2020 QUARTER 3 REPORT

STORM RESOURCES

Q3

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
FINANCIAL				
Revenue from product sales(1)	30,010	31,417	102,124	124,751
Funds flow	6,681	11,973	34,474	41,080
Per share – basic and diluted ($)	0.05	0.10	0.28	0.34
Net income (loss)	(16,934)	(64)	(18,087)	8,407
Per share – basic and diluted ($)	(0.14)	(0.00)	(0.15)	0.07
Cash return on capital employed (“CROCE”)(2)	11%	15%	11%	15%
Return on capital employed (“ROCE”)(2)(4)	(2%)	9%	(2%)	9%
Capital expenditures	14,219	32,841	43,088	72,930
Debt including working capital deficiency(2)(3)	137,983	123,342	137,983	123,342
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,557	121,557
Outstanding end of period – basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	17.14	18.36	16.72	23.50
Transportation costs	(6.43)	(5.83)	(5.58)	(5.84)
Revenue net of transportation	10.71	12.53	11.14	17.66
Royalties	(0.77)	0.19	(0.72)	(0.92)
Production costs	(4.84)	(5.88)	(4.83)	(5.96)
Field operating netback(2)	5.10	6.84	5.59	10.78
Realized gain (loss) on risk management contracts	0.51	1.64	1.66	(1.35)
General and administrative	(0.72)	(0.79)	(0.77)	(1.02)
Interest and finance costs	(1.08)	(0.69)	(0.81)	(0.67)
Decommissioning expenditures	-	-	(0.02)	-
Funds flow per Boe	3.81	7.00	5.65	7.74
Barrels of oil equivalent per day (6:1)	19,027	18,596	22,291	19,443
Natural gas production				
Thousand cubic feet per day	91,526	91,053	107,361	95,013
Price (Cdn$ per Mcf)(1)	2.47	2.42	2.41	3.19
Condensate production				
Barrels per day	1,637	1,856	2,186	2,044
Price (Cdn$ per barrel)(1)	46.79	63.45	45.01	65.81
NGL production				
Barrels per day	2,136	1,564	2,211	1,563
Price (Cdn$ per barrel)(1)	10.95	2.29	6.87	12.59
Wells drilled (net)	4.0	1.0	5.0	6.0
Wells completed (net)	-	5.0	3.5	5.0
Wells started production (net)	-	-	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 24 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.
(4) Includes a non-cash unrealized loss on risk management contracts of $21.4 million for the nine months ended September 30, 2020.

PRESIDENT’S MESSAGE

2020 THIRD QUARTER HIGHLIGHTS

Production, pricing and funds flow for the quarter were reduced by planned turnarounds at two third-party gas plants and a pipeline outage which reduced natural gas sales into higher priced Canadian markets. Cost structure continues to improve with lower production costs being realized following start-up of the Nig Creek Gas Plant in February 2020 while record low drilling and completion costs were realized for the four wells at Nig Creek. To date, the COVID-19 pandemic has had no direct impact on Storm’s operations.

- Production was 19,027 Boe per day, a decrease of 20% from the previous quarter and an increase of 2% year over year. This was consistent with guidance of 19,000 to 21,000 Boe per day. Approximately 40% of corporate production was shut in during September for planned turnarounds at third-party gas plants.

- Liquids production (condensate plus NGL) totaled 3,773 barrels per day and represented 20% of total production and 31% of total revenue. NGL production increased 37% from last year as a result of higher recoveries that are realized at the Nig Creek Gas Plant.

- Capacity of the 100% working interest Nig Creek Gas Plant is now estimated to be 60 to 70 Mmcf raw per day based on throughput in September when several wells were redirected from Umbach during the third-party gas plant turnarounds. Design capacity was 50 Mmcf raw per day.

- Nig Creek area sales averaged 7,845 Boe per day (41% of corporate production) at a production cost of $1.21 per Boe. Well productivity continues to meet or exceed expectations and results from the first well in the lower Montney (840 Boe per day sales with 33% liquids over the first 9 months) indicate that there is a second layer to develop. Four new wells (4.0 net) were recently drilled and completed and started producing in late October.

- Drilling and completion costs for the four most recent wells at Nig Creek averaged $4.1 million based on field estimates which is a reduction of approximately 25% from last year’s average cost.

- Revenue net of transportation was $10.71 per Boe, a 15% decline from last year mainly due to a lower condensate price and an increase in the transportation cost per Boe due to the third-party gas plant turnarounds which resulted in approximately $1.0 million of unused firm transportation. The realized natural gas price did not reflect the recent improvement in AECO and BC Station 2 prices given that 67% of sales were into the lower priced Chicago market, an increase from previous quarters as a result of an outage in September on Spectra’s T-north Fort St. John lateral to BC Station 2 (coincided with the third-party gas plant turnarounds).

- Production, general and administrative, and interest and finance costs totaled $6.64 per Boe, a reduction of 10% year over year. Production costs per Boe declined 18% as a result of reduced third-party processing fees following start-up of the Nig Creek Gas Plant in February. The reduction would have been larger if not for the third-party gas plant turnarounds which reduced production resulting in approximately $1.2 million of unused firm processing.

- Funds flow was $6.7 million, or $0.05 per share, a reduction from $12.0 million last year. With production largely unchanged, the reduction in production costs per Boe was more than offset by lower revenue net of transportation, an increase in royalties related to the timing of infrastructure royalty credits, and a reduced hedging gain.

- Net loss was $16.9 million with the largest contributor to the loss being an unrealized (non-cash) hedging loss of $18.0 million which represents the change in the value of future hedging contracts from the previous quarter.

- Capital investment was $14.2 million (within guidance of $10 to $15 million) with the majority, or $10.1 million, directed to drilling and starting the completions of four wells at Nig Creek.

- Total debt including working capital deficiency was $138 million. With capital investment in 2020 being approximately equal to funds flow, debt is forecast to be approximately $130 million at year end which will represent 2.2 times forecast annual funds flow.

- Hedges protect revenue on approximately 47% of forecast production for the fourth quarter of 2020 and 40% for 2021. The financial liability for future hedging contracts was $23.2 million, an $18.0 million increase from the previous quarter as a result of the recent improvement in the forward strip for commodity prices.

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 83 horizontal wells (78.4 net) drilled to the end of the third quarter.

Field activity in the third quarter included drilling and starting the completions of four horizontal wells (4.0 net) in the Nig Creek area.

Fourth quarter activity will include finishing the completions and pipeline connections of the four wells at Nig Creek with production starting in late October. At Umbach, the first two or three wells (2.0 or 3.0 net) on a six-well pad will be drilled with completions planned for the first quarter of 2021.

At the end of the third quarter, there were eight Montney horizontal wells (6.5 net) that had not started producing which included four wells (4.0 net) at Nig Creek and three wells (1.5 net) at Fireweed. Completed wells included two (1.0 net) at Fireweed while completions were underway on four wells (4.0 net) at Nig Creek.

At Umbach (average 90% working interest), produced raw natural gas contains 1.2% H_2S with approximately 80% directed to the McMahon Gas Plant and 20% to the Stoddart Gas Plant. Field compression capacity totals 150 Mmcf raw per day while firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon and 15 Mmcf per day at Stoddart). Third quarter volumes averaged 63 Mmcf raw per day and were reduced approximately 17 Mmcf raw per day by planned turnarounds at the McMahon and Stoddart Gas Plants in September. Activity in 2021 is expected to include drilling the remaining three or four wells (3.0 or 4.0 net) on a six-well pad and completing all six wells (6.0 net).

At Nig Creek (100% working interest), produced raw natural gas contains 0.1% H_2S and is directed to the 100% working interest sour gas plant that started up in February 2020. Third quarter throughput averaged 42 Mmcf raw per day, sales were 7,845 Boe per day with liquids at 46 barrels per Mmcf sales, and the production cost was $1.21 per Boe. Estimated capacity of the gas plant has been revised higher to 60 to 70 Mmcf raw per day from design capacity of 50 Mmcf raw per day as a result of H_2S content being lower than forecast. Higher capacity was tested during September with several wells from Umbach being redirected to the gas plant during the third-party gas plant outages. Future drilling is expected to include three to four wells in the mid/upper Montney each year to keep the gas plant full. The first well in the lower Montney has averaged 840 Boe per day sales over the first 9 months (including 200 barrels per day of condensate and 75 barrels per day of NGL) and the timing for further drilling will largely depend on the WTI oil price given that condensate is expected to represent 20% to 25% of the first year sales volume (versus 10% of corporate sales year to date). Activity in 2021 is expected to include adding a low pressure inlet with compression at the gas plant to increase rates from existing wells plus drilling and completing three wells (3.0 net) in the upper/mid Montney in the third quarter of 2021.

At Fireweed (50% working interest), activity was previously deferred by up to one year following the collapse in the WTI crude oil price in April 2020. 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 and Nig Creek. There are currently three standing wells (1.5 net) with two completed wells (1.0 net). In the third quarter of 2020, construction of an access road was restarted in anticipation of advancing development in 2021. Activity levels for 2021 are expected to be finalized before year end with preliminary plans including four drills (2.0 net), two completions (1.0 net), and constructing a 50 Mmcf raw per day field compression facility with associated pipelines (50% working interest). First production from the area could be realized as early as the fourth quarter of 2021.

HEDGING

The objective of the commodity price hedging program is to support longer-term growth by protecting revenue on up to 50% of current production for the next 18 months and up to 25% for 19 to 36 months forward. The current hedge position is shown below (excludes price differential contracts which are shown in the financial statements) with hedges for 2021 protecting approximately 40% of forecast production. Future production growth is not hedged and will receive actual pricing.

	Q4/20	2021
Natural Gas Hedges		
% Forecast Nat Gas Production	50%	45%
Collars	33,000 Mcf/d(1) Floor Cdn$2.99 per Mcf(2) Ceiling Cdn$3.68 per Mcf(2)	9,000 Mcf/d(1) Floor Cdn$3.48 per Mcf(2) Ceiling Cdn$4.15 per Mcf(2)
Fixed Price	28,000 Mcf/d(1) Cdn$2.90 per Mcf(2)	48,700 Mcf/d(1) Cdn$3.16 per Mcf(2)
Liquids Hedges		
% Forecast Liquids Production	37%	25%
Collars	800 Bpd Floor WTI Cdn$57.81 per barrel Ceiling WTI Cdn$67.60 per barrel	650 Bpd Floor WTI Cdn$50.54 per barrel Ceiling WTI Cdn$59.93 per barrel
Fixed Price	950 Bpd WTI Cdn$59.75 per barrel 200 Bpd Propane Conway Cdn$28.25 per barrel	750 Bpd WTI Cdn$53.02 per barrel 50 Bpd Propane Conway Cdn$27.30 per barrel

(1) Using corporate average heat content 1.23 GJ per Mcf and 1.17 Mmbtu per Mcf.
(2) Hedges in US$ are converted using an exchange rate of Cdn$1.34 per US$1.

OUTLOOK

Production in the fourth quarter of 2020 is forecast to average 25,000 to 27,000 Boe per day with capital investment of approximately $15 million to finish the completion of a four-well (4.0 net) pad at Nig Creek and to drill two or three wells (2.0 or 3.0 net) at Umbach on a six-well pad.

Updated guidance for 2020 is provided below. Capital investment is expected 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

	Current August 13, 2020	Current November 10, 2020
Cdn$/US$ exchange rate	0.74	0.75
Chicago daily natural gas - US$/Mmbtu	$1.85	$1.90
AECO daily natural gas - Cdn$/GJ	$2.00	$2.15

2020 Guidance

	Current August 13, 2020	Current November 10, 2020
BC Station 2 daily natural gas - Cdn$/GJ	$1.95	$2.15
WTI - US$/Bbl	$38.50	$38.50
Edmonton condensate diff - US$/Bbl	($3.50)	($2.25)
Est revenue net of transport (excl hedges) - $/Boe	$12.00 - $12.50	$12.75 - $13.00
Est production costs - $/Boe	$4.50 - $4.75	$4.50 - $4.75
Est royalty rate (% revenue net transportation)	5% - 6%	7%
Est mid-point field operating netback - $/Boe(1)	$6.70	$7.35
Est realized hedging gains or (losses) - $ million	$10.0 - $11.0	$6.5 - $7.5
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $6.5
Est interest expense - $ million	$7.0 - $8.0	$7.0 - $7.5
Est capital investment (excluding A&D) - $ million	$52.0 - $60.0 (Nig Crk GP $12.0 million)	$58.0 (Nig Crk GP $12.0 million)
Forecast fourth quarter Boe/d Forecast fourth quarter liquids Bbls/d	25,000 - 28,000 5,100 - 5,600	25,000 - 27,000 5,100 - 5,500
Forecast annual Boe/d Forecast annual liquids Bbls/d	22,500 - 24,000 4,300 - 4,800	23,000 - 23,500 4,600 - 4,700
Est annual funds flow - $ million(2)	$53.0 - $57.0(2)	$55.0 - $57.0
Horizontal wells drilled - gross Horizontal wells completed - gross Horizontal wells starting production - gross	6 - 9 (5.0 - 8.0 net) 8 (7.5 net) 7 (7.0 net)	8 (7.0 net) 8 (7.5 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-points for the estimated field operating netback, estimated cash G&A, estimated hedging gain or loss and estimated interest expense.

2020 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
Nov 10, 2020	$1.90	$2.15	$38.50	$58.0	$55.0 - $57.0	23,000 - 23,500

Initial guidance for 2021 is provided below. Capital investment is intended to be less than forecast funds flow. Comparing to the current forward strip, Storm's forecast pricing is approximately 5% lower for the WTI oil price and for natural gas pricing.

2021 Guidance

	Initial November 10, 2020
Cdn$/US$ exchange rate	0.76
Chicago daily natural gas - US$/Mmbtu	$2.65
AECO daily natural gas - Cdn$/GJ	$2.50
BC Station 2 daily natural gas - Cdn$/GJ	$2.50
WTI - US$/Bbl	$40.00
Edmonton condensate diff - US$/Bbl	($3.00)
Est revenue net of transport (excl hedges) - $/Boe	$17.00 - $18.00
Est production costs - $/Boe	$4.00 - $4.50
Est royalty rate (% revenue net transportation)	7% - 8%
Est mid-point field operating netback - $/Boe(1)	$11.95
Est realized hedging gains or (losses) - $ million	($8.0 - $10.0)
Est cash G&A - $ million	$6.0 - $7.0
Est interest expense - $ million	$7.0 - $8.0
Est capital investment (excluding A&D) - $ million	$85.0 - $90.0
Forecast fourth quarter Boe/d(2)	30,000 - 32,000
Forecast fourth quarter liquids Bbls/d	6,800 - 7,300
Forecast annual Boe/d	26,000 - 28,000
Forecast annual liquids Bbls/d	5,600 - 6,000
Est annual funds flow - $ million(3)	$90.0 - $99.0
Horizontal well drilled - gross	11 (9.0 net)
Horizontal wells completed - gross	11 (10.0 net)
Horizontal wells starting production - gross	13 (11.0 net)

(1) Based on the mid-point for each of revenue net of transportation, royalty rate and production costs.
(2) Assuming first production from the Fireweed area in October 2021.
(3) Based on the range for forecast annual production and using the mid-points for the estimated field operating netback, estimated cash G&A, estimated hedging gain or loss and estimated interest expense.

Capital investment for 2021 is expected to be allocated as follows:

- up to $35 million at Fireweed to drill four horizontal wells (2.0 net), complete two wells (1.0 net), and to construct a 50 Mmcf raw per day field compression facility with associated pipelines (50% working interest);
- $28 million at Nig Creek which includes $7 million to add a low pressure inlet with compression at the gas plant (100% working interest) and to drill, complete and pipeline connect three horizontal wells (3.0 net); and
- $27 million at Umbach to drill, complete and pipeline connect six horizontal wells (6.0 net).

Development at Fireweed was previously paused for up to one year, however, the recent improvement in the WTI oil price and BC Station 2 natural gas price supports the restart of development. Planned activity levels for 2021 are not expected to be finalized until the end of 2020 with preliminary plans including net capital investment of up to $35 million with first production in October 2021.

Based on forecast production, natural gas sales in 2021 are expected to be 46% at Chicago, 36% at BC Station 2, 11% at AECO and 7% at Alliance ATP. Sales into Canadian markets will increase from approximately 35% in 2020 to 54% in 2021 as a result of the expiry of a sales commitment in October 2020 for 12 Mmcf per day at Sumas and as incremental production growth is directed to BC Station 2. Sales into Chicago use contracted capacity on the Alliance Pipeline which currently totals 57 Mmcf per day with Storm having the option to renew any portion or all of the capacity on an annual basis. Storm's natural gas price for the first nine months of 2020 declined by 25% year over year largely as a result of 67% of sales being into US markets at Chicago and Sumas where prices declined by an average of 40%

(as compared to the average increase of 75% for Canadian prices at AECO and BC Station 2). The 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.

At Nig Creek, results from the first well targeting the lower Montney show that there is a second layer to develop with rates of return expected to be comparable to development at Umbach depending on the WTI oil price. With production having a higher proportion of condensate (average 840 Boe per day sales including 200 barrels per day of condensate over the first 9 months), the timing for follow-up wells is largely dependent on the WTI oil price.

Financial results are expected to improve significantly in the fourth quarter of 2020 and into 2021 with higher forward strip commodity prices, increased natural gas sales into Canadian markets, and with production growth from the Nig Creek area where production costs are materially lower ($1.29 per Boe year to date) than the corporate average and where liquids recoveries are the highest (22% liquids year to date).

As always, capital investment will remain flexible and may be adjusted up or down depending on commodity prices. In 2020, capital investment is expected to be equal to or less than funds flow with forecast annual production increasing by 15% from last year. For 2021, the intent is to improve financial flexibility with capital investment expected to be less than funds flow while forecast annual production increases by a further 18%.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 10, 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.

Forward-Looking Statements - Such statements made in this report are subject to the limitations set out in Storm’s Management’s Discussion and Analysis dated November 10, 2020 for the three and nine months ended September 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 nine months ended September 30, 2020. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 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 November 10, 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 November 10, 2020.

See discussion related to "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 22 to 25.

BASIS OF PRESENTATION

Financial data presented below have been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 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 nine month periods ended September 30, 2019.

OPERATIONAL AND FINANCIAL RESULTS

Overview

A similar theme played out in the third quarter of 2020 compared to the same period in the prior year as third-party outages and low commodity prices reduced Storm's production and funds flow, although the most significant of the three outages in the third quarter of 2020 was a planned event compared to the unplanned outages that affected the prior year. As previously communicated, the McMahon Gas Plant incurred a 28-day planned turnaround in September 2020 and, coupled with a concurrent 8-day turnaround at the Stoddart Gas Plant, reduced September 2020 production to approximately 13,400 Boe per day. Production levels in the third quarter of 2020 were also affected by a 6-day unplanned outage at the McMahon Gas Plant and unplanned outages on the Enbridge T-North system.

Similar to the second quarter of 2020, Storm focused on managing through 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. In looking past the third quarter at significantly higher natural gas prices, a four-well pad at Nig Creek was drilled in the third quarter to capitalize on higher winter pricing with the four wells completed in October and on production in late October. Capital expenditures in the third quarter were consistent with the previously announced guidance range of $10 to $15 million.

While demand for crude oil has improved and WTI prices have stabilized around the US$40.00 per barrel level, the economic situation remains highly volatile with a second wave of COVID-19 well underway across the globe. As previously stated, the extent to which the ongoing presence of COVID-19 may affect the Company remains uncertain; however, depending on the severity and duration of the pandemic, it is possible that COVID-19 may have further adverse effects on commodity prices, the Company's business, results of operations and financial condition. 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.

Subsequent to quarter end, the Company's bank syndicate, upon completion of a mid-year review, confirmed Storm's bank facility at $205 million. 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 third quarter (including $13.4 million for outstanding letters of credit). With funds flow for the remainder of the year expected to exceed capital expenditures, low maintenance capital, a strong hedge portfolio, and approximately $40 million of unused credit capacity, Storm maintains adequate financial liquidity to manage through the ongoing volatility in commodity prices.

Production and Revenue

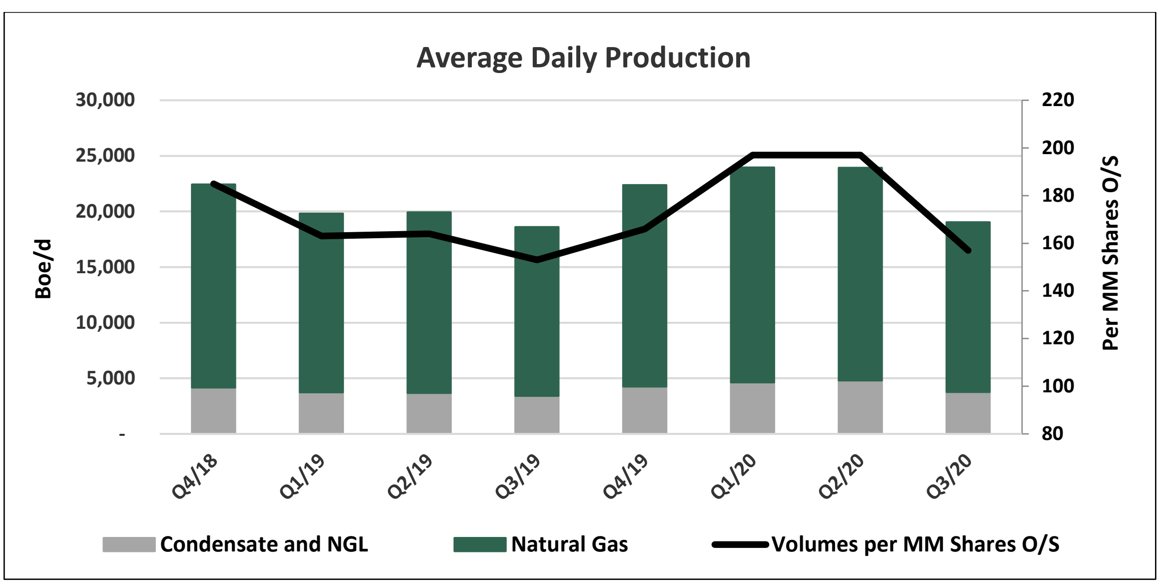
Average Daily Production

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Quarter-Over-Quarter Change	Nine Months to Sept. 30, 2020	Nine months to Sept. 30, 2019	Year-Over-Year Change
Natural gas (Mcf/d)	91,526	91,053	1%	107,361	95,013	13%
Condensate (Bbls/d)	1,637	1,856	(12%)	2,186	2,044	7%
NGL (Bbls/d)	2,136	1,564	37%	2,211	1,563	41%
Total (Boe/d)	19,027	18,596	2%	22,291	19,443	15%
Natural gas weighting	80%	82%		80%	81%	
Condensate weighting	9%	10%		10%	11%	
NGL weighting	11%	8%		10%	8%	

Production for natural gas, condensate and NGL for the third quarter of 2020 was 2% higher than the third quarter of 2019. The third quarter of 2020 was affected by 34 days of third-party outages at the McMahon Gas Plant which reduced production by approximately 3,600 Boe per day. Of the 34 days of outages, 28 days related to planned outages while the remaining six days of outages were unplanned. Comparatively, the third quarter of 2019 was affected by a third-party outage at the McMahon Gas Plant (14 days) in addition to the voluntary curtailment of production in response to the low natural gas price at Station 2.

Production for the first nine months of 2020 was 15% higher than the same period of 2019 primarily due to incremental production from new wells brought on production in late 2019 and in the first half of 2020. Furthermore, the Nig Creek Gas Plant was commissioned in February 2020 leading to incremental production from higher NGL recovery and reduced gas shrinkage.

The Company started production from three new 100% working interest horizontal wells at Umbach during the first nine months of 2020.



Revenue from Product Sales[1]

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Natural gas	$ 20,813	$ 20,252	$ 70,998	$ 82,652
Condensate	7,046	10,836	26,961	36,726
NGL	2,151	329	4,165	5,373
Total	$ 30,010	$ 31,417	$ 102,124	$ 124,751
% of Total Revenue by Product Type				
Natural gas	69%	64%	70%	66%
Condensate and NGL	31%	36%	30%	34%
Total	100%	100%	100%	100%

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

Revenue from product sales for the third quarter of 2020 decreased by 4% when compared to the third quarter of 2019 primarily as a result of a decrease in the Company's realized condensate price and condensate production volumes, partially offset by an increase in the Company's average realized price for NGL. For the nine month periods, revenue from product sales decreased by 18% year over year due to the Company's average realized price decreasing by 29%, partially offset by production volumes increasing by 15%.

Average Selling Prices[1]

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Natural gas – Mcf	$ 2.47	$ 2.42	$ 2.41	$ 3.19
Condensate – Bbl	$ 46.79	$ 63.45	$ 45.01	$ 65.81
NGL – Bbl	$ 10.95	$ 2.29	$ 6.87	$ 12.59
Per Boe	$ 17.14	$ 18.36	$ 16.72	$ 23.50

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

On a per-Boe basis, the Company's average realized price for the three months ended September 30, 2020 decreased compared to the same period of 2019, with the decrease driven by lower condensate pricing, partially offset by higher NGL and natural gas pricing. The decrease in condensate pricing is primarily due to a significant reduction in WTI benchmark pricing. The increase in realized natural gas pricing is primarily due to higher BC Station 2 and AECO index pricing, partially offset by a reduction in benchmark prices at Chicago and Sumas. The Company's NGL price for the third quarter of 2020 was 20% of WTI, within the guidance range of 15% to 20% of WTI.

On a per-Boe basis, the Company's average realized price for the first nine months of 2020 decreased by 29% when compared to the first nine 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 and AECO 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 Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Natural gas				
Chicago monthly index (US$/Mmbtu)	1.87	2.03	1.82	2.60
Chicago daily index (US$/Mmbtu)	1.85	2.10	1.74	2.48
Sumas (US$/Mmbtu)	1.90	2.08	1.94	3.66
AECO monthly index (Cdn$/GJ)	2.04	0.99	1.96	1.32
AECO daily index (Cdn$/GJ)	2.12	0.87	1.98	1.44
BC Station 2 (Cdn$/GJ)	2.14	0.63	1.96	0.81
Crude Oil				
WTI (US$/Bbl)	40.93	56.45	38.32	57.06
WTI (Cdn$/Bbl)	54.50	74.57	51.88	75.84
Edmonton condensate (Cdn$/Bbl)	50.00	68.70	47.90	70.21
Exchange rate (US$/Cdn$)	0.75	0.76	0.74	0.75

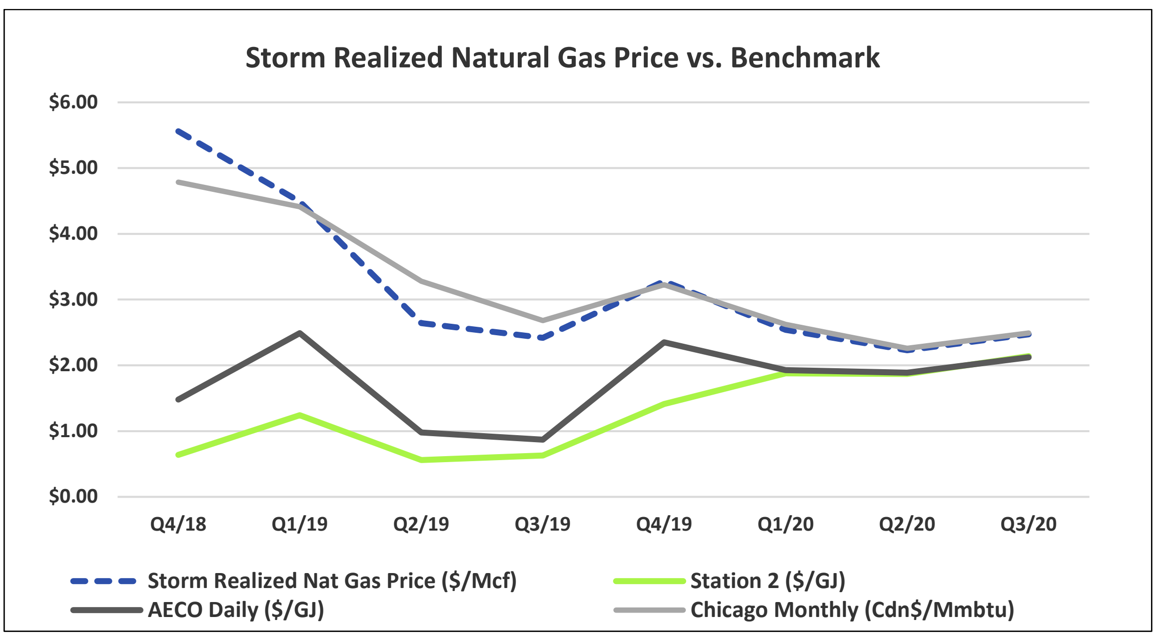
US natural gas prices trended lower in 2019, particularly in the latter half of the year, due to increasing supply and reduced demand through the summer and into shoulder season. US natural gas prices have been under further pressure in 2020 with higher storage levels at the end of last winter's heating season. US natural gas production has decreased since the spring and LNG exports have rebounded since the summer of 2020. As a result, natural gas pricing has gained momentum into the fourth quarter of 2020 and 2021 with the expectation that supply/demand will be much tighter this winter.

BC Station 2 pricing increased in the third quarter of 2020 compared to the third quarter of 2019 due to the higher AECO price with the differential to AECO narrowing significantly with the decline in receipts onto the Enbridge T-north system following completion of the TC Energy North Montney pipeline in January 2020.

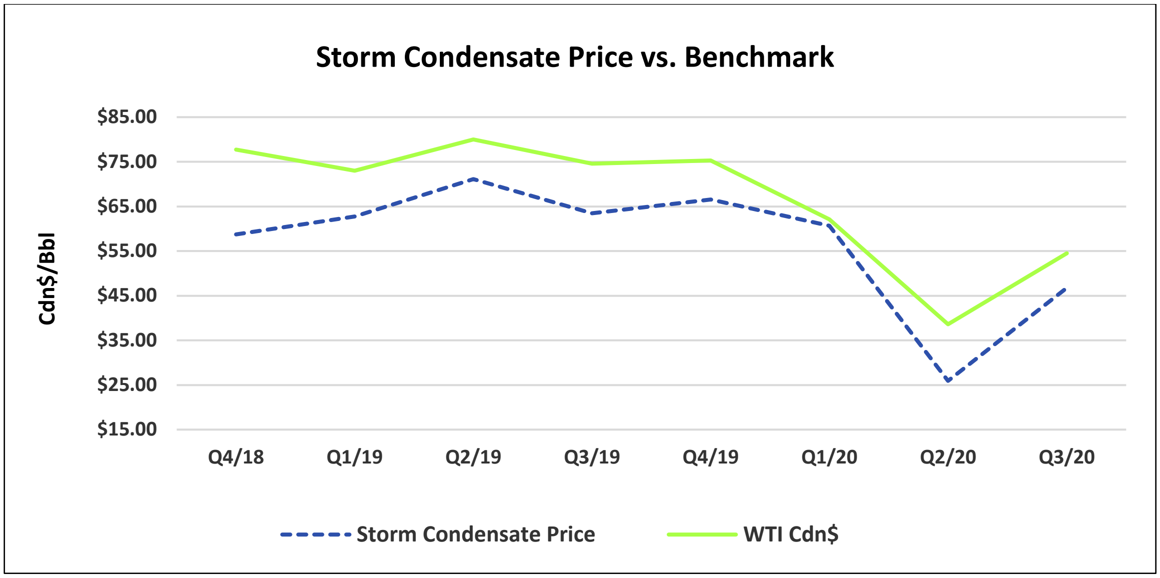
WTI crude oil pricing, the benchmark for mid-continent inland North American crude oil prices at Cushing, Oklahoma, on which a large part of the Company's condensate and NGL revenue is based, declined 27% from US$56.45 per barrel during the third quarter of 2019, to US$40.93 per barrel in the third quarter of 2020. The decline was the result of elevated supply levels and the onset of demand destruction from economic shut-downs associated with COVID-19. Offsetting the decrease in WTI was a narrowing of the condensate differential from a discount of US$4.44 per barrel in the third quarter of 2019 to a discount of US$3.38 per barrel in the third quarter of 2020.

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

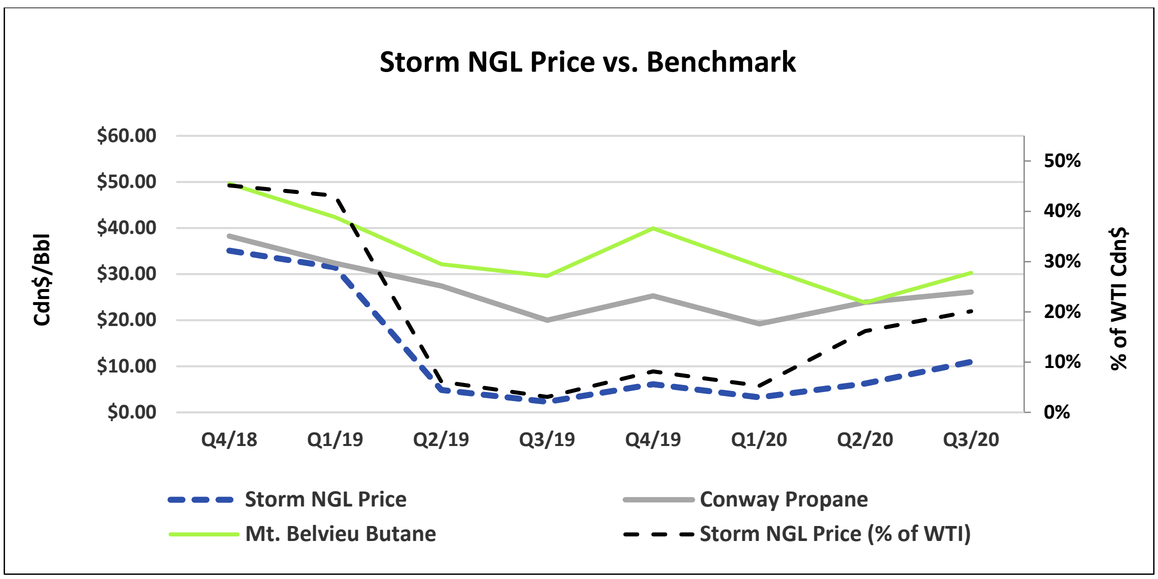
	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Chicago monthly index price	39%	33%	32%	35%
Chicago daily index price	28%	29%	25%	23%
AECO index price	12%	10%	13%	11%
BC Station 2 index price	7%	17%	15%	18%
Sumas index price	10%	11%	10%	11%
Alliance Transfer Point ("ATP")	4%	-	5%	2%
Total	100%	100%	100%	100%



In the third quarter of 2020, Storm's realized natural gas price increased 2% from the third quarter of 2019, as significant increases in Station 2 and AECO pricing were partially offset by lower Chicago and Sumas pricing. The Company's natural gas sales price largely tracks Chicago pricing given that 57% of year-to-date sales are at Chicago.



Storm's realized condensate price of $46.79 per barrel for the third quarter of 2020 decreased by 26% from the third quarter of 2019 primarily as a result of a decrease in the WTI price.



In the third quarter of 2020, Storm's realized price for NGL, excluding condensate, increased relative to the same period of 2019 due to higher contracted prices with marketers and higher propane pricing, partially offset by lower WTI pricing.

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.

Realized Gain (Loss) on Risk Management

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Natural gas	$ 201	$ 1,914	$ 3,584	$ (8,174)
Liquids[(1)]	697	897	6,564	985
Realized gain (loss) on risk management contracts	$ 898	$ 2,811	$ 10,148	$ (7,189)
Per Boe	$ 0.51	$ 1.64	$ 1.66	$ (1.35)

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

Although the Company has no crude oil production, condensate and approximately half 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 consist of the portion of contracts that have settled during the reporting period. The realized gains for the three and nine months ended September 30, 2020 are due to lower WTI crude oil pricing combined with lower natural gas pricing at Chicago and Sumas.

Royalties

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period	$ 1,343	$ (332)	$ 4,399	$ 4,902
Percentage of revenue from product sales	4.5%	(1.1%)	4.3%	3.9%
Per Boe	$ 0.77	$ (0.19)	$ 0.72	$ 0.92

Royalties, as a percentage of revenue from product sales, increased in the third quarter of 2020 compared to the same period in 2019 primarily due to the receipt of infrastructure royalty credits of $1.9 million in 2019.

Royalties, as a percentage of revenue from product sales, increased in the nine months ended September 30, 2020 compared to the same period in 2019 primarily due to the receipt of infrastructure royalty credits of $3.5 million in 2019 versus no credits received to date in 2020. Lower commodity prices reduced the benefit from the BC Deep Well Royalty Program. 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.

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 Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period	$ 8,471	$ 10,068	$ 29,522	$ 31,611
Per Boe	$ 4.84	$ 5.88	$ 4.83	$ 5.96

Total production costs for the third quarter and first nine months of 2020 decreased when compared to the same periods of 2019. The decrease in total production costs 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 and 2020 were both affected by incurring fixed costs related to firm processing commitments during outages at the McMahon Gas Plant.

Carbon Tax

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

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period	$ 1,420	$ 1,368	$ 4,591	$ 4,196
Per Boe	$ 0.81	$ 0.80	$ 0.75	$ 0.79

Transportation Costs

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period	$ 11,248	$ 9,981	$ 34,064	$ 30,995
Per Boe	$ 6.43	$ 5.83	$ 5.58	$ 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 third quarter of 2020 increased by 13% when compared to the third quarter of 2019 primarily due to firm transportation commitments which were not used during the third-party gas plant outages in the current quarter. Also contributing to the quarter-over-quarter increase are incremental costs associated with transporting natural gas volumes from the Nig Creek Gas Plant to the Alliance Pipeline in the third quarter of 2020. On a per-Boe basis, transportation costs for the third quarter of 2020 increased by 10% when compared to the third quarter of 2019 primarily due to incurring fixed costs in the current quarter for unused firm transportation during the planned and unplanned outages.

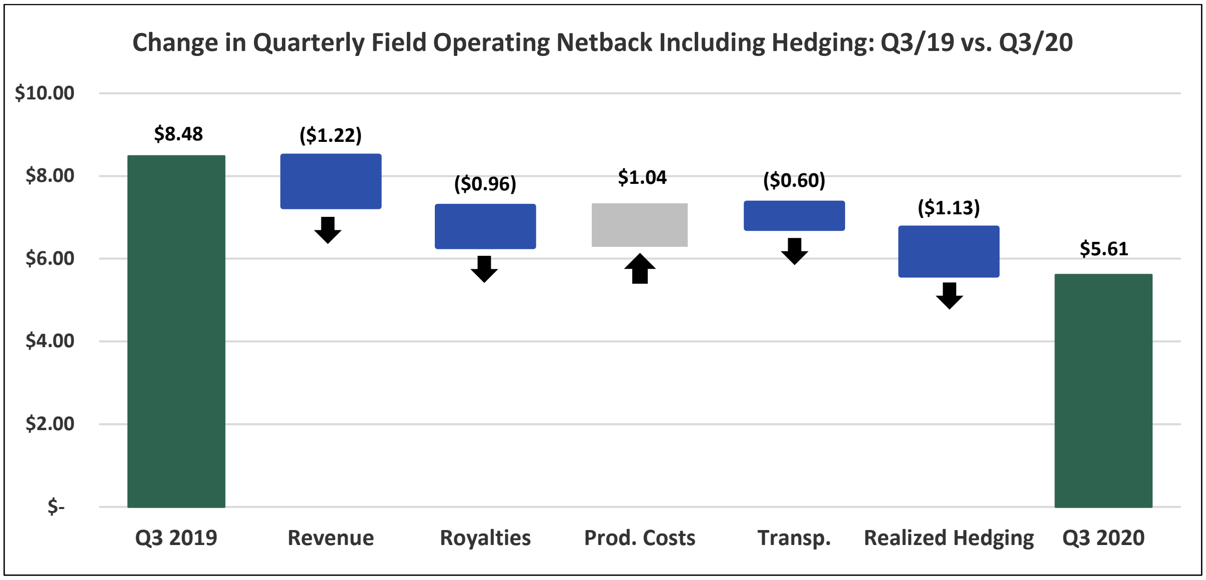
Transportation costs for the first nine months of 2020 increased by 10% when compared to the same period in 2019 primarily due to higher production volumes in 2020 and from incremental costs associated with transporting natural gas volumes from the Nig Creek Gas Plant to the Alliance Pipeline. Transportation costs for the first nine months of 2020 decreased by 4% on a per-Boe basis when compared to the same period of 2019, primarily due to the fixed costs for unused firm transportation during outages having a lesser effect in 2020 (43 days of outages in 2019 compared to 34 days of outages in 2020).

Field Operating Netbacks

Details of field operating netbacks are as follows:

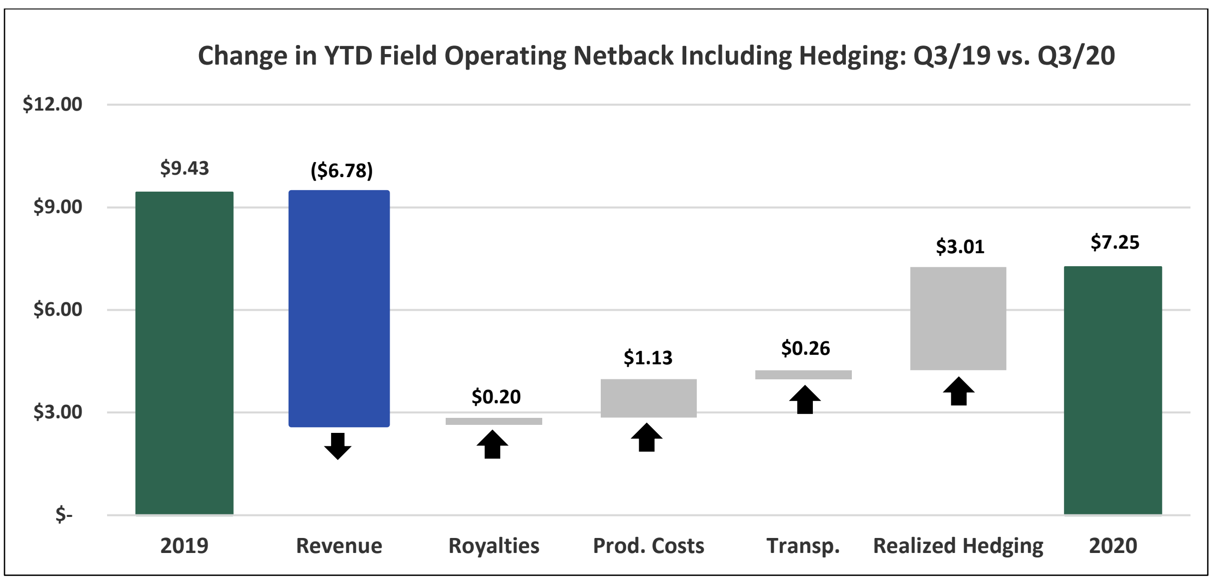
($/Boe)	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Revenue from product sales	17.14	18.36	16.72	23.50
Royalties	(0.77)	0.19	(0.72)	(0.92)
Production costs	(4.84)	(5.88)	(4.83)	(5.96)
Transportation costs	(6.43)	(5.83)	(5.58)	(5.84)
Field operating netback	5.10	6.84	5.59	10.78
Realized gain (loss) on risk management contracts	0.51	1.64	1.66	(1.35)
Field operating netback including hedging	5.61	8.48	7.25	9.43

The field operating netback for the third quarter of 2020 decreased by 34% after hedging compared to the third quarter of 2019.



The field operating netback for the first nine months of 2020 decreased by 23% after hedging compared to the first nine months of 2019. The increase in realized hedging is due to a realized hedging loss of $1.35 per Boe in the first nine months of 2019 compared to a realized gain of $1.66 per Boe in the first nine months of 2020.

The realized hedging gain partially offset decreases in revenue as a result of lower benchmark pricing for crude oil and natural gas.



General and Administrative Costs

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period – before recoveries	$ 1,806	$ 1,728	$ 6,103	$ 6,831
Overhead recoveries	(545)	(369)	(1,405)	(1,393)
Charge for period – net of recoveries	$ 1,261	$ 1,359	$ 4,698	$ 5,438
Per Boe	$ 0.72	$ 0.79	$ 0.77	$ 1.02

General and administrative costs before recoveries for the third quarter of 2020 were largely unchanged when compared to the third quarter of 2019. General and administrative costs before recoveries for the nine months ended September 30, 2020 decreased by 11% compared to the same period of 2019 primarily due to the employee performance bonus paid in early 2020 for 2019 performance being lower than what was paid in the previous year.

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 third quarter of 2020 were lower by 9% compared to the third quarter of 2019 due to an increase in overhead recoveries. Net general and administrative costs on a per-Boe basis decreased by 25% when comparing the first nine 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 Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period(1)	$ 1,928	$ 1,215	$ 5,093	$ 3,648
Effective interest rate(2)	6.0%	5.0%	5.2%	5.1%
Per Boe	$ 1.10	$ 0.71	$ 0.83	$ 0.69

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

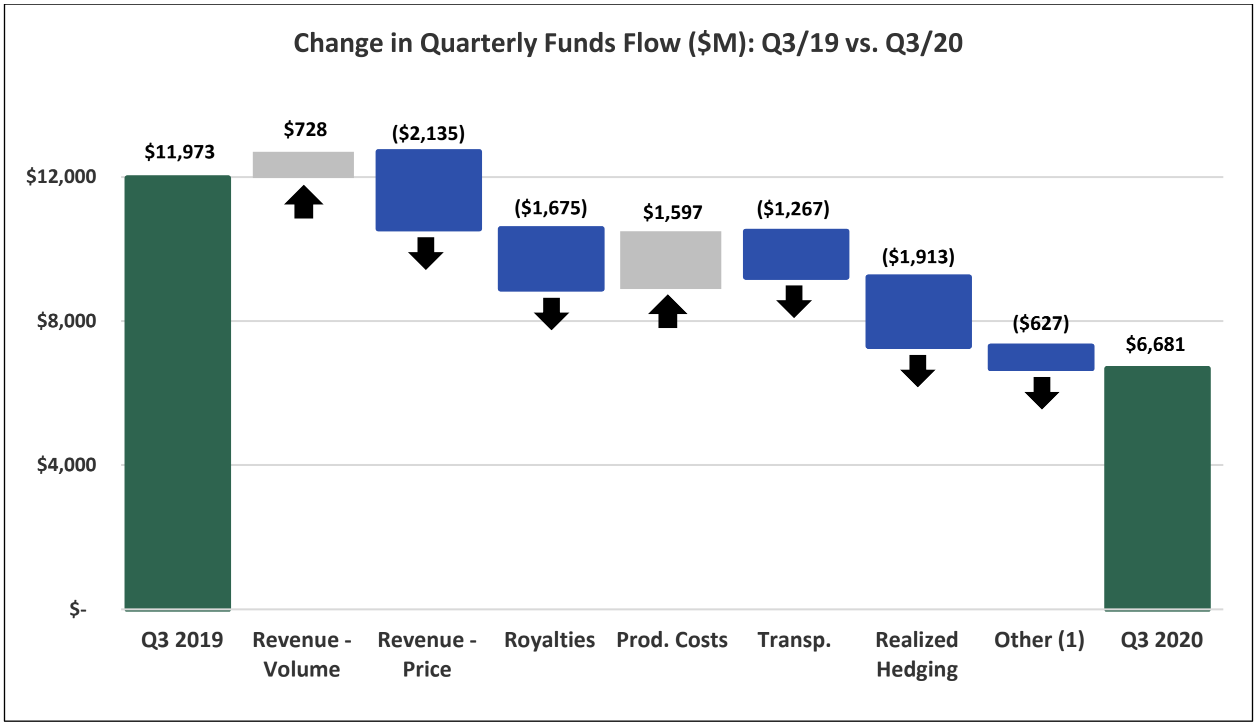
The interest rate on the Company's bank facility is based on bankers' acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt-to-funds-flow ratio.

Interest costs for the third quarter and first nine months of 2020 increased by 59% and 40%, respectively, compared to the same periods of 2019 as a result of higher average bank borrowings which were used to fund the construction of the Nig Creek Gas Plant combined with a higher effective interest rate due to a tightening of credit markets as a result of the COVID-19 pandemic. The effective interest rate for the third quarter of 2020 increased from the third quarter of 2019 due to higher fees from tightening of credit markets and an increase in the Company's debt-to-funds-flow ratio resulting from funding the aforementioned gas plant construction. With an improved commodity price outlook for the fourth quarter of 2020 and for 2021, the expected increase in funds flow will result in stamping fees and interest expense being reduced.

Funds Flow

	Three Months to Sept. 30, 2020		Three Months to Sept. 30, 2019		Nine Months to Sept. 30, 2020		Nine Months to Sept. 30, 2019	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$6,681	$0.05	$11,973	$0.10	$34,474	$0.28	$41,080	$0.34

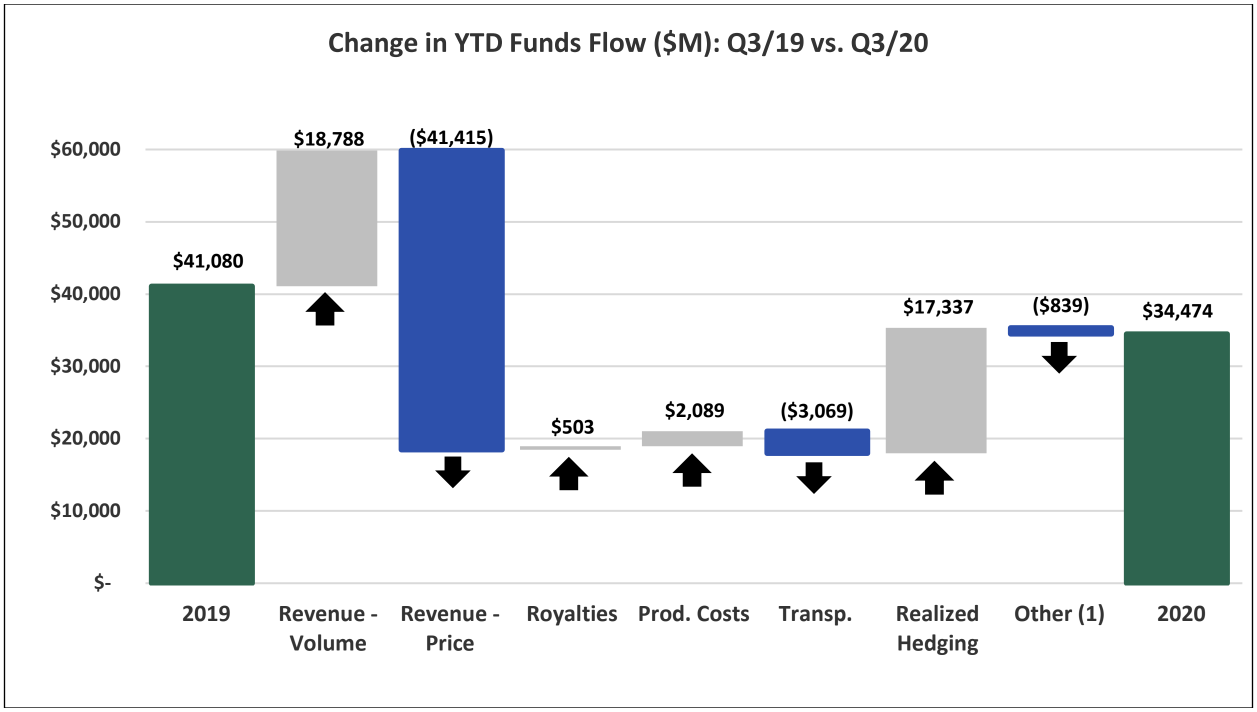
Funds flow, a measure that is not defined under IFRS, is cash generated from operating activities before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies 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 condensate prices, lower condensate production volumes, higher royalties and lower hedging gains were the predominant factors in the 44% decrease in funds flow in the third quarter of 2020 versus the third 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 11% in the third quarter of 2020 compared to 15% in the third 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 nine months of 2020 decreased by 16% from the first nine months of 2019. Funds flow was negatively affected by weaker realized pricing across all products, partially offset by higher production volumes and realized hedging gains. The increase in realized hedging is due to a realized hedging loss in 2019 of $7.2 million compared to a realized hedging gain in the first nine months of 2020 of $10.1 million.

Share-Based Compensation

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Charge for period	$ 483	$ 648	$ 1,387	$ 1,808
Per Boe	$ 0.28	$ 0.38	$ 0.23	$ 0.34

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 25% in the third quarter of 2020 compared to the third quarter of 2019 and decreased by 23% when comparing the nine month periods. The decrease in share-based compensation in both the three and nine month periods is primarily attributable to a lower stock option fair valuation associated with options granted during the fourth quarter of 2019.

Depletion and Depreciation

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Depletion	$ 7,878	$ 7,604	$ 26,917	$ 23,496
Depreciation	2,615	1,946	7,434	5,754
Charge for period	$ 10,493	$ 9,550	$ 34,351	$ 29,250
Per Boe	$ 5.99	$ 5.58	$ 5.62	$ 5.51

Depletion and depreciation increased by 10% in the third quarter of 2020 compared to the same quarter of 2019, and by 17% when comparing the nine month periods, primarily due to an increase in production volumes and higher incremental depreciation associated with the commissioning of the Nig Creek Gas Plant in 2020.

Unrealized Gain (Loss) on Risk Management

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Natural gas	$ (16,176)	$ (1,659)	$ (21,633)	$ 8,303
Liquids[1]	(1,997)	395	1,284	(4,652)
Interest rate	151	(13)	(1,020)	(111)
Unrealized gain (loss) on risk management contracts	$ (18,022)	$ (1,277)	$ (21,369)	$ 3,540
Per Boe	$ (10.30)	$ (0.75)	$ (3.50)	$ 0.67

(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 nine months ended September 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 nine months ended September 30, 2020, the Company recognized a deferred income tax recovery of $5.5 million and $5.3 million, respectively, as a result of $22.4 million and $23.4 million of net loss before taxes, respectively. As at September 30, 2020, the Company had a deferred income tax liability of $4.0 million.

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 nine months ended September 30, 2020 relative to the comparable periods in 2019. For the three and nine months ended September 30, 2020, the unrealized loss on risk management contracts amounted to $18.0 million and $21.4 million, respectively, compared to an unrealized loss of $1.3 million for the three months ended September 30, 2019 and an unrealized gain of $3.5 million for the nine months ended September 30, 2019.

In addition to the unrealized gains and losses on risk management contracts, the increase in net loss in the three and nine months ended September 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 negative 2% in the third quarter of 2020 compared to 9% in the third quarter of 2019, although as mentioned above is distorted by unrealized gains and losses on the Company's risk management contracts.

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Net income (loss)	$ (16,934)	$ (64)	$ (18,087)	$ 8,407
Per basic and diluted share	$ (0.14)	$ (0.00)	$ (0.15)	$ 0.07

INVESTMENT AND FINANCING

Financial Resources and Liquidity

As at September 30, 2020, the Company had an extendible revolving credit facility in the amount of $190 million based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 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 September 30, 2020, debt including working capital deficiency amounted to $138 million. Bank debt including outstanding letters of credit represented approximately 75% utilization of the available credit facility.

As at September 30, 2020, the Company had issued letters of credit in the amount of $13.4 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 third quarter of 2020, the Company incurred capital expenditures of $14.2 million compared to $32.8 million in the third quarter of 2019.

In the first nine months of 2020, the Company incurred capital expenditures of $43.1 million (first nine months of 2019 - $72.9 million) primarily related to costs incurred for completion and start-up of the Nig Creek Gas Plant ($12.2 million), drilling two horizontal wells (1.0 net) at Fireweed and four horizontal wells (4.0 net) at Nig Creek, 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 Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Land and seismic	$ 212	$ 250	$ 546	$ 1,785
Drilling	8,518	3,123	12,521	14,431
Completions	1,618	4,529	11,584	12,483
Facilities	2,018	22,420	14,987	40,287
Equipping and pipelines	1,541	3,585	3,009	4,914
Recompletions and workovers	310	6	395	55
Property acquisition and administrative assets	2	11	46	58
Total field capital expenditures	$ 14,219	$ 33,924	$ 43,088	$ 74,013
Proceeds on disposition of undeveloped land	-	(1,083)	-	(1,083)
Total capital expenditures	$ 14,219	$ 32,841	$ 43,088	$ 72,930

Net capital investment was allocated as follows:

	Three Months to Sept. 30, 2020	Three Months to Sept. 30, 2019	Nine Months to Sept. 30, 2020	Nine Months to Sept. 30, 2019
Exploration and evaluation	$ 212	$ (819)	$ 546	$ 716
Property and equipment	14,007	33,660	42,542	72,214
Total capital expenditures	$ 14,219	$ 32,841	$ 43,088	$ 72,930

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 September 30, 2020 corresponds to the Company's limited field program.

Decommissioning Liability

The Company's decommissioning liability of $32.3 million represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted and inflated amount of the liability at September 30, 2020 was $38.8 million (December 31, 2019 - $38.3 million), with $1.6 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 $4.3 million over five years. In addition, as at the date of this report, the Company has transportation and processing commitments valued at a total of approximately $393 million.

QUARTERLY RESULTS

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

	2020						2019	2018
($000s unless otherwise stated)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue from product sales	30,010	30,191	41,923	48,671	31,417	37,568	55,766	74,799
Funds flow	6,681	10,904	16,889	18,469	11,973	12,590	16,517	30,941
Per share – basic and diluted ($)	0.05	0.09	0.14	0.15	0.10	0.10	0.14	0.25
Net income (loss)	(16,934)	(11,665)	10,512	2,906	(64)	7,864	607	26,810
Per share – basic and diluted ($)	(0.14)	(0.10)	0.09	0.02	(0.00)	0.06	0.00	0.22
Net capital expenditures	14,219	2,394	26,475	23,913	32,841	23,145	16,944	37,100
Average daily production (Boe)	19,027	23,935	23,946	22,375	18,596	19,923	19,823	22,432
Debt including working capital deficiency(1)	137,983	130,317	138,632	128,901	123,342	102,268	91,585	91,020

(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 in 2020 and less than funds flow in 2021;
- planned capital expenditures in 2020 totaling $58 million and $85 to $90 million in 2021, 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 achieve forecasted production levels and number of wells to be drilled and completed as part of the 2020 and 2021 capital programs;
- the expected improvement in the Company’s NGL price in 2020 and that it will be approximately 15% to 20% of WTI in Canadian dollar terms;
- 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 Sept. 30, 2020	As at Sept. 30, 2019	As at Sept. 30, 2018
Accounts receivable	7,455	14,514	15,100
Prepaids and deposits	821	577	845
Less: Accounts payable and accrued liabilities	(17,691)	(30,969)	(21,848)
Working capital deficiency (surplus)	9,415	15,878	5,903
Bank indebtedness	128,568	107,464	78,745
Debt including working capital deficiency	137,983	123,342	84,648

CROCE & ROCE

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

($000s unless otherwise stated)	Twelve Months Ended September 30, 2020	Twelve Months Ended September 30, 2019
Average debt including working capital deficiency(1)	130,663	103,995
Average shareholders' equity(1)	411,577	399,215
Average capital employed	542,240	503,210
Funds flow	52,943	72,021
Interest and finance costs	6,603	4,571
Funds flow plus interest and finance costs	59,546	76,592
CROCE	11%	15%

(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 September 30, 2020	Twelve Months Ended September 30, 2019
Average debt including working capital deficiency(1)	130,663	103,995
Average shareholders' equity(1)	411,577	399,215
Average capital employed	542,240	503,210
Net income (loss)	(15,181)	35,217
Interest and finance costs	6,603	4,571
Deferred income tax expense	(3,845)	7,887
	(12,423)	47,675
ROCE	(2%)	9%

(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 September 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.

QUARTERY SUMMARIES

Thousands of Cdn$, except volumetric and per-share amounts	Q3 2020	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018
FINANCIAL								
Revenue from product sales[1]	30,010	30,191	41,923	48,671	31,417	37,568	55,766	74,799
Funds flow	6,681	10,904	16,889	18,469	11,973	12,590	16,517	30,941
Per share - basic and diluted ($)	0.05	0.09	0.14	0.15	0.10	0.10	0.14	0.25
Net income (loss)	(16,934)	(11,665)	10,512	2,906	(64)	7,864	607	26,810
Per share - basic and diluted ($)	(0.14)	(0.10)	0.09	0.02	(0.00)	0.06	0.00	0.22
Cash return on capital employed (“CROCE”)[2]	11%	12%	12%	12%	15%	18%	20%	21%
Return on capital employed (“ROCE”)[2]	(2%)	2%	7%	4%	9%	11%	8%	10%
Capital expenditures	14,219	2,394	26,475	23,913	32,841	23,145	16,944	37,100
Debt including working capital deficiency[2][3]	137,983	130,317	138,632	128,901	123,342	102,268	91,585	91,020
Common shares (000s)								
Weighted average - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,557	121,557	121,557	121,557	121,853	121,649
Outstanding end of period - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
OPERATIONS								
(Cdn$ per Boe)								
Revenue from product sales[1]	17.14	13.86	19.24	23.64	18.36	20.72	31.26	36.24
Transportation costs	(6.43)	(5.50)	(4.97)	(5.20)	(5.83)	(5.96)	(5.72)	(5.57)
Revenue net of transportation	10.71	8.36	14.27	18.44	12.53	14.76	25.54	30.67
Royalties	(0.77)	(0.44)	(0.97)	(1.59)	0.19	(0.32)	(2.61)	(0.58)
Production costs	(4.84)	(4.50)	(5.17)	(5.67)	(5.88)	(5.89)	(6.09)	(5.46)
Field operating netback[2]	5.10	3.42	8.13	11.18	6.84	8.55	16.84	24.63
Realized gain (loss) on risk management contracts	0.51	2.99	1.26	(0.80)	1.64	(0.22)	(5.38)	(8.65)
General and administrative	(0.72)	(0.72)	(0.86)	(0.70)	(0.79)	(0.68)	(1.60)	(0.55)
Interest and finance costs	(1.08)	(0.68)	(0.74)	(0.71)	(0.69)	(0.71)	(0.61)	(0.45)
Decommissioning expenditures	-	(0.01)	(0.04)	-	-	-	-	-
Funds flow per Boe	3.81	5.00	7.75	8.97	7.00	6.94	9.25	14.98
Barrels of oil equivalent per day (6:1)	19,027	23,935	23,946	22,375	18,596	19,923	19,823	22,432
Natural gas production								
Thousand cubic feet per day	91,526	114,772	115,957	108,679	91,053	97,510	96,537	109,520
Price (Cdn$ per Mcf)[1]	2.47	2.23	2.54	3.28	2.42	2.64	4.49	5.56
Condensate production								
Barrels per day	1,637	2,305	2,623	2,416	1,856	2,081	2,199	2,453
Price (Cdn$ per barrel)[1]	46.79	25.92	60.66	66.56	63.45	71.12	62.77	58.74
NGL production								
Barrels per day	2,136	2,501	1,998	1,846	1,564	1,591	1,534	1,726
Price (Cdn$ per barrel)[1]	10.95	6.23	3.27	6.11	2.29	4.87	31.43	35.09
Wells drilled (net)	4.0	-	1.0	-	1.0	-	5.0	4.0
Wells completed (net)	-	-	3.5	-	5.0	-	-	2.5

(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 24 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	September 30, 2020	December 31, 2019
ASSETS			
Current			
Accounts receivable	12	$ 7,455	$ 21,961
Prepaids and deposits		821	764
Risk management contracts	12	-	1,113
		8,276	23,838
Exploration and evaluation	3	99,870	99,737
Property and equipment	4	502,750	490,264
Right-of-use asset	7	2,329	2,657
		$ 613,225	$ 616,496
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current			
Accounts payable and accrued liabilities		$ 17,691	$ 30,018
Current portion of decommissioning liability	8	1,551	448
Current portion of lease liability	7	510	507
Risk management contracts	12	18,305	2,042
		38,057	33,015
Bank indebtedness	5	128,568	121,608
Risk management contracts	12	4,897	904
Lease liability	7	1,949	2,234
Decommissioning liability	8	30,704	27,667
Deferred income taxes		4,042	9,360
		208,217	194,788
Shareholders' equity			
Share capital	9	391,444	391,444
Contributed surplus	10	18,992	17,605
Retained earnings		(5,428)	12,659
		405,008	421,708
Commitments	14		
		$ 613,225	$ 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 Sept. 30 2020	Three Months Ended Sept. 30 2019	Nine Months Ended Sept. 30 2020	Nine Months Ended Sept. 30 2019
Revenue					
Revenue from product sales	6	$ 30,010	$ 31,417	$ 102,124	$ 124,751
Royalties		(1,343)	332	(4,399)	(4,902)
		28,667	31,749	97,725	119,849
Realized gain (loss) on risk management contracts	12	898	2,811	10,148	(7,189)
		29,565	34,560	107,873	112,660
Expenses					
Production		8,471	10,068	29,522	31,611
Transportation		11,248	9,981	34,064	30,995
General and administrative		1,261	1,359	4,698	5,438
Share-based compensation	10	483	648	1,387	1,808
Depletion and depreciation	4, 7	10,493	9,550	34,351	29,250
Exploration and evaluation costs expensed	3	-	-	450	1,119
Accretion	8	70	120	256	372
Interest and finance costs		1,928	1,215	5,093	3,648
Unrealized (gain) loss on risk management contracts	12	18,022	1,277	21,369	(3,540)
Unrealized revaluation loss on investment		1	81	88	98
		51,977	34,299	131,278	100,799
Net income (loss) and comprehensive income (loss)		(22,412)	261	(23,405)	11,861
Deferred income tax expense (recovery)		(5,478)	325	(5,318)	3,454
Net income (loss) and comprehensive income (loss)		$ (16,934)	$ (64)	$ (18,087)	$ 8,407
Net income (loss) per share – basic and diluted	11	$ (0.14)	$ (0.00)	$ (0.15)	$ 0.07

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Nine Months Ended September 30, 2020	
	Notes	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total Equity
Balance, beginning of period		$ 391,444	$ 17,605	$ 12,659	$ 421,708
Net loss for the period		-	-	(18,087)	(18,087)
Share-based compensation	10	-	1,387	-	1,387
Balance, end of period		$ 391,444	$ 18,992	$ (5,428)	$ 405,008

(Canadian $000s) (unaudited)				Nine Months Ended September 30, 2019	
	Notes	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, beginning of period		$ 391,444	$ 15,141	$ 1,346	$ 407,931
Net income for the period		-	-	8,407	8,407
Share-based compensation	10	-	1,808	-	1,808
Balance, end of period		$ 391,444	$ 16,949	$ 9,753	$ 418,146

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Notes	Three Months Ended Sept. 30 2020	Three Months Ended Sept. 30 2019	Nine Months Ended Sept. 30 2020	Nine Months Ended Sept. 30 2019
Operating activities					
Net income (loss) for the period		$ (16,934)	$ (64)	$ (18,087)	$ 8,407
Non-cash items:					
Unrealized (gain) loss on risk management	12	18,022	1,277	21,369	(3,540)
Depletion, depreciation and accretion	4, 7, 8	10,563	9,670	34,607	29,622
Share-based compensation	10	483	648	1,387	1,808
Lease interest	7	31	36	98	112
Exploration and evaluation costs expensed	3	-	-	450	1,119
Unrealized revaluation loss on investment		1	81	88	98
Deferred income tax expense (recovery)		(5,478)	325	(5,318)	3,454
Decommissioning expenditures	8	(7)	-	(120)	-
Funds flow		6,681	11,973	34,474	41,080
Net change in non-cash working capital items	13	4,831	(1,202)	6,995	11,702
		11,512	10,771	41,469	52,782
Financing activities					
Payment of lease liability	7	(127)	(125)	(380)	(374)
Increase (decrease) in bank indebtedness		(790)	22,892	6,960	20,688
		(917)	22,767	6,580	20,314
Investing activities					
Additions to property and equipment	4	(14,007)	(33,660)	(42,542)	(72,214)
Additions to exploration and evaluation assets	3	(212)	819	(546)	(716)
Net change in non-cash working capital items	13	3,624	(697)	(4,961)	(166)
		(10,595)	(33,538)	(48,049)	(73,096)
Change in cash during the period		-	-	-	-
Cash, beginning of period		-	-	-	-
Cash, end of period		$ -	$ -	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2020 and December 31, 2019 and for the three and nine months ended September 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 November 10, 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

	Nine Months Ended September 30, 2020	Year Ended December 31, 2019
Balance, beginning of period	$ 99,737	$ 102,277
Additions	546	2,169
Dispositions	-	(1,083)
Expiries - exploration and evaluation costs expensed	(450)	(1,140)
Future decommissioning costs	37	178
Transfer to property and equipment	-	(2,664)
Balance, end of period	$ 99,870	$ 99,737

As at September 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

	Nine Months Ended September 30, 2020	Year Ended December 31, 2019
Cost		
Balance, beginning of period	$ 746,515	$ 646,983
Additions	42,542	95,757
Future decommissioning costs	3,967	1,111
Transfer from exploration and evaluation assets	-	2,664
Balance, end of period	$ 793,024	$ 746,515
Accumulated depletion and depreciation		
Balance, beginning of period	$ (256,251)	$ (216,182)
Depletion and depreciation	(34,023)	(40,069)
Balance, end of period	$ (290,274)	$ (256,251)
Net book value, beginning of period	$ 490,264	$ 430,801
Net book value, end of period	$ 502,750	$ 490,264

As at September 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 September 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 September 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 September 30, 2020, debt including outstanding letters of credit amounted to $142.0 million, representing approximately 75% of the available credit facility.

As at September 30, 2020, the Company had issued letters of credit in the amount of $13.4 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 September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Natural gas	$ 20,813	$ 20,252	$ 70,998	$ 82,652
Condensate	7,046	10,836	26,961	36,726
NGL	2,151	329	4,165	5,373
Total	$ 30,010	$ 31,417	$ 102,124	$ 124,751

Storm's revenue was generated mostly in British Columbia where production was sold primarily to two major energy customers with investment grade credit ratings which accounted for 83% and 82% of the Company's total revenue from product sales for the three and nine months ended September 30, 2020, respectively (September 30, 2019 - 83% 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 nine months ended September 30, 2020, 57% received Chicago pricing, 15% received BC Station 2 pricing, 13% received AECO pricing, 10% received Sumas pricing, and the remaining 5% 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:

	Nine Months Ended September 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	(328)	(437)
Balance, end of period	$ (765)	$ (437)
Net book value, beginning of period	$ 2,657	$ 3,094
Net book value, end of period	$ 2,329	$ 2,657

As at September 30, 2020, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is $2.3 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:

	Nine Months Ended September 30, 2020		Year Ended December 31, 2019	
Balance, beginning of period	$	2,741	$	3,094
Lease payments		(380)		(500)
Lease interest		98		147
Balance, end of period	$	2,459	$	2,741
Less current portion		510		507
Long-term portion	$	1,949	$	2,234

The lease liability was measured at the present value of the remaining lease payments discounted at the Company's weighted average incremental borrowing rate of 5%.

As at September 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 $2.8 million.

Short-term leases are leases with a lease term of twelve months or less. During the nine months ended September 30, 2020, short-term lease costs of approximately $1.4 million (September 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 $38.8 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 1.1% (December 31, 2019 - 1.7%) and an inflation rate of 1.3% (December 31, 2019 - 1.4%) was used to calculate the present value of the decommissioning obligation, amounting to $32.3 million at September 30, 2020.

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

	Nine Months Ended September 30, 2020		Year Ended December 31, 2019	
Balance, beginning of period	$	28,115	$	26,334
Obligations incurred		781		2,706
Obligations settled		(120)		(246)
Change in estimates(1)		3,223		(1,171)
Accretion expense		256		492
Balance, end of period	$	32,255	$	28,115
Less current portion		1,551		448
Long-term portion	$	30,704	$	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 September 30, 2020	121,557	$	391,444

For the period from January 1, 2020 to November 10, 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 September 30, 2020, a total of 12,155,681 common shares were available for issuance. At September 30, 2020, 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.

At November 10, 2020, the date of this report, options in respect of 10,097,100 common shares were issued and outstanding and options in respect of 2,058,581 common shares are available for future issue.

Details of the options outstanding at September 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 September 30, 2020	10,277	$ 2.72
Number exercisable at September 30, 2020	4,734	$ 3.81

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	2.8	$ 1.63	886	$ 1.83
$2.86 - $4.50	2,631	1.2	$ 2.98	1,834	$ 3.04
$4.51 - $5.50	2,014	0.2	$ 5.39	2,014	$ 5.39
Total	10,277	1.9	$ 2.72	4,734	$ 3.81

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

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the nine months ended September 30, 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 $0.5 million and $1.4 million was charged to the consolidated statement of income (loss) during the three and nine months to September 30, 2020, respectively (2019 - $0.6 million and $1.8 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 September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Net income (loss) for the period	$ (16,934)	$ (64)	$ (18,087)	$ 8,407
Weighted average number of common shares outstanding – basic	121,557	121,557	121,557	121,557
Dilutive effect of stock 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	$ (0.14)	$ (0.00)	$ (0.15)	$ 0.07

(1) For the three and nine months ended September 30, 2020, the Company incurred net losses and therefore there were no dilutive effects of stock options. For the three and nine months ended September 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 nine months ended September 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 September 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	$ 2,798	$ (2,798)	$ -
Long-term asset	817	(817)	-
Current liability	(21,103)	2,798	(18,305)
Long-term liability	(5,714)	817	(4,897)
Net position	$ (23,202)	$ -	$ (23,202)

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 September 30, 2020, the Company's two major energy customers with investment grade credit ratings accounted for $6.9 million of total receivables (September 30, 2019 - $9.3 million from two major customers) and 83% and 82% of total revenues for the three and nine months ended September 30, 2020, respectively (three and nine months ended September 30, 2019 - 83% 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 September 30, 2020, there were no receivables outstanding for more than 90 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at September 30, 2020.

The maximum exposure to credit risk at September 30, 2020 was the carrying amount of accounts receivable of $7.5 million. No receivables were impaired at September 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 September 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 November 10, 2020		**2020**	**2021**	**2022**
Natural Gas				
NYMEX swap	Mmbtu/d	3,650	2,584	-
	US$/Mmbtu	$2.49	$2.44	-
NYMEX swap	Mmbtu/d	842	6,814	-
	Cdn$/Mmbtu	2.86	$3.36	-
NYMEX collar	Mmbtu/d	9,685	1,575	1,110
	US$/Mmbtu	$1.94 - $2.45	$2.57 - $3.04	$2.72 - $3.67
NYMEX collar	Mmbtu/d	18,825	5,159	1,480
	Cdn$/Mmbtu	$2.79 - $3.34	$3.50 - $4.04	$3.53 - $4.13
Chicago swap	Mmbtu/d	-	752	4,975
	US$/Mmbtu	-	$3.11	$2.52
Chicago swap	Mmbtu/d	4,484	17,856	1,110
	Cdn$/Mmbtu	$3.55	$3.20	$3.65
AECO swap	GJ/d	8,000	7,682	-
	Cdn$/GJ	$1.98	$2.16	-
AECO collar	GJ/d	10,609	3,945	1,488
	Cdn$/GJ	$1.97 - $2.53	$1.97 - $2.53	$2.20 - $3.11
BC Station 2 swap	GJ/d	15,300	22,773	8,804
	Cdn$/GJ	$1.95	$2.00	$2.33

As at November 10, 2020		2020	2021	2022
Natural Gas (continued)				
Sumas swap	Mmbtu/d	1,685	-	-
	Cdn$/Mmbtu	$3.07	-	-
Natural Gas Differential Swaps				
NYMEX:Chicago	Mmbtu/d	14,185	12,834	1,110
	US$/Mmbtu	($0.28)	($0.25)	$0.09
NYMEX:Chicago	Mmbtu/d	18,825	3,592	1,480
	Cdn$/Mmbtu	($0.29)	$0.06	$0.07
AECO:BC Station 2	GJ/d	4,641	1,726	1,488
	Cdn$/GJ	($0.10)	($0.10)	($0.01)
Crude Oil				
WTI swap	Bbls/d	950	750	-
	Cdn$/Bbl	$59.75	$53.02	-
WTI collar	Bbls/d	800	650	-
	Cdn$/Bbl	$57.81 - $67.60	$50.54 - $59.93	-
Crude Oil Differential Swaps				
WTI:C5	Bbls/d	1,100	747	-
	Cdn$/Bbl	($6.67)	($3.99)	-
Propane				
Conway swap	Bbls/d	200	50	-
	Cdn$/Bbl	$28.25	$27.30	-

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		
Oct 2020	14,028 Mmbtu at BC Station 2	Sumas less US$0.69/Mmbtu
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
Oct 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 September 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	Oct 2020 – May 2022	1.949%
One-month bankers' acceptance - CDOR(1)	Jan 2020	$10 million	Oct 2020 – Jan 2023	1.943%
One-month bankers' acceptance - CDOR(1)	Jan 2020	$15 million	Oct 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 September 30, 2020 was a net liability position of $23.2 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 nine months ended September 30, 2020, this resulted in unrealized mark-to-market losses of $18.0 million and $21.4 million, respectively, (September 30, 2019 - unrealized mark-to-market loss of $1.3 million for the three month period and an unrealized mark-to-market gain of $3.5 million for the nine month period) 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 $0.9 million and $10.1 million, respectively, for the three and nine months ended September 30, 2020 (September 30, 2019 - realized gain of $2.8 million for the three month period and a realized loss of $7.2 million for the nine month period).

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 September 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.

	Nine Months Ended September 30, 2020
Factor	Gain/(Loss)
Increase of US$5.00/Bbl in the price of WTI[(1)]	$ (3,296)
Decrease of US$5.00/Bbl in the price of WTI[(1)]	$ 3,296
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (4,100)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 4,100
Increase of 100 basis points (1%) in interest rates	$ 701
Decrease of 100 basis points (1%) in interest rates	$ (701)

(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 September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Accounts receivable	$ 3,332	$ (3,613)	$ 14,418	$ 14,650
Prepaids and deposits	(187)	(190)	(57)	276
Accounts payable and accrued liabilities	5,310	1,904	(12,327)	(3,390)
Change in non-cash working capital	$ 8,455	$ (1,899)	$ 2,034	$ 11,536
Relating to:				
Operating activities	$ 4,831	$ (1,202)	$ 6,995	$ 11,702
Investing activities	3,624	(697)	(4,961)	(166)
Change in non-cash working capital	$ 8,455	$ (1,899)	$ 2,034	$ 11,536
Interest paid during the period	$ 1,696	$ 1,218	$ 4,831	$ 3,523
Income taxes paid during the period	$ -	$ -	$ -	$ -

14. COMMITMENTS

At September 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	$ 16,036	$ 62,133	$ 51,503	$ 27,494	$ 27,629	$ 208,462	$ 393,257
Office lease[(1)]	89	356	356	356	356	385	1,898
Total	$ 16,125	$ 62,489	$ 51,859	$ 27,850	$ 27,985	$ 208,847	$ 395,155

CORPORATE INFORMATION

Officers

Brian Lavergne
President & Chief Executive Officer

Robert S. Tiberio
Chief Operating Officer

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
President & Chief Executive Officer

Sheila A. Leggett (2)

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

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Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol "SRX"

Solicitors

Stikeman Elliott LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

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

Executive Offices

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

Abbreviations

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

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