

Highlights

Thousands of Cdn\$, except volumetric and per-share amounts	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
FINANCIAL				
Revenue from product sales ⁽¹⁾	30,191	37,568	72,114	93,334
Funds flow	10,904	12,590	27,793	29,107
Per share – basic and diluted (\$)	0.09	0.10	0.23	0.24
Net income (loss)	(11,665)	7,864	(1,153)	8,471
Per share – basic and diluted (\$)	(0.10)	0.06	(0.01)	0.07
Cash return on capital employed ("CROCE") ⁽²⁾	12%	18%	12%	18%
Return on capital employed ("ROCE") ⁽²⁾	2%	11%	2%	11%
Capital expenditures	2,394	23,145	28,869	40,089
Debt including working capital deficiency ⁽²⁾⁽³⁾	130,317	102,268	130,317	102,268
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⁾	13.86	20.72	16.55	25.95
Transportation costs	(5.50)	(5.96)	(5.24)	(5.84)
Revenue net of transportation	8.36	14.76	11.31	20.11
Royalties	(0.44)	(0.32)	(0.70)	(1.46)
Production costs	(4.50)	(5.89)	(4.83)	(5.99)
Field operating netback ⁽²⁾	3.42	8.55	5.78	12.66
Realized gain (loss) on risk management contracts	2.99	(0.22)	2.12	(2.78)
General and administrative	(0.72)	(0.68)	(0.79)	(1.13)
Interest and finance costs	(0.68)	(0.71)	(0.71)	(0.66)
Decommissioning expenditures	(0.01)	-	(0.03)	-
Funds flow per Boe	5.00	6.94	6.37	8.09
Barrels of oil equivalent per day (6:1)	23,935	19,923	23,941	19,873
Natural gas production				
Thousand cubic feet per day	114,772	97,510	115,365	97,026
Price (Cdn\$ per Mcf) ⁽¹⁾	2.23	2.64	2.39	3.55
Condensate production				
Barrels per day	2,305	2,081	2,464	2,140
Price (Cdn\$ per barrel) ⁽¹⁾	25.92	71.12	44.41	66.85
NGL production				
Barrels per day	2,501	1,591	2,249	1,563
Price (Cdn\$ per barrel) ⁽¹⁾	6.23	4.87	4.92	17.83
Wells drilled (net)	-	-	1.0	5.0
Wells completed (net)	-	-	3.5	-
Wells started production (net)	1.0	1.0	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 25 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, decommissioning liability and lease liability.

PRESIDENT'S MESSAGE

2020 SECOND QUARTER HIGHLIGHTS

The considerable efforts made by Storm's employees mitigated the many impacts of the COVID-19 pandemic on the business. Compared to last year, production grew by 20% and there was a large realized hedging gain, however, this was offset by lower natural gas and condensate prices which reduced revenue. Production costs showed a significant improvement as a result of the start-up of the Nig Creek Gas Plant in February 2020. With capital expenditures minimized in the quarter, debt was reduced by \$8.3 million from the previous quarter.

- Production was 23,935 Boe per day, effectively unchanged from the previous quarter and an increase of 20% year over year. This was consistent with guidance for production to average 23,000 to 25,000 Boe per day. Year to date, three wells (3.0 net) have started production, all at West Umbach.
- Liquids production (condensate plus NGL) totaled 4,806 barrels per day, an increase of 4% from the previous quarter and an increase of 31% year over year. Liquids as a proportion of total production has increased as a result of higher NGL recoveries at the Nig Creek Gas Plant which started up in February 2020.
- The benefits of the Nig Creek Gas Plant were realized with corporate production costs declining by 31%, or \$1.39 per Boe, from last year while higher liquids recovery added approximately 500 barrels per day. The Nig Creek area represented 36% of corporate production while providing 60% of field operating income before hedging.
- Production from the Nig Creek wells continues to meet or exceed expectations with declines from the upper/mid Montney being shallower than expected while the first well in the lower Montney has a higher field condensate rate. The four most recent wells started production in November 2019 with rates over the first eight months averaging approximately 1,550 Boe per day sales (100 barrels per day field condensate) for the three wells in the upper/mid and approximately 875 Boe per day sales (170 barrels per day field condensate) for the lower.
- Revenue was \$13.86 per Boe, a 33% decline from last year mainly due to lower condensate and natural gas prices. The condensate price declined 64% as a result of the collapse in the WTI price (partially offset by a hedging gain). The natural gas price declined 16% as a result of declines in the Chicago and Sumas prices (66% of sales) which more than offset an increase in the AECO and BC Station 2 prices (29% of sales).
- Liquids increased to 20% of sales volumes (from 18% last year); however, the proportion of production revenue from liquids decreased to 23% from 38% last year as a result of the decline in the condensate price.
- Production, general and administrative, and interest and finance costs were \$5.90 per Boe, a year-over-year decrease of \$1.38 per Boe as a result of lower production costs resulting from the start-up of the Nig Creek Gas Plant in February.
- Hedging provided a realized gain of \$6.5 million versus a realized loss of \$0.4 million in the prior year. The majority of the gain, \$4.9 million, was from WTI crude oil contracts.
- Funds flow was \$10.9 million, or \$0.09 per share, a decrease of \$1.7 million from last year as a result of lower revenue per Boe which more than offset production growth, lower production costs per Boe and the hedging gain.
- Net loss was \$11.7 million with the largest contributor to the decrease from net income of \$7.9 million last year being an unrealized hedging loss (non-cash) of \$13.8 million which represents the change in the value of future hedging contracts.
- Capital investment was \$2.4 million (within guidance for less than \$3 million) and included \$1.5 million to complete the Nig Creek Gas Plant project.
- Total debt including working capital deficiency was \$130 million which is 3.0 times annualized quarterly funds flow. As part of the annual review, the bank line was voluntarily reduced to \$190 million (from \$205 million) in order to reduce the associated fees.
- The undiscounted and inflated decommissioning liability totaled \$35.4 million. The liability for currently inactive wells and facilities is approximately \$10 million with approximately 75% of this expected to be incurred by 2025.

OPERATIONS REVIEW

Umbach, Nig Creek and Fireweed Areas, Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and totals 121,000 net acres (172 net sections) with 79 horizontal wells (74.4 net) drilled to the end of the second quarter.

Field activity in the second quarter was minimal while activity in the second half of the year will include drilling four (4.0 net) horizontal wells at the Nig Creek area in the third quarter which are planned for completion and tie-in early in the fourth quarter. In addition, there are three contingent horizontal wells (3.0 net) planned for the Umbach area in the fourth quarter depending on commodity prices and forecasted funds flow.

At the end of the quarter, there were four (2.5 net) drilled Montney horizontal wells that had not started producing which included two (1.0 net) completed wells, both at Fireweed.

At Umbach (average 90% working interest), produced raw natural gas contains 1.2% H₂S with approximately 80% directed to the McMahon Gas Plant and 20% to the Stoddart Gas Plant. Firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon and 15 Mmcf per day at Stoddart). There remains significant capacity for future growth given second quarter volumes averaged 83 Mmcf per day raw which is significantly less than field compression capacity at 150 Mmcf per day raw gas.

At Nig Creek (100% working interest), produced raw natural gas contains 0.1% H₂S and is directed to the 50 Mmcf per day sour gas plant that started up in February 2020. During the second quarter, inlet volumes averaged 43 Mmcf per day raw, sales were 8,510 Boe per day with liquids at 48 barrels per Mmcf sales, the operating cost for the area was \$1.03 per Boe, and the operating netback was \$5.77 per Boe (\$2.34 per Boe higher than the corporate average). With the decline in the WTI crude oil price in the first half of 2020, the plant has been 'warmed up' since mid-April which has reduced NGL recovery by approximately 8 barrels per Mmcf sales (propane and butane). The plant is expected to reach fully capacity in the fourth quarter after the next four wells are drilled and completed (from an existing pad which is already pipeline connected).

At Fireweed (50% working interest), there was no activity in the quarter as development was deferred on May 12, 2020 by up to one year in response to the collapse in the WTI crude oil price. With the recent improvement in the WTI crude oil price, activity is likely to resume in the first quarter of 2021 with first production in the second half of 2021. There are currently three standing wells (1.5 net) with two wells (1.0 net) having been completed. 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 Creek and Umbach is provided below. IP90 and IP180 rates are less reliable indicators of relative longer-term performance since wells are initially rate restricted to manage fluid rates.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2017 - 2018 19 hz's	34	1895 m	4.6 Mmcf/d ⁽¹⁾ 24 Bbls/Mmcf ⁽²⁾ 19 hz's	4.4 Mmcf/d ⁽¹⁾ 20 Bbls/Mmcf ⁽²⁾ 19 hz's	4.0 Mmcf/d ⁽¹⁾ 15 Bbls/Mmcf ⁽²⁾ 19 hz's
Nig Creek 2018 upper 3 hz's	37	2180 m	8.1 Mmcf/d ⁽¹⁾ 29 Bbls/Mmcf ⁽²⁾ 3 hz's	8.2 Mmcf/d ⁽¹⁾ 25 Bbls/Mmcf ⁽²⁾ 3 hz's	7.5 Mmcf/d ⁽¹⁾ 21 Bbls/Mmcf ⁽²⁾ 3 hz's
Nig Creek 2019 upper/mid 3 hz's	42	2240 m	8.1 Mmcf/d ⁽¹⁾ 20 Bbls/Mmcf ⁽²⁾ 3 hz's	7.9 Mmcf/d ⁽¹⁾ 15 Bbls/Mmcf ⁽²⁾ 3 hz's	

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Nig Creek 2019 lower 1 hz	42	2280 m	5.5 Mmc/d ⁽¹⁾ 57 Bbls/Mmc ⁽²⁾ 1 hz	4.1 Mmc/d ⁽¹⁾ 49 Bbls/Mmc ⁽²⁾ 1 hz	
Umbach 2020 3 hz's	38	2420 m	4.4 Mmc/d ⁽¹⁾ 15 Bbls/Mmc ⁽²⁾ 3 hz's		

(1) Raw gas rate.

(2) Bbls/Mmc is the condensate-gas ratio or barrels of field condensate per Mmc 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 Creek 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

Commodity price hedges are used to support longer-term growth by protecting pricing on up to 50% of current production for the next 18 months and up to 25% for 19 to 36 months forward (future production growth is not hedged). The current hedge position is shown below (excludes price differential contracts which are shown in the financial statements) with hedges for the remainder of 2020 protecting approximately 47% of current production (based on production in the first half of 2020).

	H2/20	2021
Natural Gas Hedges		
% Current Nat Gas Production ⁽¹⁾	49%	48%
Collars	31,800 Mcf/d ⁽²⁾ Floor Cdn\$2.82 per Mcf ⁽³⁾ Ceiling Cdn\$3.06 per Mcf ⁽³⁾	8,400 Mcf/d ⁽²⁾ Floor Cdn\$3.83 per Mcf ⁽³⁾ Ceiling Cdn\$4.40 per Mcf ⁽³⁾
Fixed Price	24,500 Mcf/d ⁽²⁾ Cdn\$2.97 per Mcf ⁽³⁾	46,900 Mcf/d ⁽²⁾ Cdn\$2.89 per Mcf ⁽³⁾
Crude Oil Hedges		
% Current Liquids Production ⁽¹⁾	41%	28%
Collars	800 Bpd Floor WTI Cdn\$57.81 per barrel Ceiling WTI Cdn\$67.08 per barrel	650 Bpd Floor WTI Cdn\$50.54 per barrel Ceiling WTI Cdn\$59.93 per barrel
Fixed Price	950 Bpd WTI Cdn\$59.56 per barrel 200 Bpd Propane Conway Cdn\$28.25 per barrel	625 Bpd WTI Cdn\$52.64 per barrel 50 Bpd Propane Conway Cdn\$27.30 per barrel

(1) Using H1/20 actual production.

(2) Using corporate average heat content 1.23 GJ per Mcf and 1.17 Mmbtu per Mcf.

(3) Hedges in US\$ are converted using an exchange rate of Cdn\$1.34 per US\$1.

OUTLOOK

Production in the third quarter of 2020 is forecast to average 19,000 to 21,000 Boe per day which includes the effect of a 28-day planned maintenance turnaround at the McMahon Gas Plant in September plus a 6-day unplanned outage which occurred in July. Approximately 11,000 Boe per day will be affected by the planned and unplanned outages. The financial cost for the outages is estimated to be \$2 million which includes unused firm pipeline transportation, natural gas purchased to fulfill marketing commitments related to hedging and unused firm gas processing commitments.

Capital investment in the third quarter is expected to be \$10 to \$15 million which will include drilling four wells (4.0 net) from an existing pad at Nig Creek plus starting the completions in late September.

Updated guidance for 2020 is provided below. Forecast production includes the effect of the third quarter outages described above and reduced NGL recovery after 'warming up' the Nig Creek Gas Plant. The reduction in forecast annual production reflects the effect of outages in the third quarter being greater than previously anticipated. The increase in fourth quarter production comes from the completion and tie-in of four wells at Nig Creek. Capital investment is intended to be approximately equal to or less than forecast funds flow. Forecast pricing reflects actual prices to date plus the approximate forward strip for the remainder of the year.

2020 Guidance

	Previous May 12, 2020	Current August 13, 2020
Cdn\$/US\$ exchange rate	0.72	0.74
Chicago daily natural gas - US\$/Mmbtu	\$2.05	\$1.85
Sumas monthly natural gas - US\$/Mmbtu	\$2.20	\$2.00
AECO daily natural gas - Cdn\$/GJ	\$2.20	\$2.00
BC Station 2 daily natural gas - Cdn\$/GJ	\$2.15	\$1.95
WTI - US\$/Bbl	\$30.50	\$38.50
Edmonton condensate diff - US\$/Bbl	(\$4.50)	(\$3.50)
Est revenue net of transport (excl hedges) - \$/Boe	\$12.00 - \$13.00	\$12.00 - \$12.50
Est production costs - \$/Boe	\$4.50 - \$4.75	\$4.50 - \$4.75
Est royalty rate (% revenue net transportation)	5% - 6%	5% - 6%
Est mid-point field operating netback - \$/Boe ⁽¹⁾	\$7.20	\$6.70
Est realized hedging gains or (losses) - \$ million	\$11.0 - \$12.0	\$10.0 - \$11.0
Est cash G&A - \$ million	\$6.0 - \$7.0	\$6.0 - \$7.0
Est interest expense - \$ million	\$7.0 - \$8.0	\$7.0 - \$8.0
Est capital investment (excluding A&D) - \$ million	\$52.0 - \$60.0	\$52.0 - \$60.0
	(Nig Crk GP \$12.0 million)	(Nig Crk GP \$12.0 million)
Forecast fourth quarter Boe/d	25,000 - 28,000	25,000 - 28,000
Forecast fourth quarter liquids Bbls/d	5,100 - 5,600	5,100 - 5,600
Forecast annual Boe/d	23,500 - 26,000	22,500 - 24,000
Forecast annual liquids Bbls/d	4,500 - 5,000	4,300 - 4,800
Est annual funds flow - \$ million	\$59.0 - \$66.0 ⁽²⁾	\$53.0 - \$57.0 ⁽²⁾
Horizontal wells drilled - gross	6 - 9 (5.0 - 8.0 net)	6 - 9 (5.0 - 8.0 net)
Horizontal wells completed - gross	8 (7.5 net)	8 (7.5 net)
Horizontal wells starting production - gross	7 (7.0 net)	7 (7.0 net)

(1) Based on the mid-point for each of revenue net of transportation, royalty rate and production costs.

(2) 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)	BC Station 2 Daily (Cdn\$/GJ)	WTI (US\$/Bbl)	Capital Investment (\$ million)	Forecast Annual Funds Flow (\$ million)	Forecast Annual Production (Boe/d)
Nov 12, 2019	\$2.45	\$1.60	\$54.00	\$75.0 - \$90.0	not provided	24,000 - 26,000
Feb 27, 2020	\$1.90	\$1.65	\$50.50	\$75.0 - \$85.0	\$62.0 - \$69.0	23,500 - 26,000
May 12, 2020	\$2.05	\$2.15	\$30.50	\$52.0 - \$60.0	\$59.0 - \$66.0	23,500 - 26,000
Aug 13, 2020	\$1.85	\$1.95	\$38.50	\$52.0 - \$60.0	\$53.0 - \$57.0	22,500 - 24,000

Capital investment in 2020 will be allocated as follows:

- \$7 million at Fireweed to drill two horizontal wells (1.0 net), complete one well (0.5 net); and start construction of the associated road and facility site;
- \$33 million at Nig Creek includes \$12 million to complete the gas plant (100% working interest), drill four horizontal wells (4.0 net) and complete and pipeline connect four wells (4.0 net); and
- \$12 - \$20 million at Umbach to complete and pipeline connect three horizontal wells (3.0 net) plus drill three horizontal wells (3.0) which are contingent on commodity prices and forecast funds flow.

Firm pipeline capacity and marketing arrangements are expected to result in approximately 54% of forecast natural gas production in 2020 being sold into Chicago, 19% at AECO, 14% at BC Station 2, 9% at Sumas and 4% at Alliance ATP.

Liquids production in the second quarter was reduced as much as possible after the collapse in the WTI price triggered by the COVID-19 pandemic and the subsequent effect on condensate and NGL prices. This was mainly done by curtailing wells with higher condensate-gas ratios in April and May when prices were the lowest and by 'warming up' the Nig Creek Gas Plant to reduce NGL recovery. Condensate production is no longer being curtailed since the price has improved significantly since the low in May; however, further improvement in propane prices is required before NGL recovery is maximized at the Nig Creek Gas Plant.

The decline in Storm's natural gas price in the first half of 2020 is largely from having 66% of sales into US markets at Chicago and Sumas where average prices declined by approximately 30% from last year and has more than offset a large improvement in Western Canadian natural gas prices at AECO and BC Station 2. This is a reverse of the situation from mid-2017 to late 2019 where higher Chicago and Sumas prices more than offset weak Western Canadian prices. Future sales are expected to become more balanced between US and Western Canadian markets as incremental production growth is directed to BC Station 2, expiry of the sales commitment at Sumas occurs in October 2020, and Storm has the option every year to renew all or a lesser amount of the capacity to Chicago. Storm's natural gas marketing strategy will continue to be based on diversifying sales as much as possible to mitigate regional price differences caused by supply/demand imbalances that are difficult to predict in terms of timing and duration.

Results from the first lower Montney horizontal well at Nig Creek are encouraging in terms of adding a second layer for development where condensate represents a higher proportion of production. The economics are currently being evaluated and, with less natural gas and more condensate, the WTI price will have the greatest effect on the timing and pace of development.

The improvement in the WTI price since May supports restarting development at Fireweed which could add approximately \$30 million to capital investment mainly in 2021. This was the amount that would have been invested in 2020 before the decision was made to delay development up to one year after the collapse in the WTI price. A final decision on restarting development, along with details around timing for capital investment and first production, will be provided when third quarter results are released in mid-November.

Given the recent volatility in commodity prices and continuing uncertainty in the world with respect to the longer-term financial effects from COVID-19, the plan for the second half of 2020 is to remain cautious by ensuring capital

investment is less than or equal to funds flow. Although activity is being limited in 2020, forecast average production is still expected to grow by approximately 15% to 20% year over year.

The efforts of everyone at Storm in successfully managing the many operational and personal challenges caused by the ongoing COVID-19 pandemic have allowed for a seamless transition to a new business environment and are greatly appreciated.

Financial results are expected to improve significantly in the fourth quarter of 2020 and into 2021 based on higher forward strip prices which are expected to provide a 'tailwind' (instead of the 'headwind' since early 2019 resulting from declining commodity prices) and with the financial benefits being realized from the Nig Creek Gas Plant.

Respectfully,



Brian Lavergne,
President and Chief Executive Officer

August 12, 2020

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

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

Forward-Looking Statements - Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated August 12, 2020 for the three and six months ended June 30, 2020.

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three and six months ended June 30, 2020. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2020, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2019, and (iii) the press release issued by the Company on August 12, 2020, 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 30, 2020 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 August 12, 2020.

See discussion related to "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 23 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 six months ended June 30, 2020, 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, 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 six month periods ended June 30, 2019.

OPERATIONAL AND FINANCIAL RESULTS

Overview

From an operational standpoint, the second quarter of 2020 was largely uneventful with little in the way of capital spending. Rather, the focus remained on managing through the low commodity prices brought on by an extended period of elevated supply levels that was further exacerbated by demand destruction from the economic shut-downs associated with the COVID-19 pandemic. For Storm, the transition to operating in a COVID-19 environment has been relatively seamless with very limited effect on the Company's operations. Given the ongoing uncertainty, the Company prioritized strengthening the balance sheet in the period, reducing debt including working capital deficiency by \$8.3 million from the end of the immediately preceding quarter. Total debt, including working capital deficiency, at quarter end amounted to \$130.3 million, down from \$138.6 million at the end of the first quarter.

While demand for crude oil has improved somewhat leading to a modest recovery in WTI prices, the economic situation remains highly volatile with threats of a second wave of COVID-19 at the forefront. As previously stated, the extent to which the ongoing presence of COVID-19 may affect the Company remains uncertain; however, it is possible that COVID-19 may have further adverse effects on commodity prices, the Company's business, results of operations and financial condition, depending on the severity and duration of the pandemic. While Storm entered these challenging times in a position of strength, both from an operational and liquidity standpoint, management will continue to monitor this highly fluid situation to determine what, if any, additional measures might need to be taken.

Production in the second quarter of 23,935 Boe per day was within the previously announced guidance range of 23,000 to 25,000 Boe per day and was flat with the immediately preceding quarter. Production increased 20% over the same period in the prior year, although the prior year is not directly comparable given twelve days of third-party outages in the second quarter of 2019. Funds flow fell by 35% from the immediately preceding quarter, and by 13% from the same period in the prior year, primarily due to the collapse in WTI prices and to a lesser extent from lower natural gas prices. Capital expenditures in the second quarter were minimal and consistent with previously announced guidance.

During the second quarter of 2020, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 20% of total production and contributed 23% to revenue in the period compared to 36% of revenue in the immediately preceding quarter and 38% of revenue in the comparable quarter of 2019, highlighting the effect of the collapse in WTI prices as a result of the COVID-19 pandemic. The contribution to revenue from condensate and NGL came in higher than the previously communicated level of 15% due to the modest recovery in WTI benchmark pricing in the period. As the majority of Storm's condensate and NGL revenue streams is based on crude oil reference prices, participation in the crude oil market has been an important contributor to Storm's revenue, with the significant drop in WTI prices driving materially lower realized condensate and NGL pricing for the second quarter of 2020, partially offset by increased hedging gains on crude oil contracts.

The natural gas price realized by the Company in the second quarter fell by 12% when compared to the first quarter of 2020, and was down 16% when compared to the same quarter of 2019. The decrease versus both the prior quarter and the second quarter of 2019 was the result of 66% of natural gas sales into US markets where benchmark pricing declined due to robust supply, high storage levels following lower demand from moderate winter weather, and a collapse in the global LNG market which reduced US LNG exports.

Capital expenditures for the second quarter of 2020 totaled \$2.4 million, the majority of which (approximately \$1.5 million) related to final costs associated with the Nig Creek Gas Plant. During the second quarter, one well was brought on stream. At quarter end the Company had an inventory of four (2.5 net) standing horizontal wells, which included two (1.0 net) completed wells. Based on the current capital program, a four-well pad (4.0 net) at Nig Creek will be drilled and completed in the second half of the year. In addition, a three-well pad (3.0 net) at Umbach will also be drilled subject to favourable commodity prices and funds flow. Based on this level of activity, fourth quarter production is forecast to be 25,000 to 28,000 Boe per day. It is anticipated that for the remainder of the year planned capital expenditures will be approximately equal to funds flow.

During the quarter, the Company's credit facility was confirmed at \$205 million, a testament to the quality of both Storm's reserve book and asset base. In an effort to reduce associated fees the Company voluntarily reduced its credit facility to \$190 million. The credit facility was approximately 75% drawn at the end of the second quarter (including \$13.3 million for outstanding letters of credit). With funds flow for the remainder of the year expected to be equal to capital expenditures, low maintenance capital, a strong hedge portfolio, and approximately \$47 million of unused credit capacity, Storm maintains adequate financial liquidity to manage through the current downturn in commodity prices.

Production and Revenue

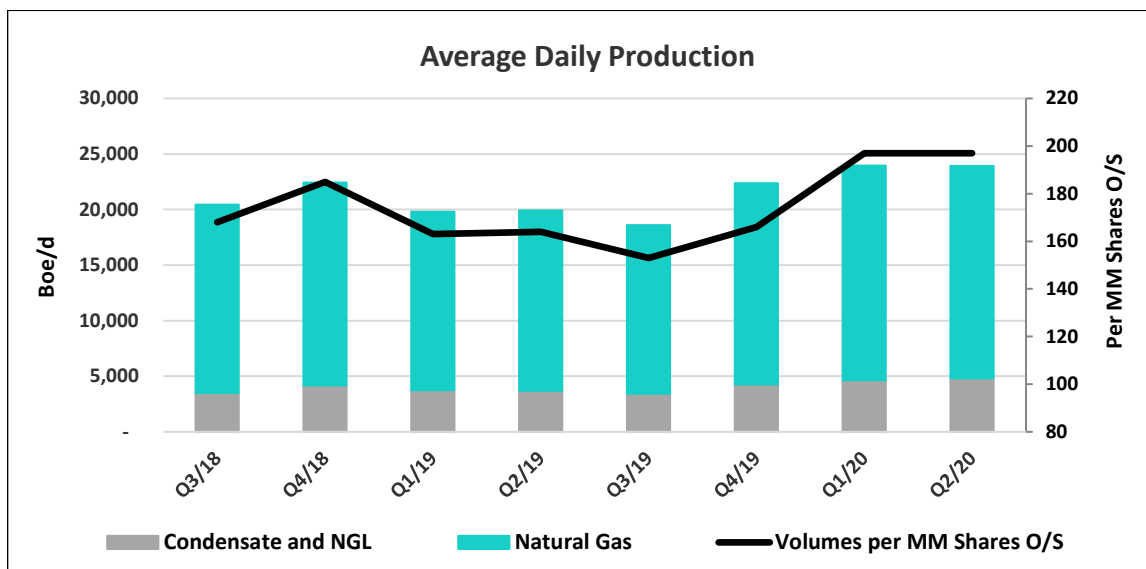
Average Daily Production

	Three Months to June 30, 2020	Three Months to June 30, 2019	Quarter-Over-Quarter Change	Six Months to June 30, 2020	Six Months to June 30, 2019	Year-Over-Year Change
Natural gas (Mcf/d)	114,772	97,510	18%	115,365	97,026	19%
Condensate (Bbls/d)	2,305	2,081	11%	2,464	2,140	15%
NGL (Bbls/d)	2,501	1,591	57%	2,249	1,563	44%
Total (Boe/d)	23,935	19,923	20%	23,941	19,873	20%
Natural gas weighting	80%	82%		80%	81%	
Condensate weighting	10%	10%		10%	11%	
NGL weighting	10%	8%		10%	8%	

Production for natural gas, condensate and NGL in the second quarter and first half of 2020 was 20% higher than the second quarter and first half of 2019 primarily due to 2019 being negatively affected by third-party outages, which totaled 12 days and 29 days, respectively.

In addition, the Nig Creek Gas Plant was commissioned in February 2020 leading to incremental production as a result of higher NGL recovery and reduced gas shrinkage.

The Company started production from one new 100% working interest horizontal well at Umbach in the second quarter of 2020 and three new 100% working interest horizontal wells at Umbach during the first six months of 2020.



Daily production per million shares outstanding at the end of the second quarter of 2020 averaged 197 Boe per day compared to 164 Boe per day for the second quarter of 2019, an increase of 20%.

Revenue from Product Sales⁽¹⁾

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Natural gas	\$ 23,335	\$ 23,396	\$ 50,185	\$ 62,400
Condensate	5,437	13,468	19,915	25,890
NGL	1,419	704	2,014	5,044
Total	\$ 30,191	\$ 37,568	\$ 72,114	\$ 93,334
% of Total Revenue by Product Type				
Natural gas	77%	62%	70%	67%
Condensate and NGL	23%	38%	30%	33%
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 second quarter of 2020 decreased by 20% when compared to the second quarter of 2019 primarily as a result of the Company's average realized price decreasing by 33%, partially offset by production volumes increasing by 20%. For the six month periods, revenue from product sales decreased by 23% year over year due to the Company's average realized price decreasing by 36%, partially offset by production volumes increasing by 20%.

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2019	\$ 23,396	\$ 13,468	\$ 704	\$ 37,568
Effect of changes in production	4,141	1,451	404	5,996
Effect of changes in average product prices	(4,202)	(9,482)	311	(13,373)
Revenue from product sales – Q2 2020	\$ 23,335	\$ 5,437	\$ 1,419	\$ 30,191

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2019 YTD	\$ 62,400	\$ 25,890	\$ 5,044	\$ 93,334
Effect of changes in production	12,204	4,088	2,256	18,548
Effect of changes in average product prices	(24,419)	(10,063)	(5,286)	(39,768)
Revenue from product sales – Q2 2020 YTD	\$ 50,185	\$ 19,915	\$ 2,014	\$ 72,114

Average Selling Prices⁽¹⁾

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Natural gas – Mcf	\$ 2.23	\$ 2.64	\$ 2.39	\$ 3.55
Condensate – Bbl	\$ 25.92	\$ 71.12	\$ 44.41	\$ 66.85
NGL – Bbl	\$ 6.23	\$ 4.87	\$ 4.92	\$ 17.83
Per Boe	\$ 13.86	\$ 20.72	\$ 16.55	\$ 25.95

(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 June 30, 2020 decreased by 33% compared to the same period of 2019, with the decrease driven by lower condensate and natural gas pricing. The decrease in condensate pricing is primarily due to a significant reduction in WTI benchmark pricing while the decrease in realized natural gas pricing is primarily due to a reduction in benchmark prices at Chicago and Sumas partially offset by higher BC Station 2 and AECO monthly index pricing. The Company's NGL price for the second quarter of 2020 was 16% of WTI compared to guidance of 10% to 15% of WTI and 28% higher than the second quarter of 2019 due to higher pricing for the April 2020 to March 2021 contract year which offset lower WTI.

On a per-Boe basis, the Company's average realized price for the first six months of 2020 decreased by 36% when compared to the first six months of 2019, driven by lower pricing across all product streams. The decrease in realized natural gas pricing is primarily due to lower Chicago and Sumas benchmark pricing partially offset by higher BC Station 2 pricing. The decrease in realized condensate pricing is due primarily to lower WTI pricing and the decrease in the Company's NGL price is primarily due to lower WTI and propane pricing.

Benchmark Prices

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Natural gas				
Chicago monthly index (US\$/Mmbtu)	1.63	2.45	1.79	2.89
Chicago daily index (US\$/Mmbtu)	1.64	2.31	1.69	2.67
Sumas (US\$/Mmbtu)	1.50	2.10	1.95	4.45
AECO monthly index (Cdn\$/GJ)	1.81	1.11	1.92	1.48
AECO daily index (Cdn\$/GJ)	1.89	0.98	1.91	1.73
BC Station 2 (Cdn\$/GJ)	1.87	0.56	1.87	0.90
Crude Oil				
WTI (US\$/Bbl)	27.85	59.81	37.01	57.36
WTI (Cdn\$/Bbl)	38.59	80.01	50.53	76.48
Edmonton condensate (Cdn\$/Bbl)	30.92	74.73	46.23	70.96
Exchange rate (US\$/Cdn\$)	0.72	0.75	0.73	0.75

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.

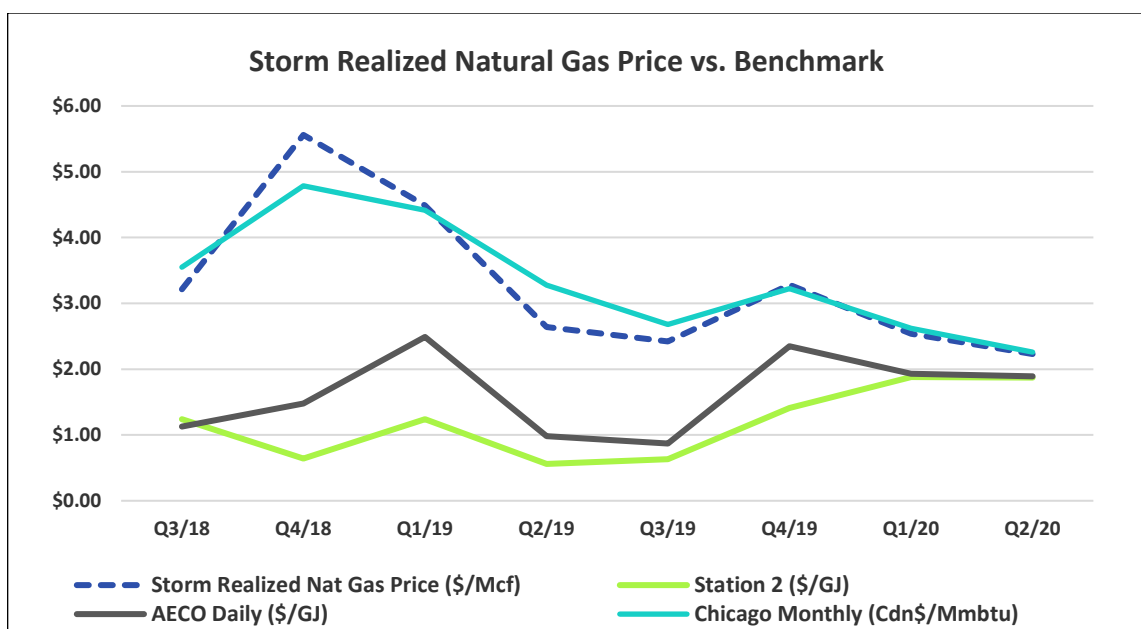
US natural gas prices trended lower in 2019, particularly in the latter half of the year, due to increasing supply and reduced demand through the summer and into shoulder season. US natural gas prices have been under further pressure in 2020 with higher storage levels due to moderate winter weather reducing demand through the fourth quarter of 2019 and into 2020.

BC Station 2 pricing increased in the second quarter of 2020 compared to the second quarter of 2019 due to a decline in receipts onto the Enbridge T-north system following completion of the TC Energy North Montney pipeline in January 2020.

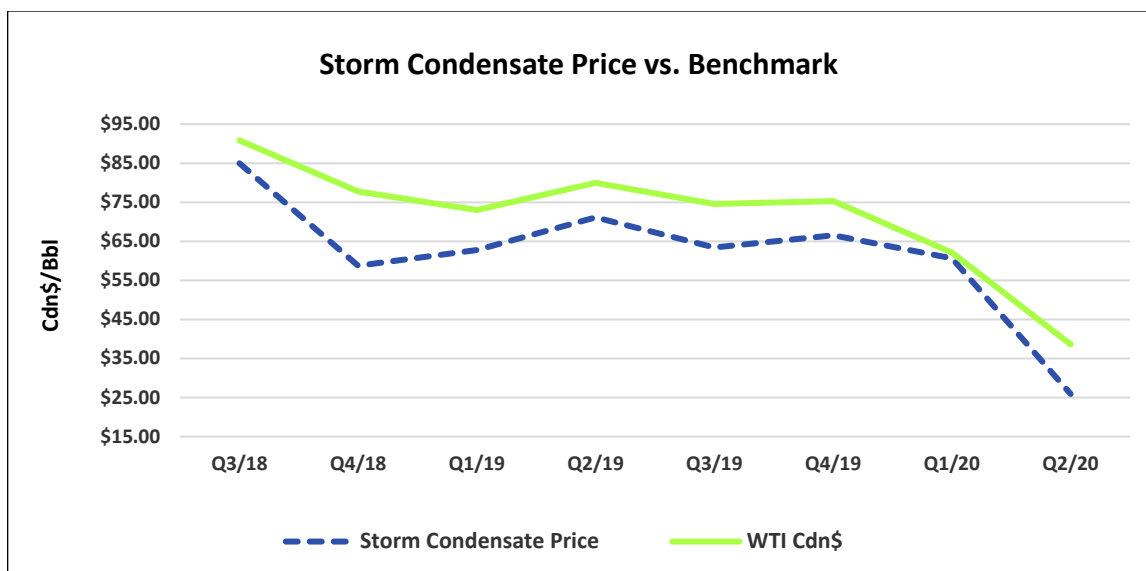
WTI crude oil pricing, the benchmark for mid-continent inland North American crude oil prices at Cushing, Oklahoma, on which a large part of the Company's condensate and NGL revenue is based, declined 53% from US\$59.81 per barrel during the second quarter of 2019, to US\$27.85 per barrel in the second quarter of 2020. The decline was the result of elevated supply levels, the onset of demand destruction from economic shut-downs associated with COVID-19 and the price war between Saudi Arabia and Russia. Combined with the decrease in WTI was a widening of the condensate differential from a discount of US\$3.96 per barrel in the second quarter of 2019 to a discount of US\$5.54 per barrel in the second quarter of 2020.

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

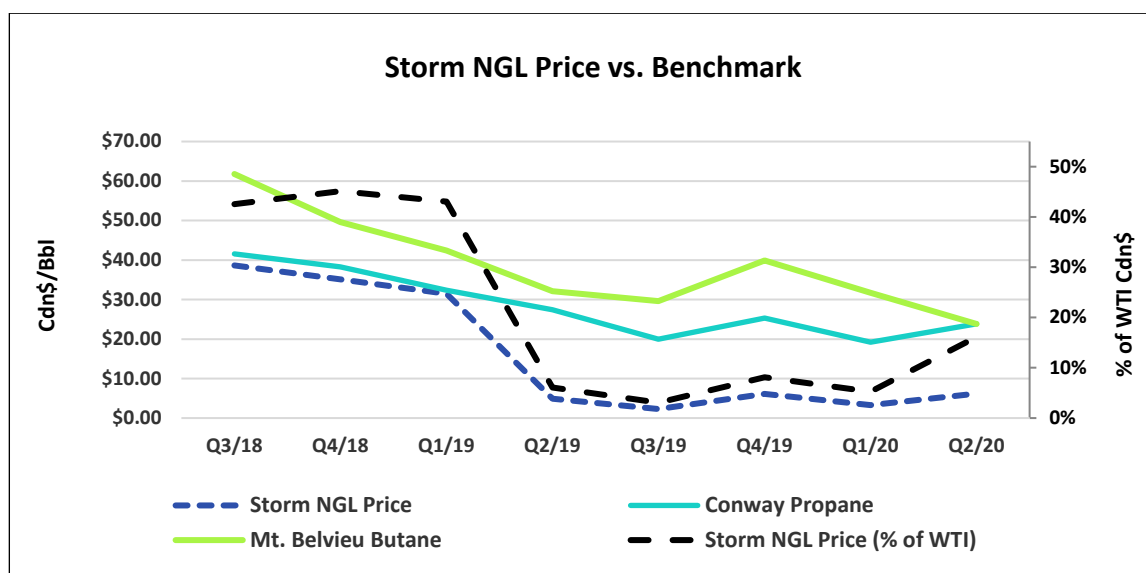
	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Chicago monthly index price	41%	43%	29%	39%
Chicago daily index price	15%	13%	24%	16%
AECO index price	17%	9%	12%	10%
BC Station 2 index price	12%	21%	18%	21%
Sumas index price	10%	12%	11%	11%
Alliance Transfer Point ("ATP")	5%	2%	6%	3%
Total	100%	100%	100%	100%



In the second quarter of 2020, Storm's realized natural gas price decreased to a 13% premium to BC Station 2 pricing compared to a 347% premium for the second quarter of 2019. The decrease was from selling approximately 66% of the Company's natural gas into the Chicago and Sumas markets where pricing decreased, while AECO and BC Station 2 prices increased.



Storm's realized condensate price of \$25.92 per barrel for the second quarter of 2020 decreased by 64% from the second quarter of 2019 as a result of a 53% decrease in the WTI price combined with widening of the WTI-Edmonton condensate differential from a discount of US\$3.96 per barrel in the second quarter of 2019 to a discount of US\$5.54 per barrel in the second quarter of 2020.



Storm's realized price for NGL, excluding condensate, in the second quarter of 2020 increased by 28% relative to the same period of 2019 due to higher contracted prices with marketers partially offset by lower WTI pricing. When comparing the first six months of 2020 to the same period of 2019, the realized price for NGL, excluding condensate, decreased by 72%. The decrease in realized NGL prices for the first half of 2020 was primarily due to lower contracted prices with marketers, lower propane pricing and weaker WTI pricing period over period.

Storm's NGL price net of transportation is anticipated to be approximately 15% to 20% of WTI in Canadian dollar terms for the contract period that commenced in April 2020 and ends in March 2021. This has been revised upwards from the 10% to 15% range previously announced as a result of improving propane pricing (Far East Asia Index and Conway).

Realized Gain (Loss) on Risk Management

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Natural gas	\$ 1,659	\$ (166)	\$ 3,383	\$ (10,088)
Liquids ⁽¹⁾	4,854	(241)	5,867	88
Realized gain (loss) on risk management contracts	\$ 6,513	\$ (407)	\$ 9,250	\$ (10,000)
Per Boe	\$ 2.99	\$ (0.22)	\$ 2.12	\$ (2.78)

(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 WTI 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 during the reporting period. The realized gains of \$6.5 million and \$9.3 million for the three and six months ended June 30, 2020, respectively, are primarily due to lower WTI crude oil pricing combined with lower natural gas pricing at Chicago and Sumas.

Royalties

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period	\$ 949	\$ 577	\$ 3,056	\$ 5,234
Percentage of revenue from product sales	3.1%	1.5%	4.2%	5.6%
Per Boe	\$ 0.44	\$ 0.32	\$ 0.70	\$ 1.46

Royalties, as a percentage of revenue from product sales, in the second quarter of 2020, increased compared to the same period in 2019 primarily due to the receipt of infrastructure royalty credits of \$1.6 million in the second quarter of 2019 which was partially offset by lower realized commodity prices. In the second quarter of 2020, 29 wells qualified for the minimum 6% royalty rate on new horizontal wells compared to 27 wells in the second quarter of 2019. The BC Deep Well Royalty Credit Program reduces the royalty rate on new horizontal wells to 6% for approximately one to three years depending on productivity and commodity prices.

Royalties, as a percentage of revenue from product sales, decreased in the six months ended June 30, 2020 compared to the same period in 2019 primarily due to a decrease in realized commodity prices partially offset by receipt of infrastructure royalty credits in 2019.

Storm has remaining infrastructure royalty credits of \$7.0 million that will reduce future royalties including credits of \$6.2 million relating to the construction of the Nig Creek Gas Plant which came online in February 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 realized.

Production Costs

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period	\$ 9,792	\$ 10,681	\$ 21,051	\$ 21,543
Per Boe	\$ 4.50	\$ 5.89	\$ 4.83	\$ 5.99

Total production costs for the second quarter and first six months of 2020 decreased by 8% and 2%, respectively, when compared to the same periods of 2019 and decreased by 24% and 19%, respectively, on a per-Boe basis. The decrease in total production costs for the second quarter and first half of 2020 compared to the second quarter and first half of 2019 is primarily due to lower third-party gas processing costs as a result of the start-up of the Nig Creek Gas Plant in February 2020, partially offset by higher production volumes. Production costs on a per-Boe basis in 2019 were also affected by outages which reduced production volumes in the period.

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 within production costs.

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period	\$ 1,511	\$ 1,476	\$ 3,171	\$ 2,827
Per Boe	\$ 0.69	\$ 0.81	\$ 0.73	\$ 0.79

Transportation Costs

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period	\$ 11,982	\$ 10,808	\$ 22,816	\$ 21,014
Per Boe	\$ 5.50	\$ 5.96	\$ 5.24	\$ 5.84

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 second quarter of 2020 increased by 11% when compared to the second quarter of 2019 primarily due to higher production volumes in 2020. On a per-Boe basis, transportation costs for the second quarter of 2020 decreased by 8% when compared to the second quarter of 2019 primarily due to incurring fixed costs in the prior year for unused firm transportation during the outages.

Transportation costs for the first six months of 2020 increased by 9% when compared to the same period in 2019 primarily due to higher production volumes in 2020. Transportation costs for the first six months of 2020 decreased by 10% on a per-Boe basis when compared to the same period of 2019, primarily due to incurring fixed costs for unused firm transportation during outages.

Field Operating Netbacks

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

	Three Months to June 30, 2020			
	Natural Gas ⁽¹⁾ (\$/Mcf)	Condensate ⁽²⁾ (\$/Bbl)	NGL (\$/Bbl)	Total (\$/Boe)
Revenue from product sales	2.23	25.92	6.23	13.86
Royalties	(0.04)	(1.52)	(0.97)	(0.44)
Production costs	(0.94)	-	-	(4.50)
Transportation costs	(1.02)	(6.15)	(0.36)	(5.50)
Field operating netback	0.23	18.25	4.90	3.42
Realized gain (loss) on risk management contracts	0.16	23.14	-	2.99
Field operating netback including hedging	0.39	41.39	4.90	6.41

	Three Months to June 30, 2019			
	Natural Gas ⁽¹⁾ (\$/Mcf)	Condensate ⁽²⁾ (\$/Bbl)	NGL (\$/Bbl)	Total (\$/Boe)
Revenue from product sales	2.64	71.12	4.87	20.72
Royalties	0.13	(8.55)	(0.70)	(0.32)
Production costs	(1.20)	-	-	(5.89)
Transportation costs	(1.10)	(5.42)	(0.24)	(5.96)
Field operating netback	0.47	57.15	3.93	8.55
Realized gain (loss) on risk management contracts	(0.02)	(2.76)	1.94	(0.22)
Field operating netback including hedging	0.45	54.39	5.87	8.33

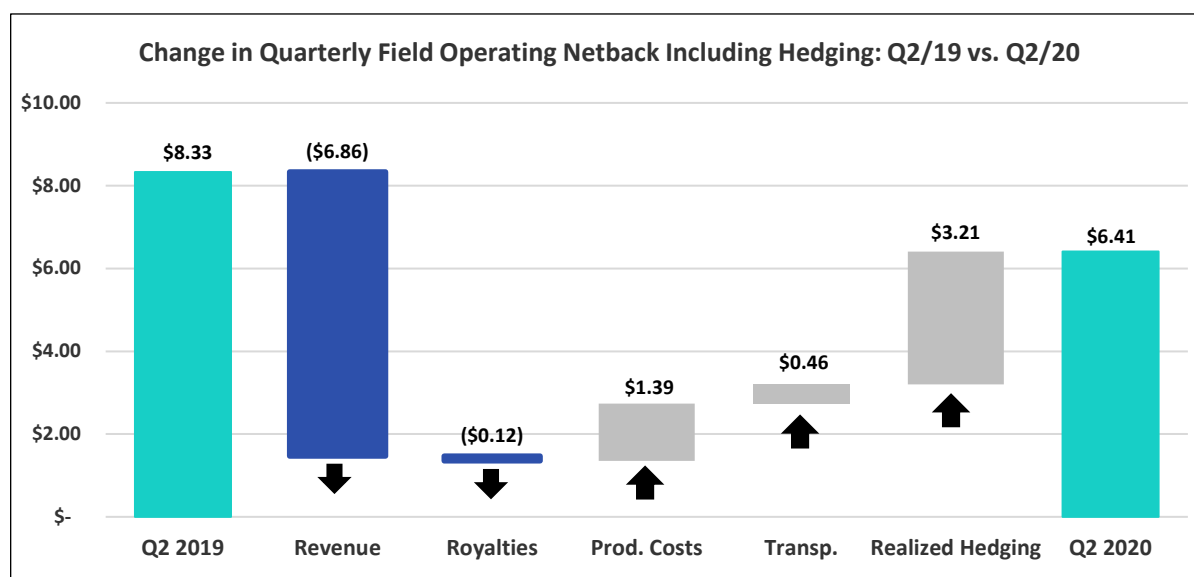
	Six Months to June 30, 2020			
	Natural Gas ⁽¹⁾ (\$/Mcf)	Condensate ⁽²⁾ (\$/Bbl)	NGL (\$/Bbl)	Total (\$/Boe)
Revenue from product sales	2.39	44.41	4.92	16.55
Royalties	(0.05)	(3.92)	(0.70)	(0.70)
Production costs	(1.00)	-	-	(4.83)
Transportation costs	(0.96)	(5.44)	(0.44)	(5.24)
Field operating netback	0.38	35.05	3.78	5.78
Realized gain (loss) on risk management contracts	0.16	13.08	-	2.12
Field operating netback including hedging	0.54	48.13	3.78	7.90

	Six Months to June 30, 2019			
	Natural Gas ⁽¹⁾ (\$/Mcf)	Condensate ⁽²⁾ (\$/Bbl)	NGL (\$/Bbl)	Total (\$/Boe)
Revenue from product sales	3.55	66.85	17.83	25.95
Royalties	(0.08)	(8.17)	(2.51)	(1.46)
Production costs	(1.23)	-	-	(5.99)
Transportation costs	(1.08)	(5.25)	(0.12)	(5.84)
Field operating netback	1.16	53.43	15.20	12.66
Realized gain (loss) on risk management contracts	(0.57)	(0.99)	1.67	(2.78)
Field operating netback including hedging	0.59	52.44	16.87	9.88

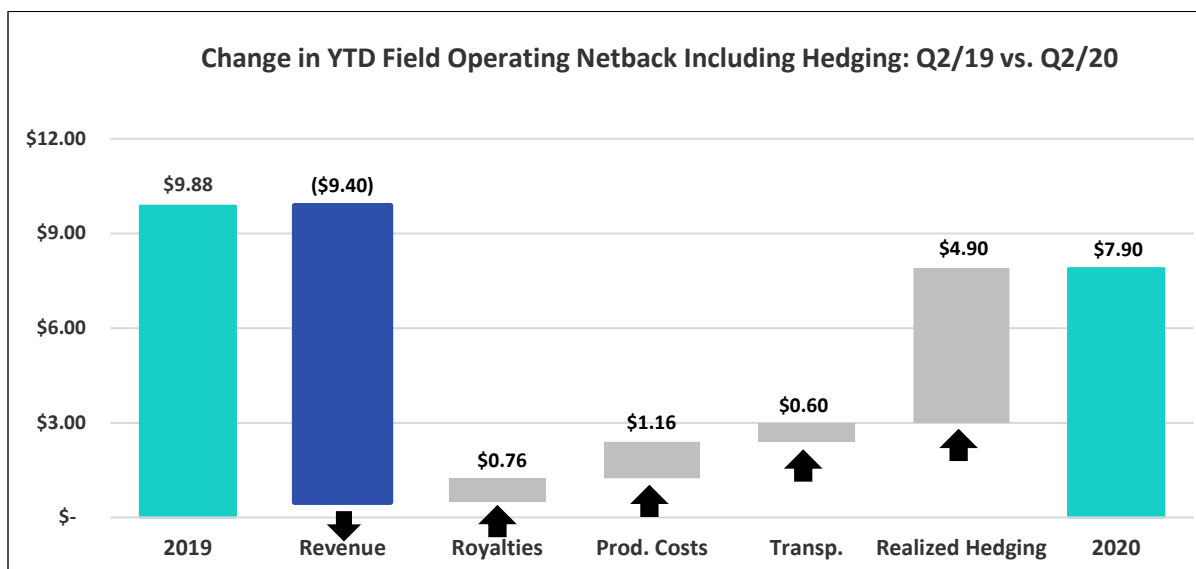
(1) Production costs of condensate and NGL are included within natural gas costs.

(2) Realized gains and losses on crude oil contracts are included within the condensate netback.

The field operating netback for the second quarter of 2020 decreased by 23% after hedging compared to the second quarter of 2019. The increase in realized hedging is due to a realized hedging loss of \$0.22 per Boe in the second quarter of 2019 compared to a realized hedging gain of \$2.99 per Boe in the second quarter of 2020. The realized hedging gain partially offset decreases in revenue as a result of lower benchmark pricing for crude oil and natural gas.



The field operating netback for the first six months of 2020 decreased by 20% after hedging compared to the first six months of 2019. The increase in realized hedging is due to a realized hedging loss of \$2.78 per Boe in the first six months of 2019 compared to a realized gain of \$2.12 per Boe in the first six months of 2020.



General and Administrative Costs

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period – before recoveries	\$ 1,730	\$ 1,860	\$ 4,297	\$ 5,104
Overhead recoveries	(160)	(632)	(860)	(1,025)
Charge for period – net of recoveries	\$ 1,570	\$ 1,228	\$ 3,437	\$ 4,079
Per Boe	\$ 0.72	\$ 0.68	\$ 0.79	\$ 1.13

General and administrative costs before recoveries for the second quarter of 2020 were largely unchanged when compared to the second quarter of 2019. General and administrative costs before recoveries for the six months ended June 30, 2020 decreased by 16% compared to the same period of 2019 primarily due to the employee performance bonus in 2020 being lower than in 2019.

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

Net general and administrative costs on a per-Boe measure for the second quarter of 2020 were higher by 6% compared to the second quarter of 2019 due to a decrease in overhead recoveries as a result of lower capital expenditures, partially offset by higher production volumes. Net general and administrative costs on a per-Boe basis decreased by 30% when comparing the first six months of 2020 to the same period of 2019 due to the aforementioned decrease in the employee performance bonus and higher production volumes. 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 June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period ⁽¹⁾	\$ 1,519	\$ 1,315	\$ 3,165	\$ 2,433
Average interest rate ⁽²⁾	4.7%	5.7%	5.0%	5.1%
Per Boe	\$ 0.70	\$ 0.73	\$ 0.73	\$ 0.68

(1) Includes lease interest.

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

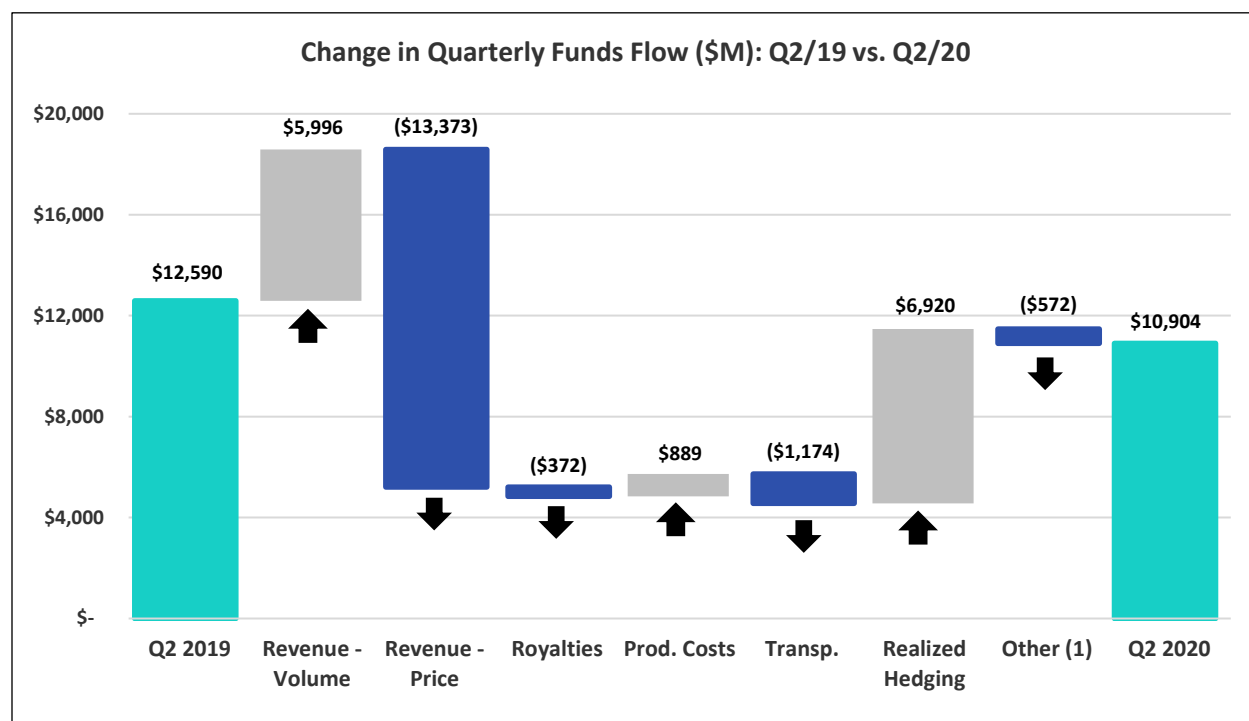
The interest rate on the Company's bank facility is based on bankers' acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the second quarter and first six months of 2020 increased by 16% and 30%, respectively, compared to the same periods of 2019 as a result of higher average bank borrowings which were used to fund construction of the Nig Creek Gas Plant.

Funds Flow

	Three Months to June 30, 2020		Three Months to June 30, 2019		Six Months to June 30, 2020		Six Months to June 30, 2019	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	\$10,904	\$0.09	\$12,590	\$0.10	\$27,793	\$0.23	\$29,107	\$0.24

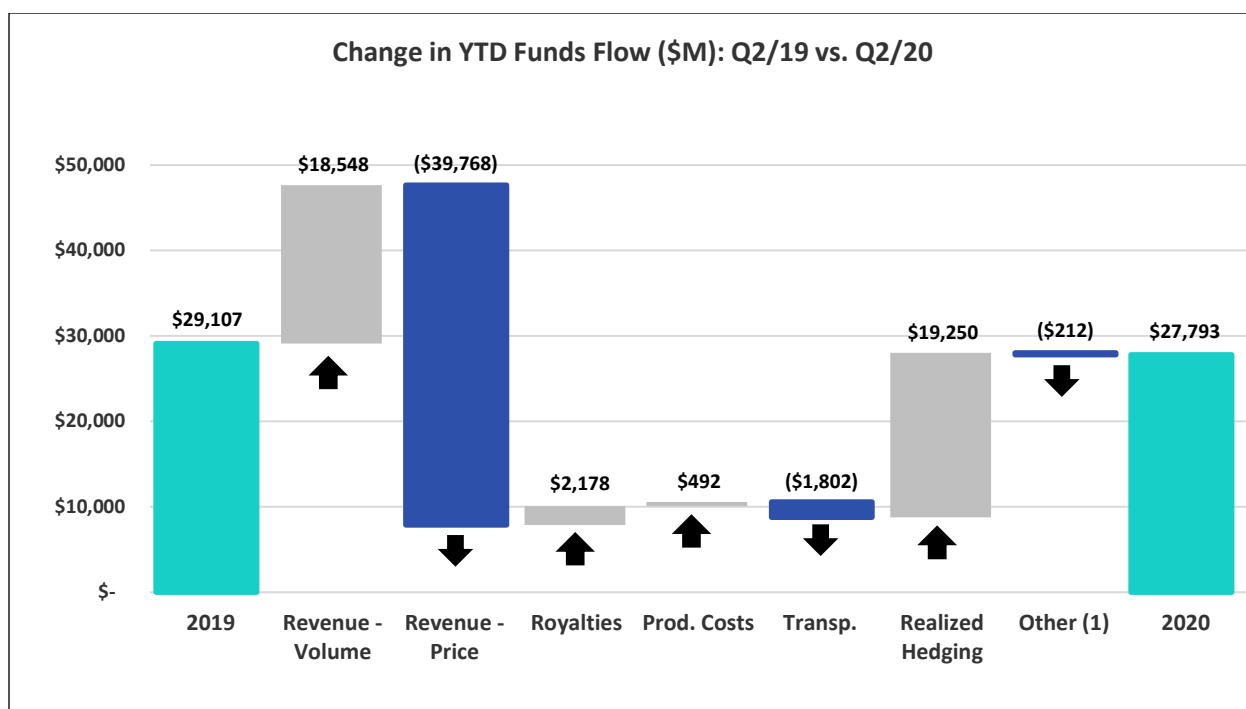
Funds flow, a measure that is not defined under IFRS, is cash generated from operating activities before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies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



(1) Includes general and administrative cost, interest and finance costs and decommissioning expenditures and excludes lease interest.

Lower realized prices partially offset by higher production volumes and hedging gains were the predominant factors in the 13% decrease in funds flow in the second quarter of 2020 versus the second quarter of 2019.

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 12% in the second quarter of 2020 compared to 18% in the second quarter of 2019.



(1) Includes general and administrative cost, interest and finance costs and decommissioning expenditures and excludes lease interest.

Funds flow for the first six months of 2020 decreased by 5% from the first six months of 2019. Funds flow was negatively affected by weaker realized pricing, partially offset by higher production volumes.

Share-Based Compensation

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Charge for period	\$ 428	\$ 564	\$ 904	\$ 1,160
Per Boe	\$ 0.20	\$ 0.31	\$ 0.21	\$ 0.32

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 24% in the second quarter of 2020 compared to the second quarter of 2019 and decreased by 22% when comparing the six month periods. The decrease in share-based compensation in both the three and six month periods is primarily attributable to a lower stock option fair valuation associated with options granted during 2019.

Depletion and Depreciation

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Depletion	\$ 9,260	\$ 8,040	\$ 19,039	\$ 15,892
Depreciation	2,593	1,914	4,819	3,808
Charge for period	\$ 11,853	\$ 9,954	\$ 23,858	\$ 19,700
Per Boe	\$ 5.44	\$ 5.49	\$ 5.48	\$ 5.48

Depletion and depreciation increased by 19% in the second quarter of 2020 compared to the same quarter of 2019, and by 21% when comparing the six month periods, primarily due to an increase in production volumes.

Unrealized Gain (Loss) on Risk Management

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Natural gas	\$ (4,834)	\$ 7,681	\$ (5,456)	\$ 9,962
Liquids ⁽¹⁾	(8,993)	2,042	3,280	(5,047)
Interest rate	3	(98)	(1,171)	(98)
Unrealized gain (loss) on risk management contracts	\$ (13,824)	\$ 9,625	\$ (3,347)	\$ 4,817
Per Boe	\$ (6.35)	\$ 5.31	\$ (0.77)	\$ 1.34

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

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.

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. In 2020, the time frame was revised and the rate was reduced to 8% effective July 1, 2020, although this revision has yet to be substantively enacted.

The Company did not incur any cash tax expense in the three and six months ended June 30, 2020, nor does it expect to pay any cash tax in the remainder of 2020 or in 2021 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 six months ended June 30, 2020, the Company recognized a deferred income tax recovery of \$3.7 million and a deferred income tax expense of \$0.2 million, respectively, as a result of \$15.4 million and \$1.0 million of net loss before taxes, respectively. As at June 30, 2020, the Company had a deferred income tax liability of \$9.5 million.

Tax Pools	As at June 30, 2020	Maximum Annual Deduction
Canadian oil and gas property expense	\$ 41,000	10%
Canadian development expense	108,000	30%
Canadian exploration expense	14,000	100%
Undepreciated capital cost	134,000	20% - 100%
Operating losses	207,000	100%
Total	\$ 504,000	

Net Income (Loss)

The mark-to-market valuation of risk management contracts resulted in a considerable distortion on reported net loss for the three and six months ended June 30, 2020 relative to the comparable periods in 2019. For the three and six months ended June 30, 2020, the unrealized loss on risk management contracts amounted to \$13.8 million and \$3.3 million, respectively, compared to an unrealized gain for the three and six months ended June 30, 2019 of \$9.6 million and \$4.8 million, respectively.

Excluding unrealized gains and losses on risk management contracts, the increase in net loss in the three and six months ended June 30, 2020 compared to the same periods of 2019 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 2% in the second quarter of 2020 compared to 11% in the second quarter of 2019, although as mentioned above is distorted by unrealized gains and losses on the Company's risk management contracts.

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Net income (loss)	\$ (11,665)	\$ 7,864	\$ (1,153)	\$ 8,471
Per basic and diluted share	\$ (0.10)	\$ 0.06	\$ (0.01)	\$ 0.07

Corporate Netbacks

(\$/Boe)	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Revenue from product sales	13.86	20.72	16.55	25.95
Realized gain (loss) on risk management contracts	2.99	(0.22)	2.12	(2.78)
Royalties	(0.44)	(0.32)	(0.70)	(1.46)
Production	(4.50)	(5.89)	(4.83)	(5.99)
Transportation	(5.50)	(5.96)	(5.24)	(5.84)
General and administrative	(0.72)	(0.68)	(0.79)	(1.13)
Interest and finance costs	(0.68)	(0.71)	(0.71)	(0.66)
Decommissioning expenditures	(0.01)	-	(0.03)	-
Funds flow	5.00	6.94	6.37	8.09
Share-based compensation	(0.20)	(0.31)	(0.21)	(0.32)
Depletion, depreciation and accretion	(5.48)	(5.56)	(5.52)	(5.55)
Lease interest	(0.02)	(0.02)	(0.02)	(0.02)
Exploration and evaluation costs expensed	-	(0.62)	(0.10)	(0.31)
Unrealized revaluation gain (loss) on investments	(0.03)	-	(0.02)	-
Unrealized gain (loss) on risk management contracts	(6.35)	5.31	(0.77)	1.34
Decommissioning expenditures	0.01	-	0.03	-
Deferred income tax (expense) recovery	1.70	(1.41)	(0.03)	(0.87)
Net income (loss)	(5.37)	4.33	(0.27)	2.36

INVESTMENT AND FINANCING

Financial Resources and Liquidity

As at June 30, 2020, the Company had an extendible revolving credit facility in the amount of \$190 million (December 31, 2019 - \$205 million) based on a bank determined borrowing base related to the Company's producing reserves. Although the borrowing base was set at \$205 million, the Company voluntarily reduced the credit facility amount to \$190 million in order to reduce the associated fees. The credit facility is available to the Company until May 28, 2021, 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 June 30, 2020, debt including outstanding letters of credit amounted to \$142.7 million, representing approximately 75% of the available credit facility.

As at June 30, 2020, the Company had issued letters of credit in the amount of \$13.3 million (December 31, 2019 - \$10.0 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 second quarter of 2020, the Company incurred capital expenditures of \$2.4 million compared to \$23.1 million in the second quarter of 2019.

In the first six months of 2020, the Company incurred capital expenditures of \$28.9 million (first six months of 2019 - \$40.1 million) primarily related to costs incurred for completion and start-up of the Nig Creek Gas Plant (\$12.0 million), as well as drilling two horizontal wells (1.0 net) and completing one well (0.5 net) at Fireweed, and completion, tie-in and equipping activities on three wells (3.0 net) at Umbach.

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Land and seismic	\$ 101	\$ 952	\$ 334	\$ 1,535
Drilling	324	-	4,003	11,308
Completions	290	7,931	9,966	7,954
Facilities	1,673	13,886	12,882	17,867
Equipping and pipelines	-	371	1,553	1,329
Recompletions and workovers	-	4	87	49
Property acquisition and administrative assets	6	1	44	47
Total capital expenditures	\$ 2,394	\$ 23,145	\$ 28,869	\$ 40,089

Net capital investment was allocated as follows:

	Three Months to June 30, 2020	Three Months to June 30, 2019	Six Months to June 30, 2020	Six Months to June 30, 2019
Exploration and evaluation	\$ 101	\$ 952	\$ 334	\$ 1,535
Property and equipment	2,293	22,193	28,535	38,554
Total capital expenditures	\$ 2,394	\$ 23,145	\$ 28,869	\$ 40,089

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at June 30, 2020 corresponds to the Company's limited field program.

Decommissioning Liability

The Company's decommissioning liability of \$30.4 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 June 30, 2020 was \$35.4 million (December 31, 2019 - \$38.3 million), with \$1.1 million expected to be incurred in the next 12 months. The liability for currently inactive wells and facilities is approximately \$10 million with approximately 75% of this expected to be incurred by 2025.

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 \$4.5 million over six years. In addition, as at the date of this report, the Company has transportation and processing commitments valued at a total of approximately \$409 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 30, 2020 appears below.

	2020		2019				2018	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(\$000s unless otherwise stated)								
Revenue from product sales	30,191	41,923	48,671	31,417	37,568	55,766	74,799	51,253
Funds flow	10,904	16,889	18,469	11,973	12,590	16,517	30,941	22,227
Per share – basic and diluted (\$)	0.09	0.14	0.15	0.10	0.10	0.14	0.25	0.18
Net income (loss)	(11,665)	10,512	2,906	(64)	7,864	607	26,810	7,174
Per share – basic and diluted (\$)	(0.10)	0.09	0.02	(0.00)	0.06	0.00	0.22	0.06
Net capital expenditures	2,394	26,475	23,913	32,841	23,145	16,944	37,100	21,845
Average daily production (Boe)	23,935	23,946	22,375	18,596	19,923	19,823	22,432	20,455
Debt including working capital deficiency ⁽¹⁾	130,317	138,632	128,901	123,342	102,268	91,585	91,020	84,648

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

LIMITATIONS

Forward-Looking Statements – Certain forward-looking information and statements are set forth in this document, including management's assessment of Storm's future plans and operations specifically in relation to 2020 and 2021, and contain 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", "schedule", "indicate", "focus", "outlook", "propose", "target", "objective", "priority", "strategy", "estimate", "budget", "forecast", "would", "could", "will", "may", "future" or other similar words or expressions and include statements relating to or associated with individual wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations and financial position. Forward-looking statements are based on expectations, forecasts, and assumptions made by the Company using information available at the time of the statement and historical trends which includes expectations and assumptions concerning: the accuracy of reserve estimates and valuations; performance characteristics of producing properties; access to third-party infrastructure; government policies and regulation; future production rates; accuracy of estimated capital expenditures; availability and cost of labour and services and owned or third-party infrastructure; royalties; development and execution of projects; the satisfaction by third parties of their obligations to the Company; and the receipt and timing for approvals from regulators and third parties. All statements and information concerning expectations or projections about the future and statements and information regarding the future business plan or strategy, timing or scheduling, production volumes with splits by commodity, production declines, expected and future activities and capital expenditures, commodity prices, costs, royalties, schedules, operating or financial results, future financing requirements, and the expected effect of future commitments are forward-looking statements.

Forward-looking statements include references to:

- future production volumes in 2020 and 2021, production volumes by commodity and production declines;
- capital investment intended to be approximately equal to funds flow;
- planned capital expenditures in 2020 totaling \$52 to \$60 million, timing, allocations to specific areas, and the availability of financial resources to fund which includes cash and cash equivalents, funds flow, and availability of committed credit facilities;
- future capital expenditures and their allocation to specific activities or periods, particularly with respect to estimated capital investment required to maintain production and number of wells to be drilled and completed as part of the 2020 capital program;

- the expected improvement in the Company's NGL price in 2020;
- the near-term growth plan for 2020 and 2021 which is expected to increase liquids as a proportion of total production and decrease per-Boe production costs and includes the estimated start date of production from the Fireweed area based on timing for completion of the field compression facility and timing for the drilling and completion of wells;
- future tax liabilities and future use of tax pools and losses;
- estimates of ultimate recovery from wells including management's references to type curves; and
- existing or future contractual obligations including agreements pertaining to processing capacity, transportation and marketing of natural gas, condensate and NGL.

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, but are not limited to:

- changes in general, market and business conditions including commodity prices, interest rates and currency exchange;
- changes in supply and demand for the Company's products;
- a global public health crisis including the recent outbreak of the novel coronavirus (COVID-19) which causes volatility and disruptions in the supply, demand and pricing for natural gas, oil and NGL, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people;
- the ability to obtain regulatory, stakeholder and third-party approvals and satisfy any associated conditions that are not within the Company's control for exploration and development activities and projects;
- successful and timely implementation of capital expenditures;
- risks associated with the development and execution of major projects;
- risk that projects and opportunities intended to grow funds flow and/or reduce costs may not achieve the expected results in the time anticipated or at all;
- access to third-party pipelines and facilities and access to sales markets;
- volatility of commodity prices and the related effects of changing price differentials;
- the Company's ability to operate and run its facilities to meet forecast production;
- the output of newly commissioned facilities which may be difficult to accurately predict at an early stage;
- operational risks and uncertainties associated with oil and gas activities including unexpected formations or pressures, reservoir performance, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of natural gas and wellbore fluids, pollution and other environmental risks;
- changes in costs including production, royalty, transportation, general and administrative, and finance;
- ability to finance planned activities including infrastructure expansions which are required to meet future growth targets;
- adverse weather conditions which could disrupt production and affect drilling and completions resulting in increased costs and/or delay adding production;
- actions by government authorities including changes to taxes, fees, royalties, duties and government-imposed compliance costs;
- changes to laws and government policies including environmental (and climate change), royalty, and tax laws and policies;
- counter-party risk with third parties to perform their obligations with whom the Company has material relationships;
- unplanned facility maintenance or outages or unavailability of third-party infrastructure which could reduce production or prevent the transportation of products to processing plants and sales markets;
- a major outage or environmental incident or unexpected event such as fires (including forest fires) or equipment failures or similar events that would affect the Company's facilities or third-party infrastructure used by the Company;
- environmental risks (including climate change) and the cost of compliance with current and future environmental laws, including climate change laws along with risks relating to increased activism and opposition to fossil fuels;
- ability to access capital from internal and external sources (including the credit facility);
- the risk that competing business objectives may exceed Storm's capacity to adapt and implement change;
- the potential for security breaches of the Company's information technology systems by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches;
- risks with transactions including closing an asset or property acquisition or disposition and the failure to realize anticipated benefits from any transaction;
- finding new oil and gas reserves that can be developed economically to replace reserves depleted by production;

- the accuracy of estimating reserves and future production and the future value of reserves;
- risk associated with commodity price hedging activities using derivatives and other financial instruments;
- maintaining debt levels at a reasonable multiple of funds flow;
- risk with First Nations land claims and consultation requirements;
- risk that the Company may be subject to litigation;
- the accuracy of cost estimates, some of which are provided at an early stage and before detailed engineering has been completed;
- risk associated with partner or joint venture arrangements to which the Company is a party;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- increased competition from other industry participants for, among other things, capital, acquisitions of assets or undeveloped lands, and skilled personnel; and
- increased competition from companies that provide alternative sources of energy.

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

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 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.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained herein 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, decommissioning liability and lease liability. 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 June 30, 2020	As at June 30, 2019	As at June 30, 2018
Accounts receivable	10,788	10,982	11,490
Prepays and deposits	634	387	688
Less: Accounts payable and accrued liabilities	(12,381)	(29,065)	(9,944)
Working capital deficiency (surplus)	959	17,696	(2,234)
Bank indebtedness	129,358	84,572	87,307
Debt including working capital deficiency	130,317	102,268	85,073

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 June 30, 2020	Twelve Months Ended June 30, 2019
Average debt including working capital deficiency ⁽¹⁾	116,293	93,671
Average shareholders' equity ⁽¹⁾	419,511	394,924
Average capital employed	535,804	488,595
Funds flow	58,235	82,275
Interest and finance costs	5,890	4,279
Funds flow plus interest and finance costs	64,125	86,554
CROCE	12%	18%

(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 following table.

(\$000s unless otherwise stated)	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2019
Average debt including working capital deficiency ⁽¹⁾	116,293	93,671
Average shareholders' equity ⁽¹⁾	419,511	394,924
Average capital employed	535,804	488,595
Net income (loss)	1,689	42,455
Interest and finance costs	5,890	4,279
Deferred income tax expense	1,958	7,562
	9,537	54,296
ROCE	2%	11%

(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 30, 2020 for the year ended December 31, 2019 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2019 under the heading "Business Risks".

Crude Oil and Natural Gas Prices and General Economic Conditions

The Company's financial results are largely dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices are subject to fluctuations in supply, demand, market uncertainty and other factors that are beyond the Company's control. This can include but is not limited to: the global and domestic supply of and demand for crude oil and natural gas; global and North American economic conditions; the actions of OPEC or individual producing nations; government regulation; political stability; the ability to transport commodities to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude oil and natural gas production in Western Canada and the United States has resulted in pressure on transportation and pipeline capacity which contributes to fluctuations in prices. All of these factors are beyond the Company's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. The Company's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges.

Fluctuations in the price of commodities and associated price differentials affect the value of the Company's assets and the Company's ability to pursue its business objectives. Prolonged periods of low commodity prices and volatility may also affect the Company's ability to meet guidance targets and its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas could have an adverse effect on the Company's reserves, borrowing capacity, revenues, profitability and funds flow and may have a material adverse effect on the Company's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves. This may include delay or cancellation of existing or future drilling or development programs or curtailment in production as the economics of producing from some wells may become impaired.

In addition, bank borrowings available to the Company are, in part, determined by the value of the Company's assets. A sustained material decline in commodity prices from historical average prices could reduce the value of the Company's assets, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid, as well as curtailment of the Company's investment programs.

The Company conducts regular assessments of the carrying amount of its assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying amount of the Company's assets may be subject to impairment.

Market conditions which include global oil and natural gas supply and demand and recent events including actions taken by OPEC, Russia's recent withdrawal from OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, isolationist and punitive trade policies, shale production in the United States, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, curtailment of production of crude oil by the Government of Alberta, the outbreak of COVID-19 and the price war between Saudi Arabia and Russia have caused significant volatility in commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks, including attacks on oil infrastructure in oil producing nations, in the United States or other countries could adversely affect the economies of Canada, the United States and other countries. These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the future of the oil and natural gas industry. In addition, the difficulties encountered by midstream proponents in Western Canada to obtain the necessary approvals on a timely basis to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and natural gas industry has led to additional downward pressure on oil and natural gas prices which has further reduced confidence in the oil and natural gas industry in Western Canada.

Global Health Crises

The Company's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China; on January 30, 2020, the WHO declared the outbreak a global health emergency; and on March 11, 2020 the WHO declared the outbreak of COVID-19 a global pandemic. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Canada, the United States, Europe and the Middle East with cases of COVID-19 increasing around the world. The spread of COVID-19 has led companies and various jurisdictions to impose restrictions such as quarantines, business closures and domestic and international travel restrictions. The duration of the business disruptions internationally and related financial effect cannot be reasonably

estimated at this time. Similarly, the Company cannot estimate whether or to what extent this pandemic and the potential financial effect may extend to countries outside of those currently affected.

Such public health crises can result in volatility and disruptions in the supply, demand and pricing for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, crude oil prices have significantly weakened in response to the outbreak of COVID-19. The risks to the Company of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations affected by an outbreak. This could include the Company's wells and facilities and/or third-party facilities and pipelines used by the Company. At this point, the extent to which COVID-19 may affect the Company is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Company's business, results of operations and financial condition.

FINANCIAL REPORTING UPDATE

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 June 30, 2020 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.

QUARTERLY SUMMARIES

Thousands of Cdn\$, except volumetric and per-share amounts	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018
FINANCIAL								
Revenue from product sales ⁽¹⁾	30,191	41,923	48,671	31,417	37,568	55,766	74,799	51,253
Funds flow	10,904	16,889	18,469	11,973	12,590	16,517	30,941	22,227
Per share - basic and diluted (\$)	0.09	0.14	0.15	0.10	0.10	0.14	0.25	0.18
Net income (loss)	(11,665)	10,512	2,906	(64)	7,864	607	26,810	7,174
Per share - basic and diluted (\$)	(0.10)	0.09	0.02	(0.00)	0.06	0.00	0.22	0.06
Cash return on capital employed ("CROCE") ⁽²⁾	12%	12%	12%	15%	18%	20%	21%	21%
Return on capital employed ("ROCE") ⁽²⁾	2%	7%	4%	9%	11%	8%	10%	6%
Capital expenditures	2,394	26,475	23,913	32,841	23,145	16,944	37,100	21,845
Debt including working capital deficiency ⁽²⁾⁽³⁾	130,317	138,632	128,901	123,342	102,268	91,585	91,020	84,648
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	121,557	121,557	121,557	121,853	121,649	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⁾	13.86	19.24	23.64	18.36	20.72	31.26	36.24	27.24
Transportation costs	(5.50)	(4.97)	(5.20)	(5.83)	(5.96)	(5.72)	(5.57)	(5.98)
Revenue net of transportation	8.36	14.27	18.44	12.53	14.76	25.54	30.67	21.26
Royalties	(0.44)	(0.97)	(1.59)	0.19	(0.32)	(2.61)	(0.58)	(1.03)
Production costs	(4.50)	(5.17)	(5.67)	(5.88)	(5.89)	(6.09)	(5.46)	(5.54)
Field operating netback ⁽²⁾	3.42	8.13	11.18	6.84	8.55	16.84	24.63	14.69
Realized gain (loss) on risk management contracts	2.99	1.26	(0.80)	1.64	(0.22)	(5.38)	(8.65)	(1.73)
General and administrative	(0.72)	(0.86)	(0.70)	(0.79)	(0.68)	(1.60)	(0.55)	(0.66)
Interest and finance costs	(0.68)	(0.74)	(0.71)	(0.69)	(0.71)	(0.61)	(0.45)	(0.49)
Decommissioning expenditures	(0.01)	(0.04)	-	-	-	-	-	-
Funds flow per Boe	5.00	7.75	8.97	7.00	6.94	9.25	14.98	11.81
Barrels of oil equivalent per day (6:1)	23,935	23,946	22,375	18,596	19,923	19,823	22,432	20,455
Natural gas production								
Thousand cubic feet per day	114,772	115,957	108,679	91,053	97,510	96,537	109,520	101,905
Price (Cdn\$ per Mcf) ⁽¹⁾	2.23	2.54	3.28	2.42	2.64	4.49	5.56	3.21
Condensate production								
Barrels per day	2,305	2,623	2,416	1,856	2,081	2,199	2,453	2,059
Price (Cdn\$ per barrel) ⁽¹⁾	25.92	60.66	66.56	63.45	71.12	62.77	58.74	84.97
NGL production								
Barrels per day	2,501	1,998	1,846	1,564	1,591	1,534	1,726	1,412
Price (Cdn\$ per barrel) ⁽¹⁾	6.23	3.27	6.11	2.29	4.87	31.43	35.09	38.64
Wells drilled (net)	-	1.0	-	1.0	-	5.0	4.0	-
Wells completed (net)	-	3.5	-	5.0	-	-	2.5	5.0

(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 25 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, decommissioning liability and lease liability.

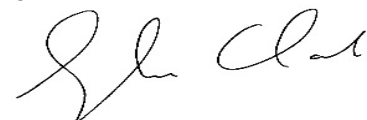
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

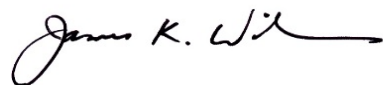
(Canadian \$000s) (unaudited)	Notes	June 30, 2020	December 31, 2019
ASSETS			
Current			
Accounts receivable	12	\$ 10,788	\$ 21,961
Prepays and deposits		634	764
Risk management contracts	12	-	1,113
		11,422	23,838
Exploration and evaluation	3	99,630	99,737
Property and equipment	4	497,351	490,264
Right-of-use asset	7	2,439	2,657
		\$ 610,842	\$ 616,496
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current			
Accounts payable and accrued liabilities		\$ 12,381	\$ 30,018
Current portion of decommissioning liability	8	1,144	448
Current portion of lease liability	7	509	507
Risk management contracts	12	2,554	2,042
		16,588	33,015
Bank indebtedness	5	129,358	121,608
Risk management contracts	12	2,626	904
Lease liability	7	2,046	2,234
Decommissioning liability	8	29,245	27,667
Deferred income taxes		9,520	9,360
		\$ 189,383	194,788
Shareholders' equity			
Share capital	9	391,444	391,444
Contributed surplus	10	18,509	17,605
Retained earnings		11,506	12,659
		421,459	421,708
Commitments	14		
		\$ 610,842	\$ 616,496

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 June 30		Six Months Ended June 30	
		2020	2019	2020	2019
Revenue					
Revenue from product sales	6	\$ 30,191	\$ 37,568	\$ 72,114	\$ 93,334
Royalties		(949)	(577)	(3,056)	(5,234)
		29,242	36,991	69,058	88,100
Realized gain (loss) on risk management contracts	12	6,513	(407)	9,250	(10,000)
		35,755	36,584	78,308	78,100
Expenses					
Production		9,792	10,681	21,051	21,543
Transportation		11,982	10,808	22,816	21,014
General and administrative		1,570	1,228	3,437	4,079
Share-based compensation	10	428	564	904	1,160
Depletion and depreciation	4, 7	11,853	9,954	23,858	19,700
Exploration and evaluation costs expensed	3	-	1,119	450	1,119
Accretion	8	81	123	186	252
Interest and finance costs		1,519	1,315	3,165	2,433
Unrealized (gain) loss on risk management contracts	12	13,824	(9,625)	3,347	(4,817)
Unrealized revaluation loss on investment		69	4	87	17
		51,118	26,171	79,301	66,500
Net income (loss) and comprehensive income (loss)		(15,363)	10,413	(993)	11,600
Deferred income tax expense (recovery)		(3,698)	2,549	160	3,129
Net income (loss) and comprehensive income (loss)		\$ (11,665)	\$ 7,864	\$ (1,153)	\$ 8,471
Net income (loss) per share	11				
- Basic and diluted		\$ (0.10)	\$ 0.06	\$ (0.01)	\$ 0.07

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian \$000s) (unaudited)			Six Months to June 30, 2020		
	Notes	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, beginning of period		\$ 391,444	\$ 17,605	\$ 12,659	\$ 421,708
Net income (loss) for the period		-	-	(1,153)	(1,153)
Share-based compensation	10	-	904	-	904
Balance, end of period		\$ 391,444	\$ 18,509	\$ 11,506	\$ 421,459

(Canadian \$000s) (unaudited)			Six Months to June 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		-	-	8,471	8,471
Share-based compensation	10	-	1,160	-	1,160
Balance, end of period		\$ 391,444	\$ 16,301	\$ 9,817	\$ 417,562

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

		Three Months Ended June 30		Six Months Ended June 30	
(Canadian \$000s) (unaudited)	Notes	2020	2019	2020	2019
Operating activities					
Net income (loss) for the period		\$ (11,665)	\$ 7,864	\$ (1,153)	\$ 8,471
Non-cash items:					
Unrealized (gain) loss on risk management	12	13,824	(9,625)	3,347	(4,817)
Depletion, depreciation and accretion	4, 7, 8	11,934	10,077	24,044	19,952
Share-based compensation	10	428	564	904	1,160
Lease interest	7	33	38	67	76
Exploration and evaluation costs expensed	3	-	1,119	450	1,119
Unrealized revaluation loss on investment		69	4	87	17
Deferred income tax expense (recovery)		(3,698)	2,549	160	3,129
Decommissioning expenditures	8	(21)	-	(113)	-
Funds flow		10,904	12,590	27,793	29,107
Net change in non-cash working capital items	13	2,636	6,960	2,164	12,904
		13,540	19,550	29,957	42,011
Financing activities					
Payment of lease liability	7	(126)	(124)	(253)	(249)
Increase (decrease) in bank indebtedness		4,534	(5,034)	7,750	(2,204)
		4,408	(5,158)	7,497	(2,453)
Investing activities					
Additions to property and equipment	4	(2,293)	(22,193)	(28,535)	(38,554)
Additions to exploration and evaluation assets	3	(101)	(952)	(334)	(1,535)
Net change in non-cash working capital items	13	(15,554)	8,753	(8,585)	531
		(17,948)	(14,392)	(37,454)	(39,558)
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 June 30, 2020 and December 31, 2019 and for the three and six months ended June 30, 2020 and 2019

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, 2019. All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on August 12, 2020.

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 12.

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, 2019.

In March 2020, the World Health Organization declared the COVID-19 outbreak a global pandemic. The rapid outbreak and subsequent measures intended to limit the spread of COVID-19 have contributed to a significant increase in economic uncertainty, with more volatile commodity prices, currency exchange rates and interest rates. The duration and severity of the business disruptions and reduction in consumer activity internationally and the resulting financial effect is difficult to reliably estimate. The results of the economic downturn and any potential resulting direct or indirect

effect on the Company has been considered in management's estimates at period end. However, there could be further prospective material effects in future periods.

3. EXPLORATION AND EVALUATION

	Six Months Ended June 30, 2020	Year ended December 31, 2019
Balance, beginning of period	\$ 99,737	\$ 102,277
Additions	334	2,169
Dispositions	-	(1,083)
Expiries - exploration and evaluation costs expensed	(450)	(1,140)
Future decommissioning costs	9	178
Transfer to property and equipment	-	(2,664)
Balance, end of period	\$ 99,630	\$ 99,737

As at June 30, 2020, the Company reviewed the carrying amounts of exploration and evaluation assets for indicators of potential impairment. As a result of this assessment, no indicators of impairment were identified.

4. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2020	Year ended December 31, 2019
Cost		
Balance, beginning of period	\$ 746,515	\$ 646,983
Additions	28,535	95,757
Future decommissioning costs	2,192	1,111
Transfer from exploration and evaluation assets	-	2,664
Balance, end of period	\$ 777,242	\$ 746,515
Accumulated depletion and depreciation		
Balance, beginning of period	\$ (256,251)	\$ (216,182)
Depletion and depreciation	(23,640)	(40,069)
Balance, end of period	\$ (279,891)	\$ (256,251)
Net book value, beginning of period	\$ 490,264	\$ 430,801
Net book value, end of period	\$ 497,351	\$ 490,264

As at June 30, 2020, the Company evaluated property and equipment for indicators of potential impairment. Given the ongoing changes in the overall business environment and current uncertainties in commodity markets, at June 30, 2020 the Company reviewed externally available forward commodity prices and as a result of this assessment, no indicators of impairment were identified on property and equipment.

As at December 31, 2019, the balance of assets under construction not subject to depreciation or depletion was \$65.0 million and related to the construction of the Nig Creek Gas Plant located in northeast British Columbia. In February 2020, construction of the Nig Creek Gas Plant was completed and the gas plant is being depreciated on a straight-line basis over its estimated useful life of 35 years.

5. BANK INDEBTEDNESS

As at June 30, 2020, the Company had an extendible revolving credit facility in the amount of \$190 million (December 31, 2019 - \$205 million) based on a bank determined borrowing base related to the Company's producing reserves. Although the borrowing base was set at \$205 million, the Company voluntarily reduced the credit facility amount to \$190 million in order to reduce the associated fees. The credit facility is available to the Company until May 28, 2021, 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 June 30, 2020, debt including outstanding letters of credit amounted to \$142.7 million, representing approximately 75% of the available credit facility.

As at June 30, 2020, the Company had issued letters of credit in the amount of \$13.3 million (December 31, 2019 - \$10.0 million) in support of future natural gas transportation and processing obligations.

6. REVENUE FROM PRODUCT SALES

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

	Three Months Ended June 30, 2020	Three Months Ended June 30, 2019	Six Months Ended June 30, 2020	Six Months Ended June 30, 2019
Natural gas	\$ 23,335	\$ 23,396	\$ 50,185	\$ 62,400
Condensate	5,437	13,468	19,915	25,890
NGL	1,419	704	2,014	5,044
Total	\$ 30,191	\$ 37,568	\$ 72,114	\$ 93,334

Storm's revenue was generated mostly in British Columbia where production was sold primarily to three major energy customers with investment grade credit ratings which accounted for 90% and 95% of the Company's total revenue from product sales for the three and six months ended June 30, 2020, respectively (June 30, 2019 - 80% and 81%, respectively, from two major customers). 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 six months ended June 30, 2020, 53% received Chicago pricing, 18% received BC Station 2 pricing, 12% received AECO pricing, 11% received Sumas pricing, and the remaining 6% received ATP pricing.

7. 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 pertaining to the Company's corporate office lease in Calgary:

	Six Months Ended June 30, 2020	Year Ended December 31, 2019
Cost		
Balance, beginning of period	\$ 3,094	\$ 3,094
Additions	-	-
Balance, end of period	\$ 3,094	\$ 3,094
Accumulated depreciation		
Balance, beginning of period	\$ (437)	\$ -
Depreciation	(218)	(437)
Balance, end of period	\$ (655)	\$ (437)
Net book value, beginning of period	\$ 2,657	\$ 3,094
Net book value, end of period	\$ 2,439	\$ 2,657

As at June 30, 2020, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is \$2.4 million (December 31, 2019 - \$2.7 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 pertaining to the Company's corporate office lease in Calgary:

	Six Months Ended June 30, 2020	Year Ended December 31, 2019
Balance, beginning of period	\$ 2,741	\$ 3,094
Lease payments	(253)	(500)
Lease interest	67	147
Balance, end of period	\$ 2,555	\$ 2,741
Less current portion	509	507
Long-term portion	\$ 2,046	\$ 2,234

As at June 30, 2020, the total undiscounted amount of the estimated future cash flows to settle the Company's lease liability over the remaining lease term is \$2.9 million.

Short-term leases are leases with a lease term of twelve months or less. During the six months ended June 30, 2020, short-term lease costs of approximately \$0.5 million (June 30, 2019 - \$1.7 million) were incurred primarily relating to the lease of drilling equipment which was captured within property and equipment costs.

8. 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 inflated and undiscounted liability required to settle the Company's decommissioning obligation is approximately \$35.4 million (December 31, 2019 - \$38.3 million), with the majority of payments being made in the years 2034 to 2054. A risk-free discount rate of 1.0% (December 31, 2019 - 1.7%) and an inflation rate of 1.0% (December 31, 2019 - 1.4%) was used to calculate the present value of the decommissioning obligation, amounting to \$30.4 million at June 30, 2020.

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

	Six Months Ended June 30, 2020	Year Ended December 31, 2019
Balance, beginning of period	\$ 28,115	\$ 26,334
Obligations incurred	127	2,706
Obligations settled	(113)	(246)
Change in estimates ⁽¹⁾	2,074	(1,171)
Accretion expense	186	492
Balance, end of period	\$ 30,389	\$ 28,115
Less current portion	1,144	448
Long-term portion	\$ 29,245	\$ 27,667

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

9. SHARE CAPITAL

Authorized

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

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

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2019 and June 30, 2020	121,557	\$ 391,444

For the period from January 1, 2020 to August 12, 2020 there were no common shares issued upon the exercise of stock options.

10. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers 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 June 30, 2020, a total of 12,155,681 common shares were available for issuance. At June 30, 2020 and at August 12, 2020, the date of this report, options in respect of 10,277,100 common shares were issued and outstanding and options in respect of 1,878,581 common shares were available for future issue.

Details of the options outstanding at June 30, 2020 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2019	10,188	\$ 2.74
Granted during the period	238	\$ 1.29
Forfeited during the period	(149)	\$ 2.46
Outstanding at June 30, 2020	10,277	\$ 2.72
Number exercisable at June 30, 2020	4,659	\$ 3.83

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
\$1.11 - \$2.85	5,632	3.0	\$ 1.63	852	\$ 1.83
\$2.86 - \$4.50	2,631	1.5	\$ 2.98	1,793	\$ 3.03
\$4.51 - \$5.50	2,014	0.4	\$ 5.39	2,014	\$ 5.39
Total	10,277	2.1	\$ 2.72	4,659	\$ 3.83

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

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the six months ended June 30, 2020 of \$0.46 per share include the following:

	2020
Share price	\$1.29
Exercise price	\$1.29
Volatility	48%
Forfeiture rate	2%
Expected option life (years)	3.7
Risk-free interest rate	0.4%

Share-based compensation expense of \$0.4 million and \$0.9 million was charged to the consolidated statement of income (loss) during the three and six months to June 30, 2020, respectively (2019 - \$0.6 million and \$1.2 million, respectively) with an equivalent offset to contributed surplus.

11. NET INCOME (LOSS) PER SHARE

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

	Three Months ended June 30, 2020	Three Months ended June 30, 2019	Six Months ended June 30, 2020	Six Months ended June 30, 2019
Net income (loss) for the period	\$ (11,665)	\$ 7,864	\$ (1,153)	\$ 8,471
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	\$ (0.10)	\$ 0.06	\$ (0.01)	\$ 0.07

(1) For the three and six months ended June 30, 2020, the Company incurred net losses and therefore there were no dilutive effects of stock options. For the three and six months ended June 30, 2019, 9.1 million weighted average common shares related to stock options were anti-dilutive.

12. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, prepaids and 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 six months ended June 30, 2020.

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 June 30, 2020:

	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	\$ 7,829	\$ (7,829)	\$ -
Long-term asset	1,222	(1,222)	-
Current liability	(10,383)	7,829	(2,554)
Long-term liability	(3,848)	1,222	(2,626)
Net position	\$ (5,180)	\$ -	\$ (5,180)

The following is a summary of the Company's financial assets and financial liabilities that were subject to offset as at December 31, 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	\$ 1,805	\$ (692)	\$ 1,113
Long-term asset	-	-	-
Current liability	(2,734)	692	(2,042)
Long-term liability	(904)	-	(904)
Net position	\$ (1,833)	\$ -	\$ (1,833)

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 June 30, 2020, the Company's three major energy customers with investment grade credit ratings accounted for \$9.5 million of total receivables (June 30, 2019 - \$8.1 million from two major customers) and 90% and 95% of total revenues for the three and six months ended June 30, 2020, respectively (three and six months ended June 30, 2019 - 80% and 81%, 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 June 30, 2020, 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 June 30, 2020.

The maximum exposure to credit risk at June 30, 2020 was the carrying amount of accounts receivable of \$10.8 million. No receivables were impaired at June 30, 2020.

Commodity Price Risk

The Company uses risk management contracts to manage its exposure to fluctuations in commodity prices, by fixing prices of future deliveries of crude oil and natural gas and thus providing stability of funds flow. Although the Company had no crude oil production at June 30, 2020, part of its condensate and NGL stream is sold at a price based on crude oil. Accordingly, a financial investment based on crude oil is used as a proxy for the Company's condensate and NGL stream. At the date of this report, the Company had entered into the following outstanding financial risk management contracts in place to manage commodity price risk:

As at August 12, 2020	Daily Volume	Period Hedged	Average Price (Cdn\$)
Natural Gas Swaps			
NYMEX (US\$)	2,000 Mmbtu	Jul 1, 2020 – Oct 31, 2020	US\$2.42/Mmbtu
NYMEX (US\$)	4,500 Mmbtu	Nov 1, 2020 – Dec 31, 2020	US\$2.49/Mmbtu
NYMEX (US\$)	2,500 Mmbtu	Jan 1, 2021 – Oct 31, 2021	US\$2.32/Mmbtu
NYMEX	2,500 Mmbtu	Jul 1, 2020 – Oct 31, 2020	\$2.86/Mmbtu
NYMEX	2,500 Mmbtu	Jan 1, 2021 – Mar 31, 2021	\$3.69/Mmbtu
NYMEX	10,000 Mmbtu	Apr 1, 2021 – Oct 31, 2021	\$3.32/Mmbtu
NYMEX	2,000 Mmbtu	Nov 1, 2021 – Dec 31, 2021	\$3.55/Mmbtu
Chicago	1,500 Mmbtu	Jul 1, 2020 – Oct 31, 2020	\$3.29/Mmbtu
Chicago	6,000 Mmbtu	Nov 1, 2020 – Dec 31, 2020	\$3.55/Mmbtu
Chicago	13,500 Mmbtu	Jan 1, 2021 – Mar 31, 2021	\$3.65/Mmbtu
Chicago	22,000 Mmbtu	Apr 1, 2021 – Oct 31, 2021	\$3.04/Mmbtu
Chicago	6,000 Mmbtu	Nov 1, 2021 – Dec 31, 2021	\$3.53/Mmbtu
Chicago	4,500 Mmbtu	Nov 1, 2021 – Mar 31, 2022	\$3.65/Mmbtu
Sumas	4,500 Mmbtu	Jul 1, 2020 – Oct 31, 2020	\$3.08/Mmbtu
AECO	10,500 GJ	Jul 1, 2020 – Oct 31, 2020	\$1.72/GJ
AECO	5,000 GJ	Nov 1, 2020 – Mar 31, 2021	\$2.25/GJ
AECO	11,000 GJ	Apr 1, 2021 – Oct 31, 2021	\$2.14/GJ
BC Station 2	5,000 GJ	Jul 1, 2020 – Oct 31, 2020	\$1.57/GJ
BC Station 2	3,000 GJ	Jul 1, 2020 – Aug 31, 2020	\$1.65/GJ
BC Station 2	18,000 GJ	Nov 1, 2020 – Mar 31, 2021	\$2.05/GJ
BC Station 2	25,000 GJ	Apr 1, 2021 – Oct 31, 2021	\$1.87/GJ

As at August 12, 2020	Daily Volume	Period Hedged	Average Price (Cdn\$)
Natural Gas Swaps (continued)			
BC Station 2	15,500 GJ	Nov 1, 2021 – Mar 31, 2022	\$2.31/GJ
BC Station 2	3,000 GJ	Apr 1, 2022 – Oct 31, 2022	\$1.90/GJ
Natural Gas Collars			
NYMEX (US\$)	13,000 Mmbtu	Jul 1, 2020 – Oct 31, 2020	US\$1.92 - \$2.41/Mmbtu
NYMEX (US\$)	8,000 Mmbtu	Nov 1, 2020 – Dec 31, 2020	US\$1.96 - \$2.49/Mmbtu
NYMEX (US\$)	3,000 Mmbtu	Jan 1, 2021 – Mar 31, 2021	US\$2.40 - \$2.75/Mmbtu
NYMEX	22,500 Mmbtu	Jul 1, 2020 – Sep 30, 2020	\$2.78 - \$3.30/Mmbtu
NYMEX	17,500 Mmbtu	Oct 1, 2020 – Oct 31, 2020	\$2.74 - \$3.31/Mmbtu
NYMEX	19,500 Mmbtu	Nov 1, 2020 – Dec 31, 2020	\$2.81 - \$3.36/Mmbtu
NYMEX	5,000 Mmbtu	Jan 1, 2021 – Mar 31, 2021	\$3.45 - \$4.10/Mmbtu
NYMEX	10,500 Mmbtu	Jan 1, 2021 – Mar 31, 2021	\$3.46 - \$3.96/Mmbtu
NYMEX	2,000 Mmbtu	Nov 1, 2021 – Dec 31, 2021	\$3.60 - \$3.78/Mmbtu
NYMEX	6,000 Mmbtu	Nov 1, 2021 – Mar 31, 2022	\$3.53 - \$4.13/Mmbtu
AECO	9,000 GJ	Nov 1, 2020 – Mar 31, 2021	\$2.02 - \$2.49/GJ
AECO	7,000 GJ	Nov 1, 2020 – Mar 31, 2021	\$1.90 - \$2.58/GJ
Natural Gas Differential Swaps			
NYMEX:Chicago (US\$)	12,500 Mmbtu	Jul 1, 2020 – Dec 31, 2020	NYMEX minus US\$0.274/Mmbtu
NYMEX:Chicago (US\$)	5,000 Mmbtu	Jul 1, 2020 – Oct 31, 2020	NYMEX minus US\$0.315/Mmbtu
NYMEX:Chicago (US\$)	12,500 Mmbtu	Jan 1, 2021 – Dec 31, 2021	NYMEX minus US\$0.256/Mmbtu
NYMEX:Chicago	22,500 Mmbtu	Jul 1, 2020 – Sep 30, 2020	NYMEX minus \$0.30/Mmbtu
NYMEX:Chicago	17,500 Mmbtu	Oct 1, 2020 – Oct 31, 2020	NYMEX minus \$0.31/Mmbtu
NYMEX:Chicago	19,500 Mmbtu	Nov 1, 2020 – Dec 31, 2020	NYMEX minus \$0.28/Mmbtu
NYMEX:Chicago	10,500 Mmbtu	Jan 1, 2021 – Mar 31, 2021	NYMEX plus \$0.048/Mmbtu
NYMEX:Chicago	6,000 Mmbtu	Nov 1, 2021 – Mar 31, 2022	NYMEX plus \$0.073/Mmbtu
AECO:BC Station 2	7,000 GJ	Nov 1, 2020 – Mar 31, 2021	AECO minus \$0.10/GJ
Crude Oil Swaps			
WTI	950 Bbls	Jul 1, 2020 – Dec 31, 2020	\$59.56/Bbl
WTI	850 Bbls	Jan 1, 2021 – Jun 30, 2021	\$52.01/Bbl
WTI	400 Bbls	Jul 1, 2021 – Dec 31, 2021	\$53.98/Bbl
Crude Oil Collars			
WTI	800 Bbls	Jul 1, 2020 – Dec 31, 2020	\$57.81 - \$67.08/Bbl
WTI	900 Bbls	Jan 1, 2021 – Jun 30, 2021	\$50.78 - \$59.83/Bbl
WTI	400 Bbls	Jul 1, 2021 – Dec 31, 2021	\$50.00 - \$60.15/Bbl
Crude Oil Differential Swaps			
WTI:C5	800 Bbls	Jul 1, 2020 – Aug 31, 2020	WTI minus \$7.58/Bbl
WTI:C5	1,100 Bbls	Sep 1, 2020 – Dec 31, 2020	WTI minus \$6.67/Bbl
WTI:C5	1,100 Bbls	Jan 1, 2021 – Jun 30, 2021	WTI minus \$4.06/Bbl
Propane Swaps			
Conway	200 Bbls	Jul 1, 2020 – Dec 31, 2020	\$28.25/Bbl
Conway	100 Bbls	Jan 1, 2021 – Jun 30, 2021	\$27.30/Bbl

Physical Delivery Sales Contracts

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.

	Daily Volume	Contract Price
Natural Gas		
Jul 2020 – Oct 2020	14,028 Mmbtu at BC Station 2	Sumas less US\$0.69/Mmbtu
Jul 2020 – Oct 2020	6,000 GJ at BC Station 2	AECO 7A less Cdn\$0.295/GJ
Nov 2020 – Oct 2021	5,000 GJ at BC Station 2	AECO 7A less Cdn\$0.125/GJ
Jul 2020 – Mar 2021	6,000 GJ at ATP	AECO 5A plus Cdn\$0.09/GJ

Interest Rate Risk

The Company may enter into interest rate swap contracts 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. As at June 30, 2020, the Company had the following outstanding financial risk management contracts in place to manage interest rate risk:

Index	Effective Date	Notional Principal	Remaining Term	Fixed Contract Rate
One-month bankers' acceptance - CDOR ⁽¹⁾	May 2019	\$25 million	Jul 2020 – May 2022	1.949%
One-month bankers' acceptance - CDOR ⁽¹⁾	Jan 2020	\$10 million	Jul 2020 – Jan 2023	1.943%
One-month bankers' acceptance - CDOR ⁽¹⁾	Jan 2020	\$15 million	Jul 2020 – Jan 2021	1.985%

(1) Canadian Dollar Offered Rate.

Risk Management

Risk management contracts may be used by the Company to manage exposure to market risks related to commodity prices, exchange rates and interest rates. The use of financial risk management contracts is governed by Storm's Board of Directors and follows guidelines and limits approved by the Board. Storm does not use derivative contracts for speculative purposes. All derivative contracts are classified 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.

The fair market value of these risk management contracts at June 30, 2020 was a net liability position of \$5.2 million (December 31, 2019 - net liability position of \$1.8 million) and is included on the balance sheet as either a risk management asset or liability and is classified as current or non-current based on the contractual terms specific to the instruments. For the three and six months ended June 30, 2020, this resulted in unrealized mark-to-market losses of \$13.8 million and \$3.3 million, respectively, (June 30, 2019 - unrealized mark-to-market gains of \$9.6 million and \$4.8 million, respectively) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

The Company realized gains from risk management price contracts in place in the amount of \$6.5 million and \$9.3 million, respectively, for the three and six months ended June 30, 2020 (June 30, 2019 - realized losses of \$0.4 million and \$10.0 million, respectively).

Sensitivities

The following table summarizes the effects of movement in commodity prices and interest rates on net income (loss) due to changes in the fair value of risk management contracts in place at June 30, 2020. 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	Six Months Ended June 30, 2020	
	Gain/(Loss)	
Increase of US\$10.00/Bbl in the price of WTI ⁽¹⁾	\$	(6,999)
Decrease of US\$10.00/Bbl in the price of WTI ⁽¹⁾	\$	6,999
Increase of US\$0.10/Mmbtu in the price of NYMEX natural gas	\$	(4,072)
Decrease of US\$0.10/Mmbtu in the price of NYMEX natural gas	\$	4,072
Increase of 100 basis points (1%) in interest rates	\$	827
Decrease of 100 basis points (1%) in interest rates	\$	(827)

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

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months ended June 30, 2020	Three Months ended June 30, 2019	Six Months ended June 30, 2020	Six Months ended June 30, 2019
Accounts receivable	\$ 9,637	\$ 12,235	\$ 11,086	\$ 18,263
Prepays and deposits	(73)	201	130	466
Accounts payable and accrued liabilities	(22,482)	3,277	(17,637)	(5,294)
Change in non-cash working capital	\$ (12,918)	\$ 15,713	\$ (6,421)	\$ 13,435
Relating to:				
Operating activities	\$ 2,636	\$ 6,960	\$ 2,164	\$ 12,904
Investing activities	(15,554)	8,753	(8,585)	531
Change in non-cash working capital	\$ (12,918)	\$ 15,713	\$ (6,421)	\$ 13,435
Interest paid during the period	\$ 1,566	\$ 1,268	\$ 3,135	\$ 2,305
Income taxes paid during the period	\$ -	\$ -	\$ -	\$ -

14. COMMITMENTS

At June 30, 2020, the Company has the following long-term commitments over the next five years and thereafter:

	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and processing commitments	\$ 31,967	\$ 63,024	\$ 50,677	\$ 27,567	\$ 27,702	\$ 208,397	\$ 409,334
Office lease ⁽¹⁾	178	356	356	356	356	385	1,987
Total	\$ 32,145	\$ 63,380	\$ 51,033	\$ 27,923	\$ 28,058	\$ 208,782	\$ 411,321

(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 Wierzbowski ⁽²⁾⁽³⁾

James K. Wilson ⁽¹⁾

(1) Member, Audit Committee (2) Member, Reserves, Environment, Health and Safety 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

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Abbreviations

ATP	Alliance Transfer Point	Mbbl	Thousands of barrels
Bbls	Barrels of oil or natural gas liquids	Mboe	Thousands of barrels of oil equivalent
Bbls/d	Barrels per day	Mcf	Thousands of cubic feet
Bcf	Billions of cubic feet	Mcf/d	Thousands of cubic feet per day
Boe	Barrels of oil equivalent	Mmbtu	Millions of British Thermal Units
Boe/d	Barrels of oil equivalent per day	Mmbtu/d	Millions of British Thermal Units per day
Bopd	Barrels of oil per day	Mmcf	Millions of cubic feet
Btu	British thermal unit	Mmcf/d	Millions of cubic feet per day
Cdn\$	Canadian dollar	NGL	Natural gas liquids
CGU	Cash generating unit	OPEC	Organization of Petroleum Exporting Countries
DPIIP	Discovered Petroleum Initially in Place	PDP	Proved developed producing (reserves)
GJ	Gigajoules	TSX	Toronto Stock Exchange
GJ/d	Gigajoules per day	US	United States
kPa	Kilopascal	US\$	United States dollar
		WTI	West Texas Intermediate



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