	$ 353,521

(Canadian $000s) (unaudited)				Six Months to June 30, 2016
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 385,766	$ 6,738	$ (39,946)	$ 352,558
Net loss for the period	-	-	(25,477)	(25,477)
Issue of common shares (Note 7)	1,451	-	-	1,451
Share-based compensation (Note 8)	-	1,552	-	1,552
Share-based compensation on options exercised (Note 7)	480	(480)	-	-
Balance, end of period	$ 387,697	$ 7,810	$ (65,423)	$ 330,084

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Operating activities				
Net income (loss) for the period	$ 9,752	$ (20,493)	$ 30,383	$ (25,477)
Non-cash items:				
Unrealized loss (gain) on commodity price contracts (Note 10)	(9,471)	15,803	(25,596)	17,774
Depletion, depreciation and accretion (Notes 4 and 6)	10,285	9,692	22,405	19,727
Share-based compensation (Note 8)	948	729	1,902	1,552
Exploration and evaluation costs expensed (Note 3)	75	-	373	-
Unrealized revaluation loss on investment	40	50	120	60
Funds flow	11,629	5,781	29,587	13,636
Net change in non-cash working capital items (Note 11)	5,648	(2,879)	6,001	11
	17,277	2,902	35,588	13,647
Financing activities				
Proceeds from issue of common shares (Note 7)	-	792	1,456	1,451
Increase (decrease) in bank indebtedness	(5,775)	3,579	5,325	16,954
	(5,775)	4,371	6,781	18,405
Investing activities				
Additions to exploration and evaluation assets (Note 3)	(150)	(314)	(400)	(989)
Additions to property and equipment (Note 4)	(4,157)	(299)	(31,264)	(23,570)
Net change in non-cash working capital items (Note 11)	(7,195)	(6,660)	(10,705)	(7,493)
	(11,502)	(7,273)	(42,369)	(32,052)
Change in cash during the period	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	$ -	$ -	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three and six months ended June 30, 2017 and 2016

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 primarily in the province of British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These unaudited condensed interim consolidated financial statements (the "financial statements") include the accounts of Storm and its wholly owned subsidiary, Storm Gas Resource Corp. All inter-entity transactions have been eliminated upon consolidation. Storm's operations are viewed as a single operating segment by the chief decision maker of the Company for the purpose of resource allocation and assessing asset performance.

2. BASIS OF PRESENTATION

Statement of Compliance

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). These financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company's audited financial statements as at and for the years ended December 31, 2016 and 2015. All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on August 15, 2017.

Basis of Measurement

The Company's financial statements have been prepared on a going concern basis consistent with prior periods, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 10.

Significant Accounting Judgments, Estimates and Assumptions

The preparation of the financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, shareholders' equity, revenue 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 reporting period that the changes to estimates are made.

Critical judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 5 to the Company's audited consolidated financial statements for the year ended December 31, 2016.

3. EXPLORATION AND EVALUATION

	Six Months Ended June 30, 2017	Year ended December 31, 2016
Balance, beginning of period	$ 110,395	$ 119,356
Additions	400	1,402
Expiries (exploration and evaluation expense)	(373)	(41)
Future decommissioning costs	257	100
Disposals	-	(100)
Transfer to property and equipment	-	(10,322)
Balance, end of period	$ 110,679	$ 110,395

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at June 30, 2017 and none were identified.

4. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2017	Year ended December 31, 2016
Cost		
Balance, beginning of period	$ 466,700	$ 389,781
Additions	31,264	64,136
Future decommissioning costs	3,840	2,581
Disposals	-	(120)
Transfer from exploration and evaluation assets	-	10,322
Balance, end of period	$ 501,804	$ 466,700
Accumulated depletion and depreciation		
Balance, beginning of period	$ (126,336)	$ (86,826)
Depletion and depreciation	(22,191)	(39,510)
Balance, end of period	$ (148,527)	$ (126,336)
Net book value, beginning of period	$ 340,364	$ 302,955
Net book value, end of period	$ 353,277	$ 340,364

Management reviewed the carrying amounts of property and equipment for indicators of impairment at June 30, 2017 and none were identified.

5. BANK INDEBTEDNESS

As at June 30, 2017, the Company had an extendible revolving credit facility in the amount of $165.0 million (December 31, 2016 – $130.0 million) based on a bank determined borrowing base related to the Company’s producing reserves. The credit facility is available to the Company until April 27, 2018, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one year later. Interest is paid on the credit facility at bankers’ acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount. At June 30, 2017, the Company is in compliance with all covenants under the credit facility.

As at June 30, 2017, the Company had issued letters of credit in the amount of $8.2 million (December 31, 2016 - $8.1 million) in support of future natural gas transportation and processing obligations and future reclamation liabilities. Availability under the Company’s credit facility is reduced by a like amount.

6. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company’s net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company’s decommissioning obligation is approximately $33.8 million (December 31, 2016 - $28.3 million), which is expected to be paid over the next 30 years with the majority of payments being made in the years 2034 to 2047. A risk-free discount rate of 2.1% (December 31, 2016 – 2.2%) and an inflation rate of 2.0% (December 31, 2016 – 1.6%) was used to calculate the present value of the decommissioning obligation, amounting to $23.3 million at June 30, 2017.

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

	Six Months Ended June 30, 2017	Year Ended December 31, 2016
Balance, beginning of period	$ 18,983	$ 16,016
Obligations incurred	1,909	3,159
Obligations disposed	-	(61)
Change in rate estimates(1)	2,188	(478)
Accretion expense	214	347
Balance, end of period	$ 23,294	$ 18,983

(1) Relates to changes in inflation rates, risk-free discount rates and estimated settlement dates.

7. 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, 2016	120,764	$ 389,316
Shares issued on stock option exercises	793	2,128
Balance as at June 30, 2017	121,557	$ 391,444

During the first six months of 2017, 793,000 common shares were issued upon the exercise of stock options for proceeds of $1,456,000 and related prior period share-based compensation of $672,000 was transferred to share capital from contributed surplus.

8. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at June 30, 2017, a total of 12,155,681 common shares were available for issuance. Options in respect of 7,884,000 common shares were issued and outstanding at June 30, 2017, with options in respect of 4,271,681 common shares available for future issue.

At August 15, 2017, the date of this quarterly report, options in respect of 7,914,000 common shares were issued and outstanding and 4,241,681 are available for future issue.

Details of the options outstanding at June 30, 2017 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2016	8,387	$ 4.21
Granted during the period	290	$ 4.27
Exercised during the period	(793)	$ 1.83
Outstanding at June 30, 2017	7,884	$ 4.46
Number exercisable at June 30, 2017	3,665	$ 4.34

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
$2.64 - $3.95	1,891	2.5	$ 3.35	617	$ 3.35
$3.96 - $5.50	5,993	2.0	$ 4.80	3,048	$ 4.55
Total	7,884	2.1	$ 4.46	3,665	$ 4.34

The fair value of employee stock options is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility, forfeiture rate, weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the six months ended June 30, 2017 of $4.27 per share include the following:

	2017
Share price	$3.91 - $5.27
Exercise price	$3.91 - $5.27
Volatility	52%
Forfeiture rate	10%
Expected option life (years)	3.7
Risk-free interest rate	0.8% - 1.0%

No options were granted in the first six months of 2016.

Share-based compensation expense of $0.9 million and $1.9 million was charged to the consolidated statement of income (loss) during the three and six months to June 30, 2017, respectively (2016 - $0.7 million and $1.6 million, respectively) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company's share price using market data.

9. NET INCOME (LOSS) PER SHARE

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

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Net income (loss) for the period	$ 9,752	$ (20,493)	$ 30,383	$ (25,477)
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	121,557	119,742	120,764	119,467
Effect of shares issued	-	187	736	294
Weighted average number of common shares outstanding – basic	121,557	119,929	121,500	119,761
Dilutive effect of outstanding options(1)	125	-	202	-
Weighted average number of common shares outstanding - diluted	121,682	119,929	121,702	119,761
Net income (loss) per share				
Basic and diluted	$ 0.08	$ (0.17)	$ 0.25	$ (0.21)

(1) Excludes effect of 6.0 million and 5.9 million weighted average common shares related to stock options that were anti-dilutive for the three and six months ended June 30, 2017, respectively (5.7 million weighted average common shares related to stock options for each of the three and six months ended June 30, 2016).

10. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness and commodity price contracts.

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

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide continual and verifiable pricing information.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three and six months ended June 30, 2017.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at June 30, 2017:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 6,114	$ (1,759)	$ 4,355
Long-term asset	427	-	427
Current liability	(3,100)	1,759	(1,341)
Net position	$ 3,441	$ -	$ 3,441

As at December 31, 2016, the net financial liability and asset recognized in relation to the fair value of commodity price contracts was equal to the gross financial amounts as there were no offsets.

Accounts Receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at June 30, 2017, the Company's most significant marketer accounted for $1.5 million of total receivables and 60% of total revenues for each of the three and six months ended June 30, 2017. Where operations involve partners in a joint venture, the Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. Receivables from joint ventures are typically collected within one to three months of the joint venture bill being issued. As at June 30, 2017, there were no receivables outstanding for more than 30 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at June 30, 2017.

The maximum exposure to credit risk at June 30, 2017 was the carrying amount of accounts receivable of $3.0 million and commodity price contract assets of $4.8 million.

A provision for impairment is established when there is objective evidence that the Company will not be able to collect all amounts due according to the original terms of the receivable. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganization and default or significant delinquency in payments are considered indicators that a receivable is impaired.

Derivative Commodity Price Contracts

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts, a net asset position of $3.4 million (December 31, 2016 – net liability of $22.2 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the three and six months ended June 30, 2017, this resulted in unrealized mark-to-market gains of $9.5 million and $25.6 million, respectively (2016 – losses of $15.8 million and $17.8 million, respectively) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jul – Dec 2017	38,000 GJ	AECO Cdn$2.71/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jul – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2018	26,850 Mmbtu	Chicago Cdn$4.10/Mmbtu
Jan – Jun 2018	4,000 Mmbtu	Chicago US$2.98/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Natural Gas Differential Swaps		
Jul – Dec 2017	8,000 GJ	Price at Station 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Jul – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Jul – Dec 2017	700 Bbls	$63.29 - $71.36 Cdn$/Bbl
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Jul – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	450 Bbls	$68.17 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	200 Bbls	$69.58 Cdn$/Bbl

During the three and six months ended June 30, 2017, the Company realized losses from commodity price contracts in place in the amount of $1.4 million and $4.9 million, respectively (2016 – gains of $2.6 million and $6.3 million, respectively).

Sensitivities

Using the Company's actual production volumes, royalty rates and bank indebtedness for the first six months of 2017, the estimated after-tax effect that changes in certain factors would have on net income and net income per share is set out below:

	Six Months Ended June 30, 2017			
Factor		Change in Net Income		Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI[(1)]	$	600	$	-
$0.10/Mcf change in the price of natural gas	$	1,290	$	0.01
1% change in the interest rate	$	430	$	-

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

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

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to June 30, 2017	Three Months to June 30, 2016	Six Months to June 30, 2017	Six Months to June 30, 2016
Accounts receivable	$ 9,442	$ 28	$ 10,047	$ 1,721
Prepaids and deposits	199	(1,057)	474	(1,550)
Accounts payable and accrued liabilities	(11,188)	(8,510)	(15,225)	(7,653)
Change in non-cash working capital	$ (1,547)	$ (9,539)	$ (4,704)	$ (7,482)
Relating to:				
Operating activities	$ 5,648	$ (2,879)	$ 6,001	$ 11
Investing activities	(7,195)	(6,660)	(10,705)	(7,493)
Change in non-cash working capital	$ (1,547)	$ (9,539)	$ (4,704)	$ (7,482)
Interest paid during the period	$ 974	$ 765	$ 1,786	$ 1,338
Income taxes paid during the period	$ -	$ -	$ -	$ -

12. COMMITMENTS

At June 30, 2017, the Company has the following long-term commitments over the next five years and thereafter:

	2017	2018	2019	2020	2021	Thereafter	Total
Office lease	$ 436	$ 646	$ -	$ -	$ -	$ -	$ 1,082
Natural gas transportation and processing commitments	24,985	47,345	33,006	31,189	21,163	188,881	346,569
Total	$ 25,421	$ 47,991	$ 33,006	$ 31,189	$ 21,163	$ 188,881	$ 347,651

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

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Stock Exchange Listing

TSX Venture Exchange
Trading Symbol "SRX"

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Canadian Imperial Bank of Commerce
Royal Bank of Canada
Calgary, Alberta

Executive Offices

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Calgary, Alberta, T2P 3G4 Canada
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Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
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
NGL	Natural gas liquids
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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