STORM RESOURCES

2019 Q3 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
FINANCIAL				
Revenue from product sales(1)	31,417	51,253	124,751	151,459
Funds flow	11,973	22,227	41,080	69,151
Per share – basic and diluted ($)	0.10	0.18	0.34	0.57
Net income (loss)	(64)	7,174	8,407	13,253
Per share – basic and diluted ($)	(0.00)	0.06	0.07	0.11
Cash return on capital employed (“CROCE”)(2)	15%	21%	15%	21%
Return on capital employed (“ROCE”)(2)	9%	6%	9%	6%
Capital expenditures	32,841	21,845	72,930	47,663
Debt including working capital deficiency(2)(3)	123,342	84,648	123,342	84,648
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,557	121,557
Outstanding end of period - basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	18.36	27.24	23.50	27.88
Transportation costs	(5.83)	(5.98)	(5.84)	(5.94)
Revenue net of transportation	12.53	21.26	17.66	21.94
Royalties	0.19	(1.03)	(0.92)	(1.28)
Production costs	(5.88)	(5.54)	(5.96)	(5.52)
Field operating netback(2)	6.84	14.69	10.78	15.14
Realized gain (loss) on risk management contracts	1.64	(1.73)	(1.35)	(0.89)
General and administrative	(0.79)	(0.66)	(1.02)	(0.92)
Interest and finance costs	(0.69)	(0.49)	(0.67)	(0.61)
Funds flow per Boe	7.00	11.81	7.74	12.72
Barrels of oil equivalent per day (6:1)	18,596	20,455	19,443	19,900
Natural gas production				
Thousand cubic feet per day	91,053	101,905	95,013	98,154
Price (Cdn$ per Mcf)(1)	2.42	3.21	3.19	3.39
Condensate production				
Barrels per day	1,856	2,059	2,044	2,035
Price (Cdn$ per barrel)(1)	63.45	84.97	65.81	82.46
NGL production				
Barrels per day	1,564	1,412	1,563	1,506
Price (Cdn$ per barrel)(1)	2.29	38.64	12.59	35.92
Wells drilled (net)	1.0	-	6.0	-
Wells completed (net)	5.0	5.0	5.0	8.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts and lease liability.

PRESIDENT'S MESSAGE

2019 THIRD QUARTER HIGHLIGHTS

Production and funds flow were reduced by a 14-day outage at the McMahon Gas Plant and from shutting in wells during several periods of very low natural gas prices at AECO and BC Station 2. Construction of the 50 Mmcf per day Nig Gas Plant is ongoing with major equipment deliveries to the site beginning in September while start-up is planned for January 2020. A four-well pad in the Nig area was completed in June and July; however, the pipeline tie-in was not finished until mid-November as a result of delays due to rain and wet field conditions.

- Production was 9% lower year over year and was within the guidance range for the quarter of 18,000 to 20,000 Boe per day. Production was reduced by approximately 2,400 Boe per day due to an unplanned third-party outage at the McMahon Gas Plant (loss of 16,000 Boe per day for 14 days) and by approximately 800 Boe per day due to low natural gas prices at AECO and Station 2 (shut in 5,000 Boe per day for a total of 15 days).

- Liquids production (field condensate plus gas plant NGL) represented 18% of total production and 36% of production revenue.

- Three new horizontal wells have started producing in 2019 which has offset corporate declines. A four-well pad at Nig (includes one well in the lower Montney) will start production in mid-November which is expected to increase fourth quarter production to 22,000 to 24,000 Boe per day (the first three wells at Nig had average first year calendar day rates of 1,400 Boe per day sales).

- Revenue per Boe declined by 33% year over year. The NGL price declined 94% primarily as a result of lower contracted butane and propane prices during the current marketing period which runs from April 2019 to March 2020. The realized natural gas price declined by 25%, however, was still approximately 270% higher than the Station 2 price as a result of diversified sales.

- Controllable cash costs including transportation, production, general and administrative, and interest were $13.19 per Boe which is an increase from $12.67 per Boe in the prior year. Higher production cost was due to the effect of lower production levels on fixed costs while higher interest and finance costs were the result of debt increasing during the construction of the Nig Gas Plant.

- Funds flow was $12.0 million, or $0.10 per share, a decrease of 46% on a per-share basis year over year with the decrease largely the result of lower commodity prices and production being reduced by the McMahon Gas Plant outage.

- Net income was nil compared to $7.2 million in the prior year and is primarily attributable to lower commodity prices reducing the funds flow netback to $7.00 per Boe from $11.81 per Boe last year.

- Capital investment was $32.8 million which included $26.7 million for the Nig Gas Plant project (includes $4.3 million to drill and complete a horizontal well for acid gas disposal) plus $6.1 million to finish completing and pipeline connect a four-well pad at Nig.

- Year-to-date capital investment is $72.9 million with 60% invested in future growth opportunities (Nig Gas Plant project $42.1 million plus Fireweed $1.4 million).

- Total debt which includes the working capital deficiency was $123 million, represents approximately 60% utilization of the $205 million bank line, and is an increase from $91.0 million at the start of the year due to the large proportion of 2019 capital investment being directed to the Nig Gas Plant project. Total debt was 2.6 times annualized quarterly funds flow and is expected to decline below 2.0 times following completion of the Nig Gas Plant which increases funds flow by reducing per-Boe operating costs and improving liquids recovery.

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas, Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and totaled 121,000 net acres (172 net sections) at the end of the quarter with 78 horizontal wells (73.9 net) drilled to date.

Third quarter field activity was mainly focused on the Nig Gas Plant project which included site preparation, delivery of major equipment to the site, and drilling and completing a horizontal well for acid gas disposal. In addition, completion of a pad at Nig with four horizontal wells (4.0 net) was finished in July and the pipeline tie-in was finished in mid-November after being delayed by rain and wet field conditions. The four-well pad will evaluate different intervals in the Montney with two wells in the upper, one well in the mid and one well in the lower.

At the end of the quarter, there was an inventory of nine (8.5 net) drilled Montney horizontal wells that had not started producing which included five (4.5 net) completed wells. During the quarter, there were no new wells that started production.

Field activity in the fourth quarter will include the ongoing construction of the 50 Mmcf per day Nig Gas Plant and finishing the pipeline tie-in of a four-well pad at Nig.

At Umbach (100% working interest), production in the quarter was 16,430 Boe per day with 2,980 barrels per day of liquids (18%) and was reduced by the 14-day unplanned outage at the McMahon Gas Plant. There are currently four standing wells (4.0 net) with none having been completed. Produced raw natural gas is sour (1.2% H_2S) with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant where firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon plus 15 Mmcf per day at Stoddart). Field compression capacity totals 150 Mmcf per day raw gas with throughput in the second quarter averaging 94 Mmcf per day raw gas (includes 11 Mmcf per day raw from Nig).

At Nig (100% working interest), production from the three producing wells averaged 2,070 Boe per day with 430 barrels per day of liquids (21%) in the quarter which was reduced by the outage at the McMahon Gas Plant plus the wells were shut in for varying periods to complete an adjacent four-well pad. At the end of the quarter there were four standing and completed wells (4.0 net) which will start production in mid-November. Produced raw natural gas contains approximately 0.2% H_2S. The sour gas plant that is under construction has capacity of 50 Mmcf per day and start-up is planned for January 2020. Total estimated cost of the Nig Gas Plant project has increased to $86 million (was $81 million) with $11 million invested in 2018, $70 million planned for 2019 and the remaining $5 million in 2020. The project cost increased as a result of a higher cost for site construction as well as scope changes and now includes $77 million for the gas plant, $5 million for an acid gas injection well and $4 million for a sales pipeline. Sales volume from the gas plant is forecast to be 10,500 Boe per day with an estimated operating cost of less than $2.00 per Boe reducing the corporate operating cost to approximately $4.25 per Boe. Liquids recovery will improve and is forecast to be 27% of total production from the gas plant (43% condensate, 57% NGL).

At Fireweed (50% working interest), construction of a 50 Mmcf per day field compression facility (expandable to 100 Mmcf per day) is anticipated to begin in mid-2020 with start-up in late 2020 or early 2021. The estimated cost of the facility is $38 million which also includes an access road and sales pipeline. There is currently one standing well (0.5 net) with a length of 1,520 metres (36 frac stages) that has been completed which averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate and 1,140 barrels per day of frac water over the last 12 hours of a six-day clean-up (final flowing casing pressure of 4,800 kPa). Based on production history from offsetting horizontal wells, first year average field condensate-gas ratios are expected to be 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach.

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not reliable indicators of relative performance since wells are initially rate restricted for up to nine months to manage fluid rates. In addition, recent wells have been affected by outages which have totaled 43 days to date in 2019.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2014 - 2016 33 hz's[1]	22	1350 m	4.9 Mmcf/d[2] 19 Bbls/Mmcf[3] 33 hz's	4.3 Mmcf/d[2] 16 Bbls/Mmcf[3] 33 hz's	3.4 Mmcf/d[2] 13 Bbls/Mmcf[3] 33 hz's
Umbach 2017 - 2018 19 hz's	34	1895 m	4.6 Mmcf/d[2] 24 Bbls/Mmcf[3] 19 hz's	4.3 Mmcf/d[2] 20 Bbls/Mmcf[3] 18 hz's	4.1 Mmcf/d[2] 14 Bbls/Mmcf[3] 14 hz's
Nig 2018 3 hz's	37	2180 m	8.1 Mmcf/d[2] 29 Bbls/Mmcf[3] 3 hz's	8.2 Mmcf/d[2] 25 Bbls/Mmcf[3] 3 hz's	7.5 Mmcf/d[2] 21 Bbls/Mmcf[3] 3 hz's

(1) This table provides analysis of upper Montney wells only (2014 - 2016 wells exclude a middle Montney well).
(2) Raw gas rate.
(3) Bbls/Mmcf is the field condensate-gas ratio or barrels of field condensate per Mmcf raw.

Based on results from the 2017 and 2018 wells, Storm management is using 8 Bcf and 14 Bcf raw gas type curves (internal estimates) to forecast production at Umbach and Nig respectively. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth with the objective being to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward (future production growth is not hedged). The current hedge position (excluding price differential contracts which are shown in the financial statements) protects approximately 41% of forecast production for the fourth quarter of 2019 and 14% of forecast production for 2020.

Q4 2019	Crude Oil	850 Bpd	WTI Cdn$73.28/Bbl floor, Cdn$87.95/Bbl ceiling
		650 Bpd	WTI Cdn$81.51/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	38,000 Mmbtu/d (32.0 Mmcf/d)	Chicago Cdn$3.24/Mmbtu
		8,500 Mmbtu/d (7.2 Mmcf/d)	Sumas Cdn$2.67/Mmbtu
		1,000 GJ/d (0.8 Mmcf/d)	AECO Cdn$2.00/GJ
		3,670 GJ/d (2.9 Mmcf/d)	AECO Cdn$1.77/GJ floor, $2.28/GJ ceiling
		7,300 GJ/d (5.8 Mmcf/d)	Station 2 Cdn$1.93/GJ
2020	Crude Oil	375 Bpd	WTI Cdn$71.07/Bbl floor, Cdn$81.21/Bbl ceiling
		375 Bpd	WTI Cdn$71.92/Bbl
	Natural Gas	10,750 Mmbtu/d (9.1 Mmcf/d)	Chicago Cdn$3.33/Mmbtu
		2,000 Mmbtu/d (1.7 Mmcf/d)	NYMEX US$2.49 floor, US$2.62 ceiling
		1,750 Mmbtu/d (1.5 Mmcf/d)	Sumas Cdn$3.94/Mmbtu
		375 GJ/d (0.3 Mmcf/d)	AECO Cdn$2.00/GJ
		1,375 GJ/d (1.1 Mmcf/d)	AECO Cdn$1.77/GJ floor, $2.28/GJ ceiling
		3,250 GJ/d (2.6 Mmcf/d)	Station 2 Cdn$1.92/GJ

(1) The Alliance Pipeline tariff to Chicago is approximately Cdn$1.20 per Mmbtu including the cost of fuel.

Firm transportation commitments for natural gas provide sales diversification and are summarized below for 2020:

Alliance to Chicago(1)	57 Mmcf/d
Enbridge T-north to Station 2	18 Mmcf/d
Enbridge T-north & TCPL to AECO	14 Mmcf/d
Enbridge T-north to Station 2/Sumas(2)	12 Mmcf/d
Alliance to ATP	5 Mmcf/d
Total	**106 Mmcf/d**

(1) When available, Preferential Interruptible Service ('PITS') adds up to 14 Mmcf/d of capacity.
(2) Deliver at Station 2 for Sumas price less US$0.69/Mmbtu.

OUTLOOK

Production in the fourth quarter of 2019 is forecast to average 22,000 to 24,000 Boe per day with capital investment estimated to be $32 to $37 million (approximately 73% allocated to the Nig Gas Plant project). Production is below previous guidance mainly because of shut-ins during October due to the low natural gas price at Station 2 ($0.36 per GJ).

Updated guidance for 2019 is provided below. Changes include reducing forecast fourth quarter production due to low natural gas prices at Station 2 and updating forecast pricing to reflect actual prices to date plus the approximate forward strip for the remainder of the year. Approximately 70% of estimated capital investment is funding future growth (Nig Gas Plant project $70 million plus Fireweed $5 million).

2019 Guidance

	Previous August 13, 2019	Current November 12, 2019
Cdn$/US$ exchange rate	0.755	0.755
Chicago daily natural gas - US$/Mmbtu	$2.45	$2.45
Sumas monthly natural gas - US$/Mmbtu	$3.40	$3.50
AECO daily natural gas - Cdn$/GJ	$1.55	$1.65
Station 2 daily natural gas - Cdn$/GJ	$1.00	$0.90
WTI - US$/Bbl	$55.00	$56.00
Edmonton condensate diff - US$/Bbl	-$5.10	-$4.20
Est revenue net of transport (excl hedges) - $/Boe	$16.50 - $17.00	$17.25 - $17.75
Est operating costs - $/Boe	$5.75 - $6.00	$5.75 - $6.00
Est royalty rate (% revenue net transportation)	5% - 7%	5% - 6%
Est mid-point field operating netback - $/Boe	$9.87	$10.65
Est hedging loss - $ million	$4.0 - $5.0	$6.5 - $7.5
Est cash G&A - $ million	$6.0 - $6.5	$6.5 - $7.0
Est interest expense - $ million	$5.5 - $6.5	$5.0 - $5.5
Est capital investment (excl A&D) - $ million	$110.0	$105.0 - $110.0
Forecast fourth quarter production - Boe/d % liquids	23,000 - 25,000 18%	22,000 - 24,000 18%
Forecast annual production - Boe/d % liquids	20,000 - 22,000 18%	20,000 - 22,000 18%
Est annual funds flow - $ million	$55.0 - $61.0(1)	$58.7 - $64.5(1)

Horizontal wells drilled - gross	9 (7.5 net)	6 (6.0 net)
Horizontal wells completed - gross	8 (6.5 net)	5 (5.0 net)
Horizontal wells starting production - gross	7 (7.0 net)	7 (7.0 net)

(1) Based on the range for forecast annual production and using the mid-point for each of the estimated field operating netback, estimated cash G&A, estimated hedging gain or loss and estimated interest expense.

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/Bbl)	Capital Investment ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 13, 2018	$2.50	$1.25	$60.00	$128.0	$72.0 - $88.0	21,000 - 24,000
Feb 28, 2019	$2.60	$1.25	$55.00	$128.0	$67.0 - $79.0	21,000 - 24,000
May 14, 2019	$2.65	$1.20	$55.00	$128.0	$65.0 - $77.0	21,000 - 24,000
Aug 13, 2019	$2.45	$1.00	$55.00	$110.0	$55.0 - $61.0	20,000 - 22,000
Nov 12, 2019	$2.45	$0.90	$56.00	$105.0 - $110.0	$58.7 - $64.5	20,000 - 22,000

Natural gas prices have steadily declined since last winter primarily because of supply growth exceeding demand growth in both the US and Western Canada with price volatility amplified at AECO and Station 2 as a result of recurring pipeline restrictions and outages (several days of negative pricing). There are indications that supply growth in the US is slowing while Western Canadian production has been declining since mid-summer which has recently improved the AECO price and narrowed the NYMEX-AECO price differential. Future pricing for 2020 is approximately $1.85 per GJ at AECO and $1.60 per GJ at Station 2 which is materially higher than pricing to date in 2019 ($1.44 per GJ at AECO and $0.81 per GJ at Station 2). Station 2 pricing could continue to improve now that repairs on the T-south pipeline to Sumas have been completed (the failure in October 2018 reduced throughput by 15% to as much as 45%) and with expected start-up of the NGTL North Montney extension into northeast British Columbia in early 2020 (delayed from initial start-up date in mid-September 2019). Although only 18% of year-to-date natural gas sales has been at Station 2, most of Storm's incremental production growth will be directed to Station 2.

Capital investment in 2020 is expected to be $75 to $90 million (previous estimate was $80 million) which will be approximately equal to estimated funds flow at current strip pricing (WTI US$54/Bbl, Chicago US$2.45/Mmbtu, AECO $1.85/GJ, Station 2 $1.60/GJ, Edmonton condensate WTI –US$5/Bbl, Cdn$0.76 per US$1). Investment in 2020 includes:

- $35 to $50 million at Fireweed which includes constructing a 50 Mmcf per day field compression facility that is expandable to 100 Mmcf per day (50% working interest), drilling four to eight horizontal wells (2.0 to 4.0 net), and completing three to seven wells (1.5 to 3.5 net);

- $28 to $40 million at Nig and Umbach which includes drilling four horizontal wells (4.0 net) and completing three to seven horizontal wells (3.0 to 7.0 net).

Capital investment in both 2019 and 2020 has been reduced from earlier estimates as a result of 2019 funds flow being lower than initial expectations due to the unplanned outages at the McMahon Gas Plant and lower commodity prices. This delays growth from Fireweed with first production now expected in late 2020 or early 2021 (previously expected to be in the second half of 2020). Adjusting capital investment is the main way to maintain a strong balance sheet (an important part of Storm's business strategy) given that commodity prices and funds flow are less controllable.

Total debt exiting 2019 is forecast to be below 2.0 times annualized fourth quarter funds flow and is expected to decline further after start-up of the Nig Gas Plant which adds $15 to $20 million to 2020 funds flow depending on liquids pricing.

Corporate production is forecast to average 22,000 to 24,000 Boe per day in the fourth quarter of 2019 (4,000 to 4,300 barrels per day of liquids) and is forecast to increase to 27,000 to 30,000 Boe per day in the fourth quarter of 2020 (5,700 to 6,300 barrels per day of liquids). Average annual production in 2020 is forecast to be 24,000 to 26,000 Boe per day which represents an increase of approximately 25% from 2019 with liquids production increasing by approximately 45%. This includes the impact of a planned 25-day maintenance outage at the McMahon Gas Plant in September 2020 (financial effect will be largely mitigated by the Nig Gas Plant) and assumes first production from Fireweed in late 2020 or early 2021 depending on the timing to construct infrastructure.

The near-term plan remains focused on growing funds flow which will come from start-up of the Nig Gas Plant in early 2020 (reduces per-Boe operating costs and increases liquids production) and from first production at Fireweed in late 2020 or early 2021 (increases condensate production). Although planned growth has been delayed as a result of reducing 2019 and 2020 capital investment, this was necessary to maintain a strong balance sheet in response to 2019 funds flow being reduced by unplanned outages at the McMahon Gas Plant and by lower commodity prices. The start-up of Storm's Nig Gas Plant (100% working interest) diversifies processing and will reduce the effect of any future outages at third-party gas processing plants.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 12, 2019

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 November 12, 2019 for the three and nine months ended September 30, 2019.

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 nine months ended September 30, 2019. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2019, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2018, and (iii) the press release issued by the Company on November 12, 2019, 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 29, 2019 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

The Company trades on the Toronto Stock Exchange ("TSX") under the symbol "SRX".

This MD&A is dated November 12, 2019.

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

BASIS OF PRESENTATION

Financial data presented below have been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 2019, 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, 2018 and updated for new standards, as applicable, in Note 3 of the financial statements for the three and nine months ended September 30, 2019. 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 nine month periods ended September 30, 2018.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The third quarter of 2019 resembled much of the same when compared to the first six months of the year, marked by third-party outages and low commodity prices that reduced Storm's production and funds flow. As previously disclosed, the McMahon Gas Plant incurred a 14-day unplanned outage from July 30 to August 12 which was required to repair piping leaks and resulted in approximately 16,000 Boe per day being shut in. In addition, production was restricted in the quarter to meet firm processing and transportation commitments in response to ongoing weakness in Western Canadian natural gas prices. Third quarter production of 18,596 Boe per day was consistent with the low end of the previously announced guidance range of 18,000 to 20,000 Boe per day. Funds flow in the third quarter was down modestly from the immediately preceding quarter, largely due to lower production levels. Storm incurred capital expenditures of $33 million, lower than the $45 million previously disclosed due to timing of expenditures relating to the Nig Gas Plant with the difference now to be incurred in the fourth quarter.

During the third quarter of 2019, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 18% of total production and contributed 36% to revenue in the period compared to 38% of revenue in the immediately preceding quarter and 41% of revenue in the comparable quarter of 2018. As the majority of Storm's condensate and NGL revenue streams is based on crude oil reference prices, participation in the crude oil market remains an important part of Storm's business plan, particularly in light of the ability to focus drilling on areas where higher liquids recoveries are expected.

The natural gas price realized by the Company in the third quarter fell by 8% when compared to the second quarter of 2019, and was down 25% when compared to the same quarter of 2018. The decrease versus both the prior quarter and the third quarter of 2018 was the result of a decline in both US based and Western Canadian natural gas benchmark pricing due to elevated supply levels. Station 2 pricing continued to be affected by ongoing constraints on the T-south natural gas pipeline. When comparing to the same quarter in 2018, condensate and NGL prices were down 25% and 94%, respectively. Benchmark crude oil pricing decreased in 2019 compared to 2018 as a result of a lower oil demand forecast due to trade tensions between China and the US which continued to affect the global economy and fears of an oversupplied market, despite rising tensions in the Middle East. Elevated supply levels for NGL in Western Canada and constrained take-away capacity materially reduced Storm's realized NGL price. After bottoming out in July and August, propane prices have staged a modest recovery and thus Storm's NGL price net of transportation is still anticipated to be approximately 5% to 10% of WTI in Canadian dollar terms for the remaining contract period that ends in March 2020. This is materially lower than the average of 43% of WTI in Canadian dollars that was realized in 2018.

Capital expenditures for the third quarter of 2019 totaled $32.8 million and included $22.4 million for facilities (primarily the Nig Gas Plant), $3.1 million to drill an acid gas injection well at Nig, $4.5 million to complete the acid gas injection well and finish completion operations on a four-well pad at Nig, and $3.6 million for equipping and pipelines. These expenditures were slightly offset by a minor land disposition, which brought in $1.1 million of proceeds. During the third quarter no new wells were brought on stream. At quarter end the Company had an inventory of nine (8.5 net) standing horizontal wells that had not started producing which includes five (4.5 net) completed wells. Fourth quarter production is forecast to be 22,000 to 24,000 Boe per day. As planned, capital expenditures in the third quarter of 2019 outpaced funds flow due to spending on construction activities relating to the sour gas plant at Nig. It is anticipated that for the remainder of the year planned capital expenditures will also be in excess of funds flow with the difference expected to be financed with the Company's credit facility.

Field operating netback per Boe for the third quarter of 2019 amounted to $6.84, a decrease compared to $14.69 in the same period of 2018, while funds flow per Boe decreased to $7.00 from $11.81 in the same period of 2018. The reduction in the field operating netback and the funds flow netback versus the comparative period was primarily a result of lower realized pricing for both natural gas and liquids.

Total debt, including working capital deficiency, at quarter end amounted to $123 million, which increased by approximately $20 million from the end of the immediately preceding quarter as capital expenditures outpaced funds flow given the build-out of the Nig Gas Plant. With approximately $70 million of unused credit capacity, Storm retains considerable financial flexibility to manage its capital expenditure program including completing construction of the Nig Gas Plant, which remains scheduled for start-up in January 2020.

Subsequent to quarter end, the Company's bank syndicate, upon completion of a mid-year review, confirmed Storm's bank facility at $205 million, which had $107 million drawn at the end of the third quarter.

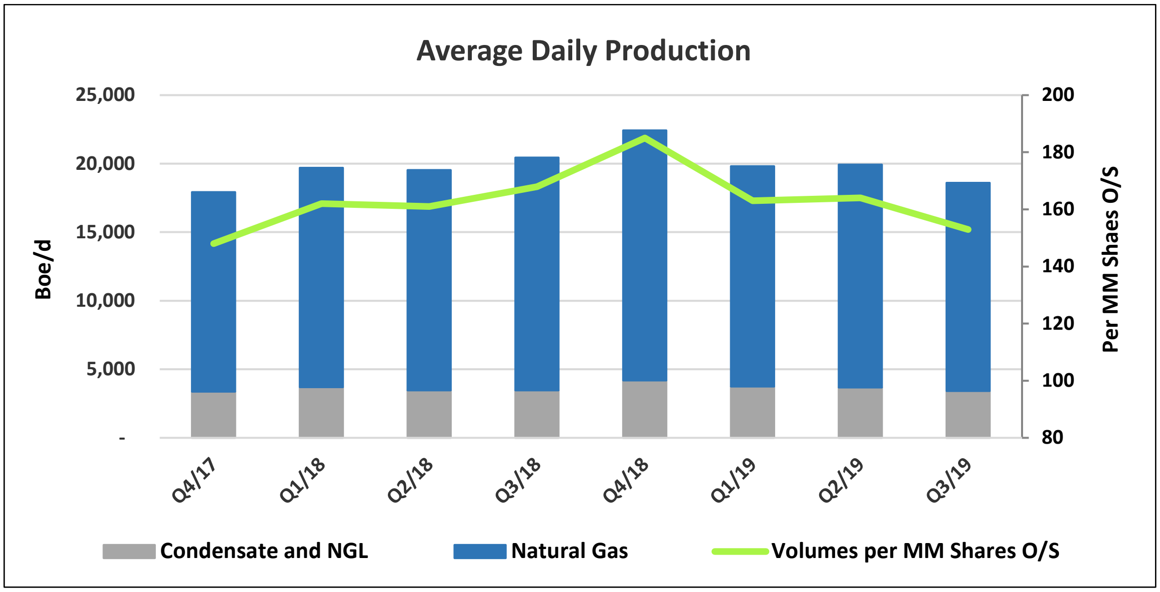
Production and Revenue

Average Daily Production

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Quarter-Over-Quarter Change	Nine Months to Sept. 30, 2019	Nine months to Sept. 30, 2018	Year-Over-Year Change
Natural gas (Mcf/d)	91,053	101,905	(11%)	95,013	98,154	(3%)
Condensate (Bbls/d)	1,856	2,059	(10%)	2,044	2,035	0%
NGL (Bbls/d)	1,564	1,412	11%	1,563	1,506	4%
Total (Boe/d)	18,596	20,455	(9%)	19,443	19,900	(2%)
Natural gas weighting	82%	83%		81%	82%	
Condensate weighting	10%	10%		11%	10%	
NGL weighting	8%	7%		8%	8%	

Production for natural gas, condensate and NGL for the third quarter of 2019 was 9% lower compared to the third quarter of 2018. Similar to the first half of 2019, the third quarter was affected by a third-party outage at the McMahon Gas Plant (14 days) which reduced production by approximately 2,400 Boe per day in the period. In addition to the unplanned outage in the third quarter of 2019, production was also voluntarily curtailed at times in response to weak natural gas pricing at Station 2.

When comparing the first nine months of 2019 to the same period of 2018, production was comparable despite being negatively affected by outages. Of the 43 days of outages, 12 days related to planned outages while the remaining 31 days of outages were unplanned. These outages reduced production by approximately 2,700 Boe per day for the nine months ended September 30, 2019.



Daily production per million shares outstanding at the end of the third quarter averaged 153 Boe per day, compared to 168 Boe per day for the third quarter of 2018, a decrease of 9%.

Revenue from Product Sales[1]

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Natural gas	$ 20,252	$ 30,136	$ 82,652	$ 90,879
Condensate	10,836	16,098	36,726	45,815
NGL	329	5,019	5,373	14,765
Total	$ 31,417	$ 51,253	$ 124,751	$ 151,459
% of Total Revenue by Product Type				
Natural gas	64%	59%	66%	60%
Condensate and NGL	36%	41%	34%	40%
Total	100%	100%	100%	100%

(1) Before realized gains and losses on risk management contracts and including natural gas purchased and sold to meet marketing commitments during outages.

Revenue from product sales for the third quarter of 2019 decreased by 39% when compared to the third quarter of 2018 primarily as a result of the Company's average realized price decreasing by 33%. For the nine month periods, revenue from product sales decreased 18% year over year primarily due to the Company's average realized price decreasing by 16%.

The contribution of condensate and NGL to total revenue from product sales has decreased to 36% and 34% for the three and nine months ended September 30, 2019, respectively (three and nine months ended September 30, 2018 – 41% and 40%, respectively) given the decline in NGL prices year over year. For the three months ended September 30, 2019 NGL prices have decreased by 94% while for the nine months ended September 30, 2019 NGL prices have decreased by 65%.

A reconciliation of year-over-year revenue changes for the three month periods ending September 30 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q3 2018	$ 30,136	$ 16,098	$ 5,019	$ 51,253
Effect of changes in production	(3,209)	(1,587)	542	(4,254)
Effect of changes in average product prices	(6,675)	(3,675)	(5,232)	(15,582)
Revenue from product sales – Q3 2019	$ 20,252	$ 10,836	$ 329	$ 31,417

A reconciliation of year-over-year revenue changes for the nine month periods ending September 30 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q3 2018 YTD	$ 90,879	$ 45,815	$ 14,765	$ 151,459
Effect of changes in production	(2,908)	200	563	(2,145)
Effect of changes in average product prices	(5,319)	(9,289)	(9,955)	(24,563)
Revenue from product sales – Q3 2019 YTD	$ 82,652	$ 36,726	$ 5,373	$ 124,751

Average Selling Prices(1)

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Natural gas – Mcf	$ 2.42	$ 3.21	$ 3.19	$ 3.39
Condensate – Bbl	$ 63.45	$ 84.97	$ 65.81	$ 82.46
NGL – Bbl	$ 2.29	$ 38.64	$ 12.59	$ 35.92
Per Boe	$ 18.36	$ 27.24	$ 23.50	$ 27.88

(1) Before realized gains and losses on risk management contracts.

On a per-Boe basis, the Company's average realized price for the three months ended September 30, 2019 decreased by 33% compared to the same period of 2018, with the decrease driven by lower natural gas, NGL and condensate pricing. As previously communicated, Storm's NGL price for the April 2019 to March 2020 contract year was expected to be approximately 5% to 10% of WTI. The Company's NGL price for the third quarter of 2019 was 3% of WTI which was below expectations primarily because of lower propane pricing which hit a low for the year in August as a result of an oversupply in Western Canada. The decrease in natural gas pricing is primarily due to a reduction in prices at Chicago and Station 2.

On a per-Boe basis, the Company's average realized price for the first nine months of 2019 decreased by 16% when compared to the first nine months of 2018, primarily driven by decreases in NGL, condensate and natural gas pricing.

Benchmark Prices

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Natural gas				
Chicago monthly index (US$/Mmbtu)	2.03	2.75	2.60	2.87
Chicago daily index (US$/Mmbtu)	2.10	2.77	2.48	2.79
Sumas (US$/Mmbtu)	2.08	2.01	3.66	2.04
AECO monthly index (Cdn$/GJ)	0.99	1.28	1.32	1.34
AECO daily index (Cdn$/GJ)	0.87	1.13	1.44	1.41
Station 2 (Cdn$/GJ)	0.63	1.24	0.81	1.37
Crude Oil				
WTI (US$/Bbl)	56.45	69.50	57.06	66.75
WTI (Cdn$/Bbl)	74.57	90.85	75.84	86.01
Edmonton condensate (Cdn$/Bbl)	68.70	87.35	70.21	85.31
Exchange rate (US$/Cdn$)	0.76	0.77	0.75	0.78

Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate and the higher heat content of the Company's natural gas will increase the per-Mcf price.

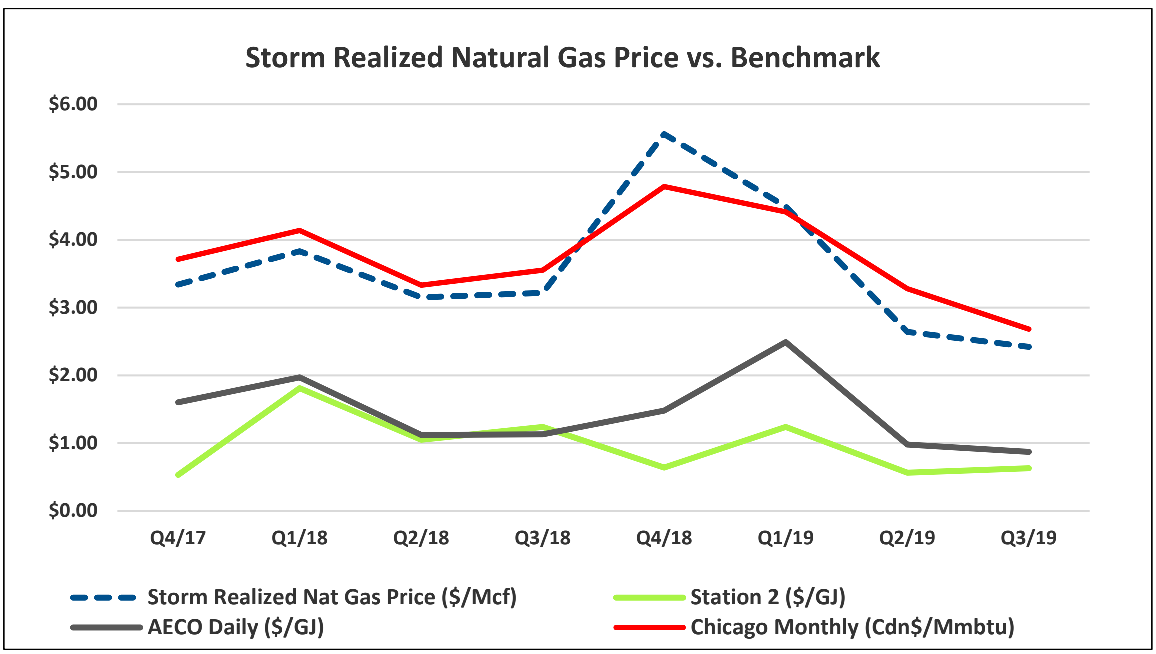
In October 2018, a pipeline rupture occurred on the Enbridge T-south line which reduced pipeline capacity. This has increased volatility in pricing for both Station 2 (lower) and Sumas (higher). During the first quarter of 2019, the monthly

Sumas index price averaged US$6.81 per Mmbtu resulting in increased revenue for Storm which was offset by increased hedging losses on Storm's sales at Sumas. Sumas pricing in the third quarter of 2019 normalized to US$2.08 per Mmbtu with decreased demand in the Pacific Northwest. It is anticipated that the Enbridge T-south line will be returning to full capacity in November 2019.

US natural gas prices have trended lower in 2019, particularly in the third quarter, due to increasing supply and reduced demand through the summer and into shoulder season.

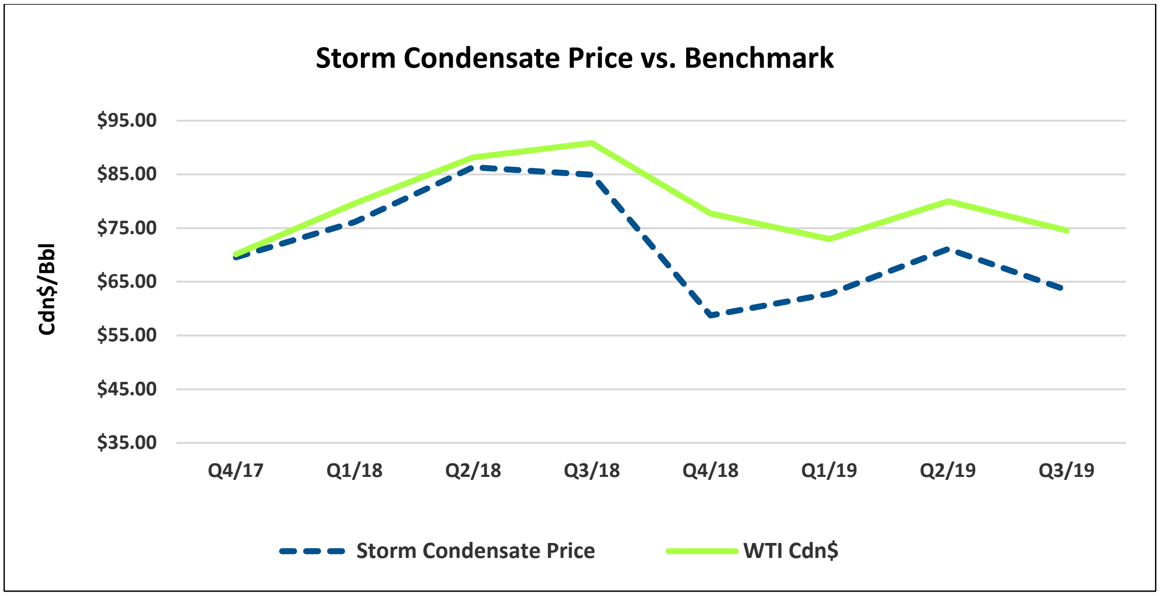
WTI crude oil pricing, on which a large part of the Company's condensate and NGL revenue is based, declined 19% from US$69.50 per barrel during the third quarter of 2018 to US$56.45 per barrel for the third quarter of 2019 due to global trade tensions continuing to affect international economies and lower oil demand forecasts, partially offset by geopolitical tensions in the Middle East affecting the stability of oil supplies. In addition to the decrease in the WTI price was the widening of the Edmonton condensate differential from a discount of US$2.68 per barrel in the third quarter of 2018 to a discount of US$4.44 per barrel for the third quarter of 2019. The condensate differential remained relatively stable in the third quarter of 2019 relative to the first six months of 2019 and is expected to settle at an approximate US$4.00 per barrel discount to WTI in the fourth quarter of 2019.

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Chicago monthly index price	33%	37%	35%	39%
Chicago daily index price	29%	24%	23%	25%
AECO daily index price	10%	2%	11%	3%
Station 2 daily spot price	17%	20%	18%	16%
Sumas index price	11%	12%	11%	12%
Alliance Transfer Point ("ATP")	-	5%	2%	5%
Total	100%	100%	100%	100%

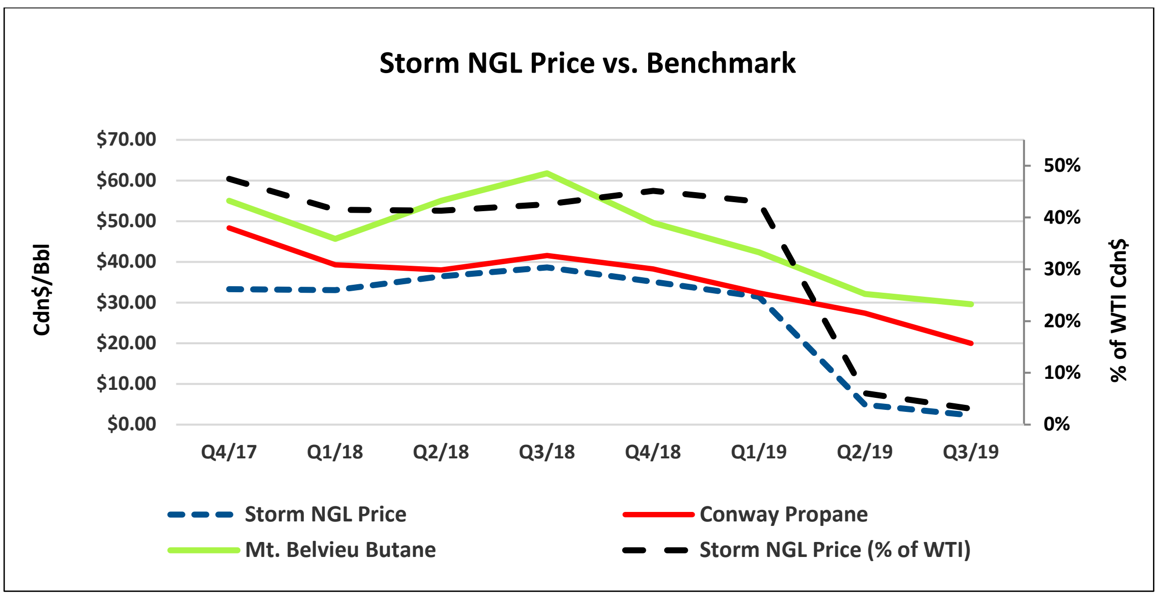


As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 270% higher than Station 2 pricing in the third quarter of 2019. A significant contributor to Storm's realized natural gas price of $2.42 per Mcf in the third quarter of 2019 was selling approximately 70% of the Company's natural gas into the Chicago and Sumas markets, which have higher relative pricing than AECO and Station 2.

The effect of the higher realized natural gas price on the Company's funds flow is partially offset by higher transportation costs.



Storm's realized condensate price for the third quarter of 2019 decreased by 25% from the third quarter of 2018 as a result of the decrease in the WTI price combined with a slight widening of the WTI-Edmonton condensate differential from the third quarter of 2018 to the third quarter of 2019.



Storm's realized price for NGL, excluding condensate, in the third quarter of 2019 decreased by 94% relative to the same period of 2018. When comparing the first nine months of 2019 to the same period of 2018, the realized price for NGL, excluding condensate, decreased by 65%. The decrease in realized NGL prices for both of the aforementioned periods was primarily due to lower contracted butane pricing as a result of elevated supply levels, lower propane pricing and weaker WTI pricing period over period.

Storm's NGL price net of transportation for the remainder of the year is anticipated to be approximately 5% to 10% of WTI in Canadian dollar terms for the contract period that commenced in April 2019 and ends in March 2020, as propane pricing is expected to improve as a result of seasonal demand.

Risk Management

	Three Months Ended September 30, 2019		Three Months Ended September 30, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ 1,914	$ (1,659)	$ (563)	$ (2,069)
Liquids(1)	897	395	(2,690)	(303)
Interest rate	-	(13)	-	-
Gain (loss) on risk management contracts	$ 2,811	$ (1,277)	$ (3,253)	$ (2,372)

	Nine Months Ended September 30, 2019		Nine Months Ended September 30, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (8,174)	$ 8,303	$ 2,087	$ (12,529)
Liquids(1)	984	(4,652)	(6,903)	(5,589)
Interest rate	1	(111)	-	-
Gain (loss) on risk management contracts	$ (7,189)	$ 3,540	$ (4,816)	$ (18,118)

(1) Liquids includes field condensate, plant pentanes, butane and propane.

Although the Company has no crude oil production, condensate and a portion of the NGL stream is priced with reference to WTI and, as a result, the Company enters into crude oil risk management contracts to hedge liquids prices.

The realized gains and losses on risk management contracts consists of the portion of contracts that have settled in cash during the reporting period. The realized loss of $7.2 million for the nine months ended September 30, 2019 is primarily due to higher pricing at Chicago and Sumas during the first quarter of 2019.

The unrealized gain (loss) on risk management contracts is a non-cash charge representing the change in the mark-to-market position of remaining unexpired contracts at the end of the period.

Royalties

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Charge (recovery) for period	$ (332)	$ 1,934	$ 4,902	$ 6,938
Percentage of revenue from product sales	(1.1%)	3.8%	3.9%	4.6%
Per Boe	$ (0.19)	$ 1.03	$ 0.92	$ 1.28

Royalties, as a percentage of revenue from product sales, decreased in the third quarter of 2019 compared to the same period in 2018 primarily due to receipt of $1.9 million in infrastructure royalty credits in the third quarter of 2019 ($0.8 million received in the third quarter of 2018) and lower commodity prices, partially offset by a decrease of wells benefitting from the BC Deep Well Royalty Program. Storm receives royalty credits on qualifying wells through the BC Deep Well Royalty Credit Program which reduces the royalty rate on new horizontal wells to 6% for approximately two years. In the third quarter of 2019, 26 wells qualified for the 6% royalty rate compared to 36 wells in the third quarter of 2018.

Royalties, as a percentage of revenue from product sales, decreased in the nine months ended September 30, 2019 compared to the same period in 2018 primarily due to receipt of infrastructure royalty credits of $3.5 million to date in 2019 (credits of $1.4 million received in 2018) and lower commodity prices, partially offset by a decrease in the number of wells benefitting from the BC Deep Well Royalty Program.

Storm has remaining infrastructure royalty credits of $0.8 million that will reduce future royalties. Storm has been granted approval for infrastructure royalty credits of $6.2 million relating to the construction of the Nig Gas Plant, which is expected to be completed in early 2020. Future royalty payments are dependent on commodity prices and production levels from individual wells and thus the timing to receive future royalty credits cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary as these credits are earned.

Production Costs

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Charge for period	$ 10,068	$ 10,419	$ 31,611	$ 29,972
Per Boe	$ 5.88	$ 5.54	$ 5.96	$ 5.52

Total production costs for the third quarter of 2019 decreased 3% when compared to the third quarter of 2018. Total production costs increased by 5% in the first nine months of 2019 when compared to the same period of 2018. The decrease in total production costs for the third quarter of 2019 compared to the third quarter of 2018 is primarily due to lower gas processing costs, corresponding to reduced production volumes in 2019. The increase in total production costs for the nine months ended September 30, 2019 compared to the same period in 2018 was primarily due to fixed costs incurred during unplanned outages at the McMahon Gas Plant and an increase in the BC carbon tax.

On a per-Boe basis, production costs increased by 6% and 8% in the three and nine months ended September 30, 2019 compared to the same periods of 2018. Production costs on a per-Boe basis increased due to incurring fixed costs during unplanned outages at the McMahon Gas Plant.

Carbon Tax

With the majority of the Company's operations located in British Columbia, the Company is subject to the British Columbia Carbon Tax Act. Storm pays carbon tax on fuel used in the Company's own facilities as well as on natural gas volumes processed at third-party facilities. The following table outlines the total carbon taxes (direct and indirect) that are included as a component of the aforementioned production costs.

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Charge for period	$ 1,368	$ 1,318	$ 4,196	$ 3,848
Per Boe	$ 0.80	$ 0.70	$ 0.79	$ 0.71

Transportation Costs

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Charge for period	$ 9,981	$ 11,257	$ 30,995	$ 32,277
Per Boe	$ 5.83	$ 5.98	$ 5.84	$ 5.94

Transportation costs include pipeline tariffs for natural gas sold at various price points, as well as trucking costs and pipeline tariffs for wellhead condensate. Natural gas sales volumes destined for Chicago and markets across North America have higher per-unit transportation costs, but obtain higher sales prices which offsets the higher pipeline tariffs.

Transportation costs for the third quarter of 2019 decreased by 11% and by 3% on a per-Boe basis when compared to the third quarter of 2018 primarily due to lower production levels coupled with partially mitigating the transportation commitment on the Alliance Pipeline during the 14-day unplanned outage at the McMahon Gas Plant in the third quarter of 2019. Transportation costs for the first nine months of 2019 decreased by 4% and 2% on a per-Boe basis when compared to the same period in 2018 due to selling less natural gas to Chicago using interruptible capacity on the Alliance Pipeline, partially offset by incurring fixed costs for unused firm transportation during outages.

Field Netbacks

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

	Three Months to September 30, 2019			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.42	$ 63.45	$ 2.29	$ 18.36
Royalties	0.19	(7.12)	(0.11)	0.19
Production costs	(1.20)	-	-	(5.88)
Transportation costs	(1.10)	(4.47)	-	(5.83)
Field operating netback	$ 0.31	$ 51.86	$ 2.18	$ 6.84
Realized gain (loss) on risk management contracts	0.23	2.78	2.93	1.64
Field operating netback including hedging	$ 0.54	$ 54.64	$ 5.11	$ 8.48

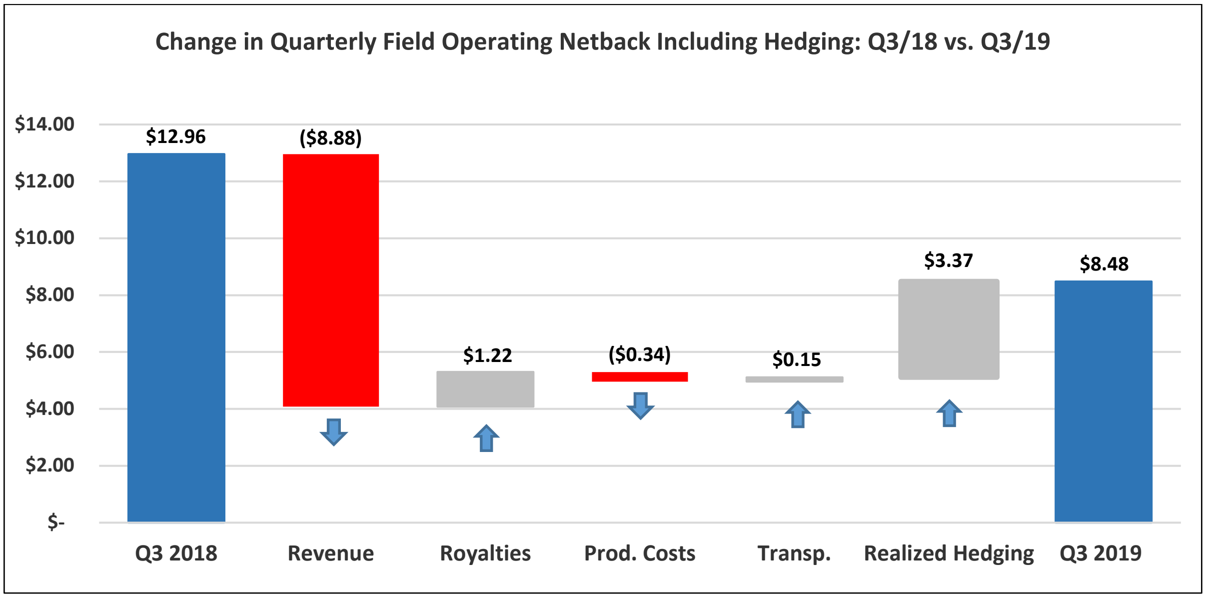
	Three Months to September 30, 2018			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.21	$ 84.97	$ 38.64	$ 27.24
Royalties	(0.01)	(7.40)	(3.70)	(1.03)
Production costs	(1.11)	-	-	(5.54)
Transportation costs	(1.08)	(5.78)	-	(5.98)
Field operating netback	$ 1.01	$ 71.79	$ 34.94	$ 14.69
Realized gain (loss) on risk management contracts	(0.06)	(13.92)	(0.42)	(1.73)
Field operating netback including hedging	$ 0.95	$ 57.87	$ 34.52	$ 12.96

	Nine Months to September 30, 2019			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.19	$ 65.81	$ 12.59	$ 23.50
Royalties	0.01	(7.85)	(1.70)	(0.92)
Production costs	(1.22)	-	-	(5.96)
Transportation costs	(1.09)	(5.01)	(0.08)	(5.84)
Field operating netback	$ 0.89	$ 52.95	$ 10.81	$ 10.78
Realized gain (loss) on risk management contracts	(0.32)	0.16	2.09	(1.35)
Field operating netback including hedging	$ 0.57	$ 53.11	$ 12.90	$ 9.43

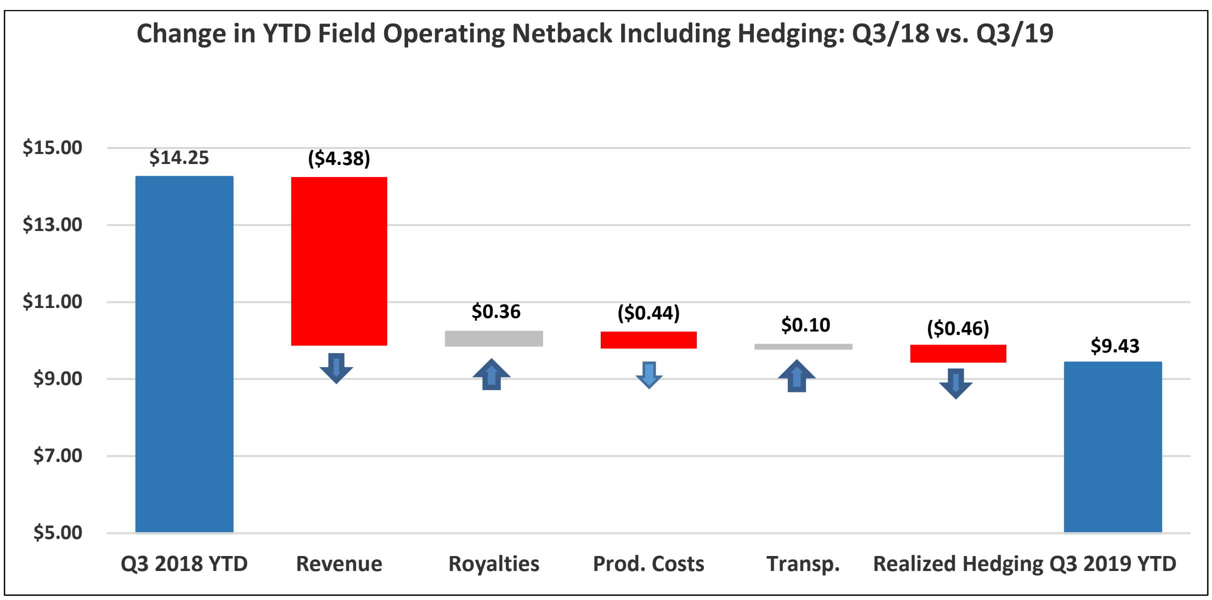
	Nine Months to September 30, 2018			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.39	$ 82.46	$ 35.92	$ 27.88
Royalties	(0.06)	(7.30)	(3.31)	(1.28)
Production costs	(1.12)	-	-	(5.52)
Transportation costs	(1.10)	(5.15)	-	(5.94)
Field operating netback	$ 1.11	$ 70.01	$ 32.61	$ 15.14
Realized gain (loss) on risk management contracts	0.08	(12.41)	(0.01)	(0.89)
Field operating netback including hedging	$ 1.19	$ 57.60	$ 32.60	$ 14.25

(1) Production costs of condensate and NGL are included within natural gas costs.
(2) Realized gains and losses on crude oil contracts are included within the condensate netback.

The field operating netback for the third quarter of 2019 decreased by 53% (35% decrease after hedging) compared to the third quarter of 2018.



The field operating netback for the first nine months of 2019 decreased by 29% (34% decrease after hedging) compared to the first nine months of 2018.



General and Administrative Costs

	Three Months to Sept. 30, 2019		Three Months to Sept. 30, 2018		Nine Months to Sept. 30, 2019		Nine Months to Sept. 30, 2018	
Charge for period – before recoveries	$	1,728	$	1,740	$	6,831	$	6,095
Overhead recoveries		(369)		(500)		(1,393)		(1,111)
Charge for period – net of recoveries	$	1,359	$	1,240	$	5,438	$	4,984
Per Boe	$	0.79	$	0.66	$	1.02	$	0.92

General and administrative costs before recoveries for the third quarter of 2019 were broadly in line with the third quarter of 2018. General and administrative costs before recoveries for the nine months ended September 30, 2019 increased by 12% compared to the same period of 2018 primarily due to higher compensation costs and the payout of the annual employee performance bonus after year-end results were finalized.

As a result of the change in lease accounting effective January 1, 2019, general and administrative costs in the third quarter of 2019 are lower by $0.1 million related to the office lease.

Fluctuations in overhead recoveries are in response to the amount and type of field capital expenditures incurred.

Net general and administrative costs on a per-Boe measure for the third quarter of 2019 were 20% higher than the third quarter of 2018, and 11% higher when comparing the first nine months of 2019 to the same period of 2018. Generally, the Company's general and administrative cost structure is predictable year to year and variability in per-Boe metrics is due to changes in production volumes.

Interest and Finance Costs

	Three Months to Sept. 30, 2019		Three Months to Sept. 30, 2018		Nine Months to Sept. 30, 2019		Nine Months to Sept. 30, 2018	
Charge for period(1)	$	1,215	$	923	$	3,648	$	3,321
Average interest rate(2)		5.0%		4.6%		5.1%		4.8%
Per Boe	$	0.71	$	0.49	$	0.69	$	0.61

(1) Includes lease interest.
(2) Includes financing and standby fees; excludes lease interest.

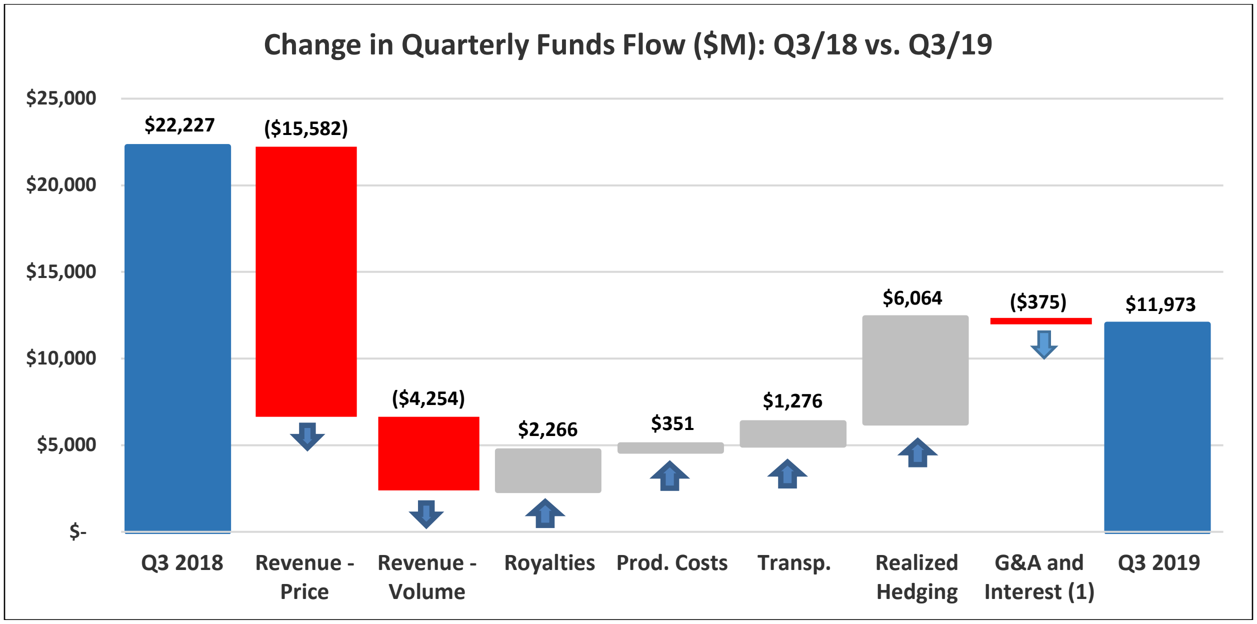
The interest rate on the Company's bank facility is based on bankers' acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the third quarter and first nine months of 2019 increased by 32% and 10%, respectively, compared to the same periods of 2018 as a result of higher market interest rates combined with higher average bank borrowings which are used to fund capital expenditures.

Funds Flow

	Three Months to Sept. 30, 2019		Three Months to Sept. 30, 2018		Nine Months to Sept. 30, 2019		Nine Months to Sept. 30, 2018	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$11,973	$0.10	$22,227	$0.18	$41,080	$0.34	$69,151	$0.57

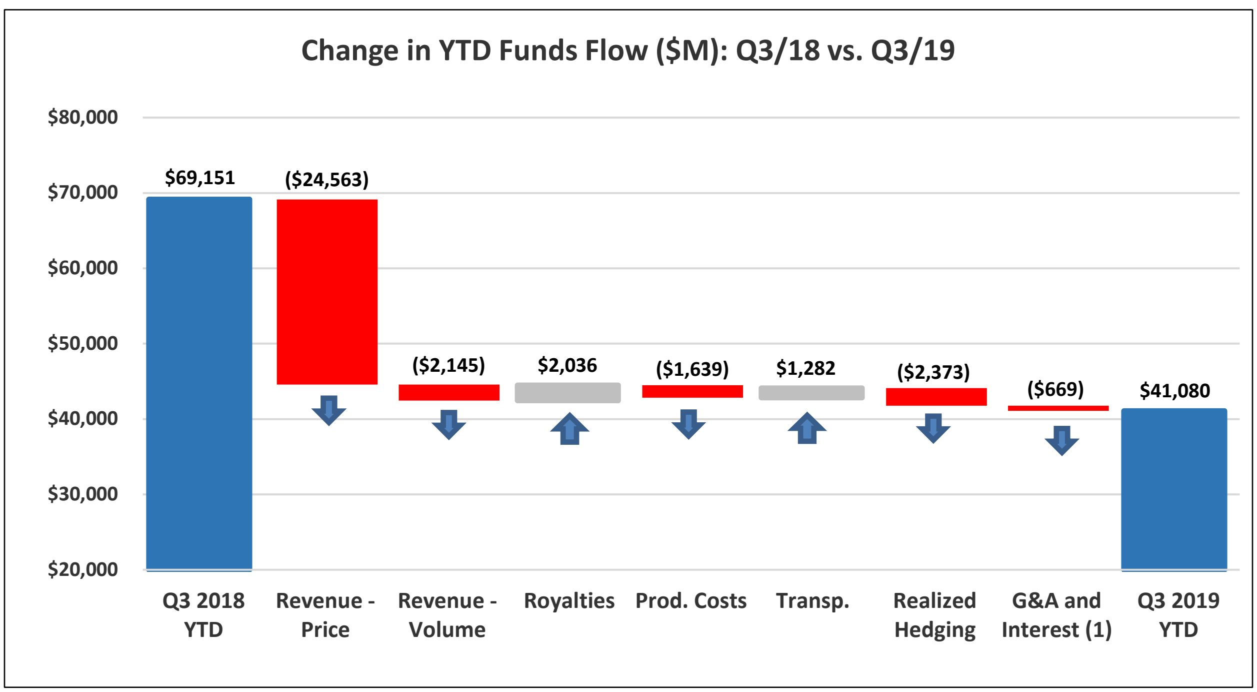
Funds flow, a measure that is not defined under IFRS, is cash generated from operating activities before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies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



(1) Excludes lease interest.

Lower realized prices was the predominant factor in the decrease in funds flow in the third quarter of 2019 versus the third quarter of 2018.

The cash return on capital employed ("CROCE") over the last 12 months, which is a measurement of the Company's cash profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 15% in the third quarter of 2019 compared to 21% in the third quarter of 2018.



(1) Excludes lease interest.

Funds flow for the first nine months of 2019 decreased by 41% from the first nine months of 2018. Funds flow was negatively affected by weaker realized pricing.

Share-Based Compensation

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Charge for period	$ 648	$ 823	$ 1,808	$ 2,289
Per Boe	$ 0.38	$ 0.44	$ 0.34	$ 0.42

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 decreased by 21% in the three and nine months ended September 30, 2019 compared to the same periods of 2018. The decrease in share-based compensation in both the three and nine month periods is primarily attributable to a lower option fair valuation associated with options granted during 2018.

Depletion and Depreciation

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Depletion	$ 7,604	$ 10,057	$ 23,496	$ 29,818
Depreciation	1,946	1,715	5,754	5,000
Charge for period	$ 9,550	$ 11,772	$ 29,250	$ 34,818
Per Boe	$ 5.58	$ 6.26	$ 5.51	$ 6.41

Depletion and depreciation decreased by 19% in the third quarter of 2019 compared to the same quarter of 2018. Comparing the first nine months of 2019 with the same period in 2018, depletion and depreciation decreased by 16%. The quarterly and year-to-date per-Boe decreases in depletion correspond to lower finding and development costs at Umbach.

Income Taxes

In May 2019, the Government of Alberta substantively enacted a reduction in the provincial corporate tax rate from 12% to 8% over a four-year period.

The Company did not incur any cash tax expense in the three and nine months ended September 30, 2019, nor does it expect to pay any cash tax in the remainder of 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

Deferred income taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. For the three and nine months ended September 30, 2019, the Company recognized a deferred income tax expense of $0.3 million and $3.5 million, respectively, as a result of $0.3 million and $11.9 million of net income before taxes, respectively. As at September 30, 2019, the Corporation had a deferred income tax liability of $7.9 million.

Tax Pools	As at September 30, 2019	Maximum Annual Deduction
Canadian oil and gas property expense	$ 44,000	10%
Canadian development expense	121,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	127,000	20% - 100%
Operating losses	182,000	100%
Other	1,000	20% - 100%
Total	$ 498,000	

Net Income (Loss)

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Net income (loss)	$ (64)	$ 7,174	$ 8,407	$ 13,253
Per basic and diluted share	$ (0.00)	$ 0.06	$ 0.07	$ 0.11

The mark-to-market valuation of risk management contracts resulted in a considerable distortion on reported net income (loss) for the three and nine months ended September 30, 2019 relative to the comparable periods in 2018. The mark-to-market valuation of risk management contracts amounted to an unrealized loss of $1.3 million for the three months ended September 30, 2019 and an unrealized gain of $3.5 million for the nine months ended September 30, 2019. This compares to unrealized losses for the three and nine months ended September 30, 2018 of $2.4 million and $18.1 million, respectively.

Excluding unrealized gains and losses on risk management contracts, the decrease in net income in the three and nine months ended September 30, 2019 compared to the same periods of 2018 is primarily attributable to the weakened commodity pricing environment driving decreased revenue.

The return on capital employed ("ROCE") over the last 12 months, which is a measurement of the Company's income profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 9% in the third quarter of 2019 compared to 6% in the third quarter of 2018, although as mentioned above is distorted by unrealized gains and losses on the Company's risk management contracts.

Corporate Netbacks

($/Boe)	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Revenue from product sales	18.36	27.24	23.50	27.88
Realized gain (loss) on risk management contracts	1.64	(1.73)	(1.35)	(0.89)
Royalties	0.19	(1.03)	(0.92)	(1.28)
Production	(5.88)	(5.54)	(5.96)	(5.52)
Transportation	(5.83)	(5.98)	(5.84)	(5.94)
General and administrative	(0.79)	(0.66)	(1.02)	(0.92)
Interest and finance costs	(0.69)	(0.49)	(0.67)	(0.61)
Funds flow	7.00	11.81	7.74	12.72
Share-based compensation	(0.38)	(0.44)	(0.34)	(0.42)
Depletion, depreciation and accretion	(5.65)	(6.33)	(5.58)	(6.48)
Lease interest	(0.02)	-	(0.02)	-
Exploration and evaluation costs expensed	-	-	(0.21)	(0.05)
Unrealized revaluation gain (loss) on investments	(0.05)	0.02	(0.02)	-
Unrealized gain (loss) on risk management contracts	(0.75)	(1.26)	0.67	(3.33)
Deferred income tax expense	(0.19)	-	(0.65)	-
Net income (loss)	(0.04)	3.80	1.59	2.44

INVESTMENT AND FINANCING

Financial Resources and Liquidity

As at September 30, 2019, the Company had an extendible revolving credit facility in the amount of $205 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 29, 2020, 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 in full one year later. In the event that the lenders reduce the borrowing base below the amount drawn, the Company would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. Interest is paid on the utilized portion of the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company.

At September 30, 2019, debt including working capital deficiency amounted to $123.3 million, representing approximately 60% of the available credit facility.

As at September 30, 2019, the Company had issued letters of credit in the amount of $10.0 million (December 31, 2018 - $7.6 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

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

In the third quarter of 2019, the Company incurred capital expenditures of $32.8 million compared to $21.8 million in the third quarter of 2018.

In the first nine months of 2019, the Company incurred capital expenditures of $72.9 million (first nine months of 2018 - $47.7 million) primarily related to costs incurred in constructing the Nig Gas Plant, drilling and completing an acid gas injection well, as well as drilling and completion activities on a four-well pad at Nig.

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Land and seismic	$ 250	$ 1,878	$ 1,785	$ 2,803
Drilling	3,123	289	14,431	289
Completions	4,529	10,798	12,483	19,853
Facilities	22,420	4,690	40,287	10,693
Equipping and pipelines	3,585	4,006	4,914	12,599
Recompletions and workovers	6	35	55	772
Property acquisition and administrative assets	11	149	58	654
Total field capital expenditures	$ 33,924	$ 21,845	$ 74,013	$ 47,663
Proceeds on disposition of undeveloped land	(1,083)	-	(1,083)	-
Total capital expenditures	$ 32,841	$ 21,845	$ 72,930	$ 47,663

Net capital investment was allocated as follows:

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Exploration and evaluation	$ (819)	$ 1,878	$ 716	$ 2,991
Property and equipment	33,660	19,967	72,214	44,672
Total capital expenditures	$ 32,841	$ 21,845	$ 72,930	$ 47,663

Decommissioning Liability

The Company's decommissioning liability of $32.8 million 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 and inflated amount of the liability at September 30, 2019 was $46.5 million (December 31, 2018 - $43.2 million).

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 office space and field equipment;
- rental obligations for accommodation, office equipment and automotive equipment;
- banking agreements; and
- risk management contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The remaining aggregate commitment approximates $5.0 million over seven years. In addition, as at the date of this report, the Company has transportation and processing commitments valued at a total of approximately $419.2 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 2019 appears below.

Apart from minimal capital expenditures in the second quarter of 2018, the first and third quarter results for 2018 were relatively consistent in terms of capital expenditures, production and funds flow, supported by stable Chicago natural gas prices and materially stronger liquids pricing. Capital expenditures were increased in the fourth quarter of 2018 primarily to include deposits on long-lead-time equipment for the sour gas plant at Nig. In response to strong US based pricing, production was increased in the fourth quarter leading to strong funds flow generation in the period. With funds flow outpacing capital expenditures, debt including working capital was reduced by approximately $15 million over the course of the year.

An unplanned outage in the first quarter of 2019 resulted in approximately 19,500 Boe per day of the Company's production being shut in for 17 days. This had a notable effect on revenue, costs, funds flow and net income for the period. Capital expenditures in the first quarter of 2019 approximated funds flow resulting in marginal movement in debt including working capital deficiency.

In the second quarter of 2019, weaker pricing across all products resulted in lower revenue, while a planned Alliance Pipeline outage resulted in increased costs as fixed transportation tolls were incurred without associated revenue. Debt including working capital deficiency increased to $102.3 million as spending on the Nig Gas Plant progressed.

The third quarter of 2019 was affected negatively by an unplanned 14-day outage at the McMahon Gas Plant resulting in lower revenues. The debt including working capital deficiency rose to $123.3 million as construction of the Nig Gas Plant continued as planned.

		2019					2018	2017
($000s unless otherwise stated)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue from product sales	31,417	37,568	55,766	74,799	51,253	48,104	52,102	43,506
Funds flow	11,973	12,590	16,517	30,941	22,227	23,405	23,519	21,323
Per share – basic and diluted ($)	0.10	0.10	0.14	0.25	0.18	0.19	0.19	0.18
Net income (loss)	(64)	7,864	607	26,810	7,174	(2,815)	8,894	8,624
Per share – basic and diluted ($)	(0.00)	0.06	0.00	0.22	0.06	(0.02)	0.07	0.07
Net capital expenditures	32,841	23,145	16,944	37,100	21,845	2,918	22,900	26,126
Average daily production (Boe)	18,596	19,923	19,823	22,432	20,455	19,529	19,708	17,936
Debt including working capital deficiency[1]	123,342	102,268	91,585	91,020	84,648	85,073	105,585	106,124

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.

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 November 12, 2019 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 including prices as outlined in 2019 and 2020 guidance;
- future average production volumes in the fourth quarter of 2019 and annual production for 2019, along with production volumes by commodity;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2019 guidance;
- future reduction to corporate operating costs to approximately $4.25 per Boe with the start-up of the Nig Gas Plant, along with the forecast operating cost for the Nig Gas Plant of less than $2.00 per Boe and total sales from the Nig Gas Plant of approximately 10,500 Boe per day (27% liquids);
- future value of unrealized risk management contracts including the estimated hedging loss as outlined in 2019 guidance;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2019 capital expenditure program including 2019 capital investment of $105 to $110 million and total cost of approximately $86 million for the Nig Gas Plant;
- the Nig Gas Plant adding $15 to $20 million to 2020 funds flow depending on liquids pricing;
- estimated capital investment for 2020 of $75 to $90 million and that this is expected to be approximately equal to funds flow;
- fourth quarter 2019 production of 22,000 to 24,000 Boe per day (4,000 to 4,300 barrels per day of liquids) and fourth quarter capital investment of $32 to $37 million;
- future expansion plans at Fireweed including expansion of the compression facility to 100 Mmcf per day, and 2020 net capital expenditures of $35 million to $50 million;
- future growth plans through 2020 including timing for the start-up of the Nig Gas Plant and the Fireweed field compression facility;
- future cost of the Fireweed compression facility, including access road and sales pipeline, of $38 million along with field condensate-gas ratios that are forecast to be significantly higher than Umbach;
- future production levels of 27,000 to 30,000 Boe per day (5,700 to 6,300 barrels per day of liquids) in the fourth quarter of 2020;
- average annual production in 2020 of 24,000 to 26,000 Boe per day, representing a 25% increase from 2019 with liquids production increasing approximately 45%;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including the amounts outlined in 2019 guidance and 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;
- 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 exiting 2019 below 2.0 times annualized fourth quarter funds flow with this ratio decreasing further in 2020 after start-up of the Nig Gas Plant;
- availability and use of credit facilities including approximately $70 million of unused credit capacity at quarter end;
- 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 along with the expectation to not pay any cash tax in 2019 or 2020;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from drilling longer wells, specifically management's estimated 8 and 14 Bcf raw gas type curves for 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 2019 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales allocation in 2019 to Chicago, Sumas, Station 2 and AECO markets and the forecasted NGL price net of transport being approximately 5% to 10% of WTI in Cdn$ for the remaining contract period to March 2020;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- 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 "Business Risks"; "Financial Reporting Update"; and the material assumptions and observations described under the headings "Overview"; "Production and Revenue"; "Risk Management"; "Royalties"; "Production Costs"; "Transportation Costs"; "Field Netbacks"; "General and Administrative Costs"; "Interest and Finance Costs"; "Funds Flow"; "Share-Based Compensation"; "Depletion and Depreciation"; "Exploration and Evaluation Costs Expensed"; "Income Taxes"; "Net Income (Loss)"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Decommissioning Liability"; "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 crude oil in the ratio of six thousand cubic feet of natural gas to one barrel of crude 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", "CROCE", "ROCE" 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

Field operating netbacks and field operating netbacks including hedging are common non-GAAP measurements applied in the crude oil and natural 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.

Debt Including Working Capital Deficiency

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of risk management 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.

($000s unless otherwise stated)	As at Sept. 30, 2019	As at Sept. 30, 2018	As at Sept. 30, 2017
Accounts receivable	14,514	15,100	10,214
Prepaids and deposits	577	845	2,696
Accounts payable and accrued liabilities	(30,969)	(21,848)	(21,207)
Working capital deficiency	15,878	5,903	8,297
Bank indebtedness	107,464	78,745	93,000
Debt including working capital deficiency	123,342	84,648	101,297

CROCE & ROCE

CROCE is non-GAAP financial measure and does not have a standardized meaning under IFRS. CROCE is determined by taking funds flow plus interest and finance costs on a 12-month trailing basis, and dividing it by the average capital employed (shareholders' equity plus debt including working capital deficiency) as presented in the following table.

($000s unless otherwise stated)	Twelve Months Ended September 30, 2019	Twelve Months Ended September 30, 2018
Average debt including working capital deficiency(1)	103,995	92,973
Average shareholders' equity(1)	399,215	367,749
Average capital employed	503,210	460,722
Funds flow	72,021	90,474
Interest and finance costs	4,571	4,426
Funds flow plus interest and finance costs	76,592	94,900
CROCE	15%	21%

(1) The average debt including working capital deficiency and shareholders' equity represent the average of the opening and ending balances as presented on the statement of financial position for the respective period.

ROCE is non-GAAP financial measure and does not have a standardized meaning under IFRS. ROCE is determined by taking net income plus interest and finance costs and deferred income tax expense on a 12-month trailing basis, and dividing it by the average capital employed (shareholders' equity plus debt including working capital deficiency) as presented in the table below.

($000s unless otherwise stated)	Twelve Months Ended September 30, 2019	Twelve Months Ended September 30, 2018
Average debt including working capital deficiency[(1)]	103,995	92,973
Average shareholders' equity[(1)]	399,215	367,749
Average capital employed	503,210	460,722
Net income	35,217	21,877
Interest and finance costs	4,571	4,426
Deferred income tax expense	7,887	-
	47,675	26,303
ROCE	10%	6%

(1) The average debt including working capital deficiency and shareholders' equity represent the average of the opening and ending balances as presented on the statement of financial position for the respective period.

The CROCE and ROCE measures allow management and others to evaluate the Company's capital efficiency and ability to generate profitable returns by measuring the Company's earnings (funds flow and net income) relative to the capital employed in the business.

BUSINESS RISKS

There are a number of risks facing participants in the Canadian crude oil and natural 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 29, 2019 for the year ended December 31, 2018 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2018 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 *Leases* which is effective January 1, 2019 and replaces IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which requires lessees to recognize assets and liabilities for essentially all leases previously classified as operating leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases.

Effective January 1, 2019, the Company adopted IFRS 16 *Leases* using the modified retrospective approach, whereby the cumulative effect of initially applying the standard resulted in the initial recognition of a $3.1 million "Right-of-use asset" with a corresponding increase to "Lease liability" primarily relating to the Company's corporate office lease in Calgary. The modified retrospective approach does not require restatement of prior period comparative financial information and is applied prospectively.

The lease liability was measured at the present value of the remaining lease payments, discounted using the Company's weighted average incremental borrowing rate of approximately 5% on January 1, 2019. The right-of-use asset was measured at amounts equal to the lease liability.

On adoption, the Company used the following practical expedients permitted by the standard:

- Accounted for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases; and
- Accounted for lease payments as an expense for leases for low-value assets.

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company's lease liability as at January 1, 2019:

		Total
Transportation and processing commitments	$	384,707
Office lease		5,773
Commitments as at December 31, 2018		390,480
Less:		
Agreements that do not contain a lease		(384,707)
Non-lease components		(2,082)
Lease liability commitments as at December 31, 2018		3,691
Discounting at incremental borrowing rate of 5%		(597)
Lease liability as at January 1, 2019	$	3,094

Update to Significant Accounting Policies

Lease Liabilities and Right-of-Use Assets

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease liability is recognized at the present value of future lease payments, using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. A corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs. The Company has elected not to recognize leases for short-term leases with a lease term of twelve months or less, or leases for low-value assets. Payments are applied against the lease liability and interest expense is recognized on the lease liability using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures ("DCP") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended September 30, 2019 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

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 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4.

QUARTERY SUMMARIES

Thousands of Cdn$, except volumetric and per-share amounts	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017
FINANCIAL								
Revenue from product sales(1)	31,417	37,568	55,766	74,799	51,253	48,104	52,102	43,507
Funds flow	11,973	12,590	16,517	30,941	22,227	23,405	23,519	21,323
Per share - basic and diluted ($)	0.10	0.10	0.14	0.25	0.18	0.19	0.19	0.18
Net income (loss)	(64)	7,864	607	26,810	7,174	(2,815)	8,894	8,624
Per share - basic and diluted ($)	(0.00)	0.06	0.00	0.22	0.06	(0.02)	0.07	0.07
Cash return on capital employed (“CROCE”)(2)	15%	18%	20%	21%	21%	19%	16%	15%
Return on capital employed (“ROCE”)(2)	9%	11%	8%	10%	6%	4%	7%	10%
Capital expenditures	32,841	23,145	16,944	37,100	21,845	2,918	22,900	26,126
Debt including working capital deficiency(2)(3)	123,342	102,268	91,585	91,020	84,648	85,073	105,585	106,124
Common shares (000s)								
Weighted average - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,853	121,649	121,557	121,557	121,557	121,557
Outstanding end of period - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
OPERATIONS								
(Cdn$ per Boe)								
Revenue from product sales(1)	18.36	20.72	31.26	36.24	27.24	27.07	29.37	26.37
Transportation costs	(5.83)	(5.96)	(5.72)	(5.57)	(5.98)	(6.25)	(5.59)	(5.94)
Revenue net of transportation	12.53	14.76	25.54	30.67	21.26	20.82	23.78	20.43
Royalties	0.19	(0.32)	(2.61)	(0.58)	(1.03)	(1.11)	(1.71)	(0.63)
Production costs	(5.88)	(5.89)	(6.09)	(5.46)	(5.54)	(5.46)	(5.55)	(5.68)
Field operating netback(2)	6.84	8.55	16.84	24.63	14.69	14.25	16.52	14.12
Realized gain (loss) on risk management contracts	1.64	(0.22)	(5.38)	(8.65)	(1.73)	0.31	(1.19)	0.41
General and administrative	(0.79)	(0.68)	(1.60)	(0.55)	(0.66)	(0.69)	(1.42)	(0.94)
Interest and finance costs	(0.69)	(0.71)	(0.61)	(0.45)	(0.49)	(0.71)	(0.64)	(0.67)
Funds flow per Boe	7.00	6.94	9.25	14.98	11.81	13.16	13.27	12.92
Barrels of oil equivalent per day (6:1)	18,596	19,923	19,823	22,432	20,455	19,529	19,708	17,936
Natural gas production								
Thousand cubic feet per day	91,053	97,510	96,537	109,520	101,905	96,426	96,068	87,375
Price (Cdn$ per Mcf)(1)	2.42	2.64	4.49	5.56	3.21	3.15	3.83	3.34
Condensate production								
Barrels per day	1,856	2,081	2,199	2,453	2,059	1,984	2,062	1,914
Price (Cdn$ per barrel)(1)	63.45	71.12	62.77	58.74	84.97	86.33	76.12	69.53
NGL production								
Barrels per day	1,564	1,591	1,534	1,726	1,412	1,473	1,635	1,460
Price (Cdn$ per barrel)(1)	2.29	4.87	31.43	35.09	38.64	36.43	33.05	33.29
Wells drilled (net)	1.0	-	5.0	4.0	-	-	-	7.0
Wells completed (net)	5.0	-	-	2.5	5.0	-	3.0	3.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts and lease liability.

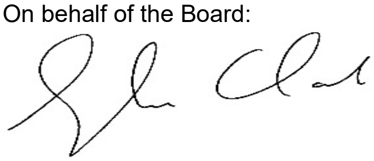
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

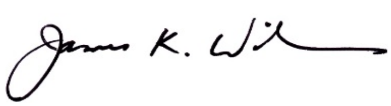
(Canadian $000s) (unaudited)	Notes	September 30, 2019	December 31, 2018
ASSETS			
Current			
Accounts receivable	13	$ 14,514	$ 29,262
Prepaids and deposits		577	853
Risk management contracts	13	1,467	2,341
		16,558	32,456
Exploration and evaluation	4	101,950	102,277
Property and equipment	5	480,092	430,801
Right-of-use asset	3, 8	2,767	-
		$ 601,367	$ 565,534
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current			
Accounts payable and accrued liabilities		$ 30,969	$ 34,359
Risk management contracts	13	-	3,521
		30,969	37,880
Bank indebtedness	6	107,464	86,776
Risk management contracts	13	1,287	2,180
Lease liability	3, 8	2,832	-
Decommissioning liability	9	32,782	26,334
Deferred income taxes		7,887	4,433
		183,221	157,603
Shareholders' equity			
Share capital	10	391,444	391,444
Contributed surplus	11	16,949	15,141
Retained earnings		9,753	1,346
		418,146	407,931
Commitments	15		
		$ 601,367	$ 565,534

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)	Notes	Three Months Ended Sept. 30 2019	Three Months Ended Sept. 30 2018	Nine Months Ended Sept. 30 2019	Nine Months Ended Sept. 30 2018
Revenue					
Revenue from product sales	7	$ 31,417	$ 51,253	$ 124,751	$ 151,459
Royalties		332	(1,934)	(4,902)	(6,938)
		31,749	49,319	119,849	144,521
Realized gain (loss) on risk management contracts	13	2,811	(3,253)	(7,189)	(4,816)
		34,560	46,066	112,660	139,705
Expenses					
Production		10,068	10,419	31,611	29,972
Transportation		9,981	11,257	30,995	32,277
General and administrative		1,359	1,240	5,438	4,984
Share-based compensation	11	648	823	1,808	2,289
Depletion and depreciation	5, 8	9,550	11,772	29,250	34,818
Exploration and evaluation costs expensed	4	-	-	1,119	277
Accretion	9	120	129	372	384
Interest and finance costs		1,215	923	3,648	3,321
Unrealized (gain) loss on risk management contracts	13	1,277	2,372	(3,540)	18,118
Unrealized revaluation (gain) loss on investment		81	(43)	98	12
		34,299	38,892	100,799	126,452
Net income and comprehensive income		261	7,174	11,861	13,253
Deferred income tax expense		325	-	3,454	-
Net income (loss) and comprehensive income (loss)		$ (64)	$ 7,174	$ 8,407	$ 13,253
Net income (loss) per share					
- Basic and diluted	12	$ (0.00)	$ 0.06	$ 0.07	$ 0.11

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)			Nine Months Ended September 30, 2019		
	Notes	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, beginning of period		$ 391,444	$ 15,141	$ 1,346	$ 407,931
Net income for the period		-	-	8,407	8,407
Share-based compensation	11	-	1,808	-	1,808
Balance, end of period		$ 391,444	$ 16,949	$ 9,753	$ 418,146

(Canadian $000s) (unaudited)			Nine Months Ended September 30, 2018		
	Notes	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period		$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the period		-	-	13,253	13,253
Share-based compensation	11	-	2,289	-	2,289
Balance, end of period		$ 391,444	$ 14,303	$ (25,464)	$ 380,283

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Notes	Three Months Ended Sept. 30 2019	Three Months Ended Sept. 30 2018	Nine Months Ended Sept. 30 2019	Nine Months Ended Sept. 30 2018
Operating activities					
Net income (loss) for the period		$ (64)	$ 7,174	$ 8,407	$ 13,253
Non-cash items:					
Unrealized (gain) loss on risk management	13	1,277	2,372	(3,540)	18,118
Depletion, depreciation and accretion	5, 8, 9	9,670	11,901	29,622	35,202
Share-based compensation	11	648	823	1,808	2,289
Lease interest	8	36	-	112	-
Exploration and evaluation costs expensed	4	-	-	1,119	277
Unrealized revaluation (gain) loss on investment		81	(43)	98	12
Deferred income tax expense		325	-	3,454	-
Funds flow		11,973	22,227	41,080	69,151
Net change in non-cash working capital items	14	(1,202)	(773)	11,702	(1,272)
		10,771	21,454	52,782	67,879
Financing activities					
Payment on lease liability	8	(125)	-	(374)	-
Increase (decrease) in bank indebtedness		22,892	(8,562)	20,688	(22,248)
		22,767	(8,562)	20,314	(22,248)
Investing activities					
Additions to property and equipment	5	(33,660)	(19,967)	(72,214)	(44,672)
Additions to exploration and evaluation assets	4	(264)	(1,878)	(1,799)	(2,991)
Disposition of exploration and evaluation assets	4	1,083	-	1,083	-
Net change in non-cash working capital items	14	(697)	8,953	(166)	2,032
		(33,538)	(12,892)	(73,096)	(45,631)
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 September 30, 2019 and December 31, 2018 and for the three and nine months ended September 30, 2019 and 2018

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

1. REPORTING ENTITY

Storm Resources Ltd. (the "Company" or "Storm"), is a crude oil and natural gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX under the symbol "SRX". The Company operates primarily in the province of British Columbia and its head office is located at Suite 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4. 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

The financial statements have been prepared 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"). Certain information and disclosures normally included in the notes to the consolidated financial statements have been condensed or have been disclosed on an annual basis only. Accordingly, these condensed interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements as at and for the year ended December 31, 2018. 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 November 12, 2019.

Basis of Measurement

The Company's financial statements have been prepared on a going concern basis consistent with prior years, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 13.

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, 2018.

3. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 *Leases* which is effective January 1, 2019 and replaces IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which requires lessees to recognize assets and liabilities for essentially all leases previously classified as operating leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases.

Effective January 1, 2019, the Company adopted IFRS 16 *Leases* using the modified retrospective approach, whereby the cumulative effect of initially applying the standard resulted in the initial recognition of a $3.1 million "Right-of-use asset" with a corresponding increase to "Lease liability" primarily relating to the Company's corporate office lease in Calgary. The modified retrospective approach does not require restatement of prior period comparative financial information and is applied prospectively.

The lease liability was measured at the present value of the remaining lease payments, discounted using the Company's weighted average incremental borrowing rate of approximately 5% on January 1, 2019. The right-of-use asset was measured at amounts equal to the corresponding initial lease liability.

On adoption, the Company used the following practical expedients permitted by the standard:

- Accounted for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases; and
- Accounted for lease payments as an expense for leases for low-value assets.

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company's lease liability as at January 1, 2019:

		Total
Transportation and processing commitments	$	384,707
Office lease		5,773
Commitments as at December 31, 2018		390,480
Less:		
Agreements that do not contain a lease		(384,707)
Non-lease components		(2,082)
Lease liability commitments as at December 31, 2018		3,691
Discounting at incremental borrowing rate of 5%		(597)
Lease liability as at January 1, 2019	$	3,094

Update to Significant Accounting Policies

Lease Liabilities and Right-of-Use Assets

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease liability is recognized at the present value of future lease payments, using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. A corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs. The Company has elected not to recognize leases for short-term leases with a lease term of twelve months or less, or leases for low-value assets. Payments are applied against the lease liability and interest expense is recognized on the lease liability using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

4. EXPLORATION AND EVALUATION

	Nine Months Ended September 30, 2019	Year ended December 31, 2018
Balance, beginning of period	$ 102,277	$ 103,907
Additions	1,799	4,034
Dispositions	(1,083)	
Expiries - exploration and evaluation costs expensed	(1,119)	(277)
Future decommissioning costs	76	370
Transfer to property and equipment	-	(5,757)
Balance, end of period	$ 101,950	$ 102,277

As at September 30, 2019, management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment and concluded that there are no indicators of impairment.

5. PROPERTY AND EQUIPMENT

	Nine Months Ended September 30, 2019	Year ended December 31, 2018
Cost		
Balance, beginning of period	$ 646,983	$ 559,524
Additions	72,214	80,729
Future decommissioning costs	6,000	973
Transfer from exploration and evaluation assets	-	5,757
Balance, end of period	$ 725,197	$ 646,983
Accumulated depletion and depreciation		
Balance, beginning of period	$ (216,182)	$ (170,565)
Depletion and depreciation	(28,923)	(45,617)
Balance, end of period	$ (245,105)	$ (216,182)
Net book value, beginning of period	$ 430,801	$ 388,959
Net book value, end of period	$ 480,092	$ 430,801

As at September 30, 2019, the Company determined that there were no indicators of impairment to property and equipment.

As at September 30, 2019, the balance of assets under construction not subject to depreciation or depletion was $49.0 million (December 31, 2018 - $11.4 million) and relates to the construction of a sour gas plant at Nig, located in northeast British Columbia.

6. BANK INDEBTEDNESS

As at September 30, 2019, the Company had an extendible revolving credit facility in the amount of $205 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 29, 2020, 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 in full one year later. In the event that the lenders reduce the borrowing base below the amount drawn, the Company would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. Interest is paid on the utilized portion of the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral provided comprises a floating charge demand debenture on the assets of the Company.

As at September 30, 2019, the Company had issued letters of credit in the amount of $10.0 million (December 31, 2018 - $7.6 million) in support of future natural gas transportation and processing obligations. Available capacity under the Company's credit facility is reduced by a like amount.

7. REVENUE FROM PRODUCT SALES

The following table presents the Company's revenue from product sales disaggregated by revenue source:

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Natural gas	$ 20,252	$ 30,136	$ 82,652	$ 90,879
Condensate	10,836	16,098	36,726	45,815
NGL	329	5,019	5,373	14,765
Total	$ 31,417	$ 51,253	$ 124,751	$ 151,459

Storm's revenue was generated mostly in British Columbia where production was sold primarily to two major energy customers with investment grade credit ratings which accounted for 83% and 81% of the Company's total revenue from product sales for the three and nine months ended September 30, 2019, respectively (September 30, 2018 – 46% and 49%, respectively, from one major customer). The majority of revenues are derived from variable price contracts based on index prices at each sales point. Of total natural gas revenue for the nine months ended September 30, 2019, 58% received Chicago pricing, 18% received Station 2 pricing, 11% received Sumas pricing, 11% received AECO pricing and the remaining 2% received ATP pricing.

8. RIGHT-OF-USE ASSET AND LEASE LIABILITY

Right-of-Use Asset

The following table provides a reconciliation of the carrying amount of the right-of-use asset on initial adoption of the lease standard on January 1, 2019 pertaining to the Company's corporate office lease in Calgary:

	Nine Months Ended September 30, 2019
Cost	
Balance, beginning of period (Note 3)	$ 3,094
Additions	-
Balance, end of period	$ 3,094
Accumulated depreciation	
Balance, beginning of period	$ -
Depreciation	(327)
Balance, end of period	$ (327)
Net book value, beginning of period	$ 3,094
Net book value, end of period	$ 2,767

As at September 30, 2019, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is $2.8 million with a remaining lease term to the year 2026.

Lease Liability

The following table provides a reconciliation of the carrying amount of the liability recognized on initial adoption of the lease standard on January 1, 2019 pertaining to the Company's corporate office lease in Calgary:

	Nine Months Ended September 30, 2019
Balance, beginning of period (Note 3)	$ 3,094
Lease payments	(374)
Lease interest	112
Balance, end of period	$ 2,832

As at September 30, 2019, the total undiscounted amount of the estimated future cash flows to settle the Company's lease liability over the remaining lease term is $3.3 million.

Short-term leases are leases with a lease term of twelve months or less. During the nine months ended September 30, 2019, short-term lease costs of approximately $1.7 million were incurred primarily relating to the lease of drilling equipment which was captured within property and equipment costs.

9. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning crude oil and natural 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 and inflated liability required to settle the Company's decommissioning obligation is approximately $46.5 million (December 31, 2018 - $43.2 million), with the majority of payments being made in the years 2034 to 2053. A risk-free discount rate of 1.6% (December 31, 2018 – 2.2%) and an inflation rate of 2.0% (December 31, 2018 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $32.8 million at September 30, 2019. Currently there are no material decommissioning costs expected to be incurred within the next year.

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

	Nine Months Ended September 30, 2019	Year Ended December 31, 2018
Balance, beginning of period	$ 26,334	$ 24,474
Obligations incurred	2,221	1,406
Obligations settled	(49)	(242)
Change in estimates(1)	3,904	179
Accretion expense	372	517
Balance, end of period	$ 32,782	$ 26,334

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

10. SHARE CAPITAL

Authorized

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

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2018 and September 30, 2019	121,557	$ 391,444

For the period from January 1, 2019 to November 12, 2019 there were no common shares issued upon the exercise of stock options.

11. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the volume weighted average price of the shares on the TSX for the five trading days immediately preceding the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at September 30, 2019, a total of 12,155,681 common shares were available for issuance. At September 30, 2019, and at November 12, 2019, the date of this report, options in respect of 9,102,400 common shares were issued and outstanding and options in respect of 3,053,281 common shares were available for future issue.

Details of the options outstanding at September 30, 2019 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2018	9,088	$ 3.29
Granted during the period	238	$ 1.99
Cancelled/forfeited during the period	(184)	$ 3.34
Expired during the period	(40)	$ 4.71
Outstanding at September 30, 2019	9,102	$ 3.24
Number exercisable at September 30, 2019	4,028	$ 3.97

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$1.65 - $2.86	5,022	2.8	$ 2.30	774	$ 2.86
$2.87 - $4.50	2,066	0.5	$ 3.44	1,911	$ 3.42
$4.51 - $5.50	2,014	1.2	$ 5.39	1,343	$ 5.39
Total	9,102	1.9	$ 3.24	4,028	$ 3.97

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

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the nine months ended September 30, 2019 of $0.72 per share include the following:

	2019
Share price	$1.99
Exercise price	$1.99
Volatility	47%
Forfeiture rate	2%
Expected option life (years)	3.7
Risk-free interest rate	1.5%

Share-based compensation expense of $0.6 million and $1.8 million was charged to the consolidated statement of income (loss) during the three and nine months to September 30, 2019, respectively (2018 - $0.8 million and $2.3 million, respectively) with an equivalent offset to contributed surplus.

12. NET INCOME (LOSS) PER SHARE

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

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Net income (loss) for the period	$ (64)	$ 7,174	$ 8,407	$ 13,253
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	121,557	121,557	121,557	121,557
Effect of shares issued	-	-	-	-
Weighted average number of common shares outstanding – basic	121,557	121,557	121,557	121,557
Dilutive effect of outstanding options(1)	-	-	-	-
Weighted average number of common shares outstanding - diluted	121,557	121,557	121,557	121,557
Net income (loss) per share				
Basic and diluted	$ (0.00)	$ 0.06	$ 0.07	$ 0.11

(1) Excludes effect of 9.1 million weighted average common shares related to stock options that were anti-dilutive for the three and nine months ended September 30, 2019 (8.4 million and 8.8 million weighted average common shares related to stock options for each of the three and nine months ended September 30, 2018, respectively).

13. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness and risk management 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 and interest rates, 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 risk management contracts described below is based on forward prices of commodities and interest rates 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 nine months ended September 30, 2019.

The Company's risk management 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 September 30, 2019:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Risk management contracts			
Current asset	$ 22,254	$ (20,787)	$ 1,467
Long-term asset	40	(40)	-
Current liability	(20,787)	20,787	-
Long-term liability	(1,327)	40	(1,287)
Net position	$ 180	$ -	$ 180

The following is a summary of the Company's financial assets and financial liabilities that were subject to offset as at December 31, 2018:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Risk management contracts			
Current asset	$ 6,900	$ (4,559)	$ 2,341
Long-term asset	-	-	-
Current liability	(8,080)	4,559	(3,521)
Long-term liability	(2,180)	-	(2,180)
Net position	$ (3,360)	$ -	$ (3,360)

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 crude 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 September 30, 2019, the Company's two major energy customers with investment grade credit ratings accounted for $9.3 million of total receivables (December 31, 2018 - $22.1 million from one major customer) and 83% and 81% of total revenues for the three and nine months ended September 30, 2019, respectively (three and nine months ended September 30, 2018 – 46% and 49%, respectively). 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 September 30, 2019, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at September 30, 2019.

The maximum exposure to credit risk at September 30, 2019 was the carrying amount of accounts receivable of $14.5 million and risk management contract assets of $1.5 million. No receivables were impaired at September 30, 2019.

Risk Management

At the date of this report, Storm has the undernoted risk management contracts in place. The fair market value of these contracts at September 30, 2019, a net asset position of $0.2 million (December 31, 2018 – net liability position of $3.4 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the three and nine months ended September 30, 2019, this resulted in an unrealized mark-to-market loss of $1.3 million and an unrealized mark-to-market gain of $3.5 million, respectively (2018 – unrealized losses of $2.4 million and $18.1 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		
Oct – Dec 2019	38,000 Mmbtu	Chicago Cdn$3.24/Mmbtu
Oct – Dec 2019	8,500 Mmbtu	Sumas Cdn$2.67/Mmbtu
Nov 2019 – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Nov 2019 – Mar 2020	9,000 GJ	Station 2 Cdn$1.94/GJ
Dec 2019 – Mar 2020	4,000 GJ	Station 2 Cdn$1.88/GJ
Jan – Mar 2020	7,000 Mmbtu	Sumas Cdn$3.93/Mmbtu
Jan – Jun 2020	20,000 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jul – Dec 2020	1,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Natural Gas Collars		
Nov 2019 – Mar 2020	5,500 GJ	AECO $1.77 - $2.28 Cdn$/GJ
Natural Gas Differential Swaps		
Jan – Dec 2020	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.274/Mmbtu
Jan – Dec 2021	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.256/Mmbtu
Crude Oil Collars		
Oct – Dec 2019	850 Bbls	$73.28 - $87.95 Cdn$/Bbl
Jan – Jun 2020	750 Bbls	$71.07 - $81.21 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2019	650 Bbls	$81.51 Cdn$/Bbl
Jan – Jun 2020	750 Bbls	$71.92 Cdn$/Bbl
Condensate Differential Swaps		
Oct – Dec 2019	600 Bbls	WTI minus Cdn$6.13/Bbl
Jan – Dec 2020	600 Bbls	WTI minus Cdn$7.90/Bbl
Propane Swaps		
Oct – Dec 2019	200 Bbls	$42.87 Cdn$/Bbl

In the second quarter of 2019, the Company entered into an interest rate swap contract to manage the uncertainty of variable interest rates by fixing the variable component of a portion of the interest paid on the Company's revolving bank facility. Interest rate swaps are classified as derivative financial assets and liabilities at fair value through profit and loss and measured at fair value, with gains and losses on re-measurement included as a component of unrealized risk management contracts in the period in which they arise. This interest rate swap is included on the balance sheet as either a risk management contract asset or liability and is classified as current or non-current based on the contractual terms specific to the instrument. As at September 30, 2019, the Company had the following interest rate contract in place to manage interest rate risk:

Index	Effective Date	Notional Principal	Remaining Term	Fixed Contract Rate
One-month bankers' acceptance – CDOR(1)	May 31, 2019	$25 million	Oct 2019 – May 2022	1.949%

(1) Canadian Dollar Offered Rate.

The Company realized a gain from risk management contracts in place in the amount of $2.8 million for the three months ended September 30, 2019 and realized a loss of $7.2 million for the nine months ended September 30, 2019 (2018 – realized losses of $3.3 million and $4.8 million, respectively).

Physical Delivery Sales Contract

The Company also enters into physical delivery sales contracts from time to time to manage commodity price risk. These contracts are considered normal executory contracts and are not recognized in the consolidated statement of income (loss) and comprehensive income (loss) until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Oct 2019 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income (loss) due to changes in the fair value of risk management contracts in place at September 30, 2019. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor	Nine Months Ended September 30, 2019
Increase of US$10.00/Bbl in the price of WTI[1]	$ (4,095)
Decrease of US$10.00/Bbl in the price of WTI[1]	$ 4,095
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (2,036)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 2,036

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

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to Sept. 30, 2019	Three Months to Sept. 30, 2018	Nine Months to Sept. 30, 2019	Nine Months to Sept. 30, 2018
Accounts receivable	$ (3,613)	$ (3,567)	$ 14,650	$ (8)
Prepaids and deposits	(190)	(157)	276	3,697
Accounts payable and accrued liabilities	1,904	11,904	(3,390)	(2,929)
Change in non-cash working capital	$ (1,899)	$ 8,180	$ 11,536	$ 760
Relating to:				
Operating activities	$ (1,202)	$ (773)	$ 11,702	$ (1,272)
Investing activities	(697)	8,953	(166)	2,032
Change in non-cash working capital	$ (1,899)	$ 8,180	$ 11,536	$ 760
Interest paid during the period	$ 1,218	$ 886	$ 3,523	$ 3,237
Income taxes paid during the period	$ -	$ -	$ -	$ -

15. COMMITMENTS

At September 30, 2019, the Company has the following long-term commitments over the next five years and thereafter:

	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing commitments	$ 14,573	$ 59,390	$ 61,781	$ 47,844	$ 25,077	$ 210,578	$ 419,243
Office lease[1]	91	356	356	356	356	741	2,256
Total	$ 14,664	$ 59,746	$ 62,137	$ 48,200	$ 25,433	$ 211,319	$ 421,499

(1) Office lease commitment includes the operating cost component of the office lease costs.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & Chief Executive Officer

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
President & Chief Executive Officer

Sheila A. Leggett (2)

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

---

Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol "SRX"

Solicitors

Stikeman Elliott 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
Canadian Western Bank
Calgary, Alberta

Executive Offices

Suite 600, 215 – 2nd Street S.W.
Calgary, Alberta, T2P 1M4 Canada
Tel: (403) 817-6145 Fax: (403) 817-6146
www.stormresourcesltd.com

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
kPa	Kilopascal
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
PDP	Proved developed producing reserves
1P	Proved reserves
2P	Proved plus probable reserves
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

Storm Resources Ltd.
Suite 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4
Phone: (403) 817-6145   Fax: (403) 817-6146

www.stormresourcesltd.com