STORM RESOURCES

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
FINANCIAL		
Revenue from product sales(1)	52,102	44,392
Funds flow	23,519	17,958
Per share - basic and diluted ($)	0.19	0.15
Net income	8,894	20,631
Per share - basic and diluted ($)	0.07	0.17
Operations capital expenditures(2)	22,900	27,357
Debt including working capital deficiency(2)(3)	105,585	97,864
Common shares (000s)		
Weighted average - basic	121,557	121,442
Weighted average - diluted	121,557	121,720
Outstanding end of period – basic	121,557	121,557
OPERATIONS		
(Cdn$ per Boe)		
Revenue from product sales(1)	29.37	29.10
Transportation costs	(5.59)	(5.50)
Revenue net of transportation	23.78	23.60
Royalties	(1.71)	(1.88)
Production costs	(5.55)	(5.84)
Field operating netback(2)	16.52	15.88
Realized loss on hedging	(1.19)	(2.31)
General and administrative	(1.42)	(1.10)
Interest and finance costs	(0.64)	(0.71)
Funds flow per Boe	13.27	11.76
Barrels of oil equivalent per day (6:1)	19,708	16,947
Natural gas production		
Thousand cubic feet per day	96,068	84,093
Price (Cdn$ per Mcf)(1)	3.83	4.20
Condensate production		
Barrels per day	2,062	1,758
Price (Cdn$ per barrel)(1)	76.12	64.40
NGL production		
Barrels per day	1,635	1,174
Price (Cdn$ per barrel)(1)	33.05	23.09
Wells drilled (100% working interest)	-	6.0
Wells completed (100% working interest)	3.0	4.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements including field operating netback, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 27 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2018 FIRST QUARTER HIGHLIGHTS

- Production increased by 16% on a per-share basis from the prior year to 19,708 Boe per day and was consistent with guidance (19,500 to 20,500 Boe per day). Compared to the previous quarter, production increased by 10% on a per-share basis.

- Liquids production (condensate plus NGL) grew by 26% year over year (versus 14% growth for natural gas) with liquids representing 19% of total production and 36% of production revenue.

- At the end of the quarter, there was an inventory of 10 Montney horizontal wells (10.0 net) at Umbach that had not started producing which includes three completed wells. Two horizontal wells (2.0 net) started production in the quarter.

- Horizontal well performance at Umbach continues to improve as length is increased. Compared to wells completed in 2014 to 2016, the wells completed in 2017 are 35% longer (1,750 metres versus 1,300 metres), declines have been flatter, and first year average rates are expected to be more than 15% higher based on production history to date.

- A pad with three horizontal wells was completed on the Nig land block in the first quarter with lengths averaging 2,090 metres. The first well started production on April 10th and has averaged 7.3 Mmcf per day raw gas plus 252 barrels per day of field condensate over the first 30 calendar days of production based on field estimates (approximately 1,480 Boe per day sales including 26% liquids). Consistent with other new wells, the rate on this well has been restricted to manage initial fluid volumes.

- Revenue net of transportation costs was $23.78 per Boe which is an increase of 1% from last year as higher liquids pricing offset a 9% decrease in the natural gas price.

- The operating netback was $16.52 per Boe, an improvement of 4% compared to last year with production costs declining by 5% to $5.55 per Boe as a result of continuing production growth.

- Funds flow increased to $23.5 million, or $13.27 per Boe, and was the highest quarterly funds flow achieved since inception. On a per-share basis, funds flow increased to $0.19 per share which is a year-over-year increase of 27%. The improvement was largely the result of increased production volumes.

- Net income was $8.9 million or $0.07 per share which is a decrease from $20.6 million last year. The decrease was largely the result of an $18.2 million change in the unrealized gain (loss) on hedges which is a non-cash expense and represents the change in the fair market value of future hedges.

- Capital investment was $22.9 million which was less than funds flow and was consistent with guidance ($23.0 million). Investment included $8.9 million to complete a three well pad on the Nig land block and $12.8 million to expand infrastructure at Umbach (12-kilometre gathering pipeline to Nig plus purchase an additional compressor).

- The balance sheet remains strong with debt including the working capital deficiency being $105.6 million which was 1.1 times annualized first quarter funds flow. Subsequent to quarter end, the bank credit facility was increased to $180 million from $165 million.

- Commodity price hedges continue to be added and currently protect approximately 47% of forecast production for the remainder of 2018.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 111,000 net acres (157 net sections). During the first quarter, two sections of land were purchased at Crown land sales. To date, Storm has drilled 69 horizontal wells (65.4 net).

Field activity in the first quarter included completing the first three horizontal wells (3.0 net) on the Nig land block and constructing a 12-kilometre gathering pipeline to connect the Nig wells back to the field compression facility. Two horizontal wells (2.0 net) started production in the quarter which left an inventory of 10 horizontal wells (10.0 net) that had not started producing at the end of the quarter including three completed wells.

Preliminary indications from the wells at Nig are encouraging. One well has started production with the rate being restricted to average 7.3 Mmcf per day raw gas plus 252 barrels per day of free condensate over the first 30 calendar days since start-up on April 10th (approximately 1,480 Boe per day sales including 26% liquids). The remaining two wells will start production over the next three months. The wells at Nig have average completed lengths of 2,090 metres which is 60% longer than the average well completed in 2014 to 2016 and 20% longer than the average well completed in 2017.

Drilling in the second half of 2018 is expected to be focused on the Nig land block or at South Umbach where condensate-gas ratios are higher. In addition, horizontal well lengths will be further increased to approximately 2,400 metres.

Since 2013, approximately $111.0 million has been invested in building out infrastructure (pipelines and facilities) with current capacity totaling 115 Mmcf per day raw gas from three field compression facilities. Throughput in the first quarter averaged 102 Mmcf per day raw gas. Capacity can be increased to 150 Mmcf per day with the installation of an additional compressor which was purchased and moved to site in the first quarter of 2018 at a cost of $4.7 million (requires additional $2.0 million for installation). The increased compression capacity would support growth in corporate production to approximately 27,000 Boe per day.

Storm's produced raw natural gas is sour (approximately 1.2% H_2S) with 86% directed to the McMahon Gas Plant in the first quarter and 14% directed to the Stoddart Gas Plant. Firm processing commitments are 65 Mmcf raw gas per day at McMahon (5 to 15 year terms) and 15 Mmcf per day at Stoddart (1 year term).

A summary of horizontal wells is provided below. The primary focus since late 2016 has been to improve rates and reserves by drilling longer wells (future wells will be approximately 2,400 metres long). The majority of wells are initially rate restricted to manage fluid rates and, as a result, the IP90 and IP180 rates may not be indicative of longer term performance. More information on well performance is available in the presentation on Storm's website.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP90 Cal Day Mmcf/d Raw	IP180 Cal Day Mmcf/d Raw	IP365 Cal Day Mmcf/d Raw
2014 12 hz's(1)	19	1,170 m	$4.6 million $3,950 per metre	4.9 Mmcf/d 12 hz's	4.4 Mmcf/d 12 hz's	3.5 Mmcf/d 12 hz's
2015 11 hz's	22	1,360 m	$4.5 million $3,300 per metre	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 11 hz's
2016 10 hz's	25	1,300 m	$3.7 million $2,850 per metre	5.1 Mmcf/d 10 hz's	4.2 Mmcf/d 10 hz's	3.5 Mmcf/d 10 hz's
2017 12 hz's	34	1,750 m	$4.2 million $2,400 per metre	5.0 Mmcf/d 11 hz's	4.4 Mmcf/d 8 hz's	3.9 Mmcf/d 3 hz's
2018 3 hz's	37	2,090 m	$5.4 million $2,580 per metre			

(1) 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth by continually layering in hedges to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that approximately 80% of Storm's liquids production is priced in reference to WTI. The current hedge position is summarized below and protects approximately 47% of forecast production for 2018.

2018 Q2 – Q4		
Crude Oil	1,500 Bpd	WTI Cdn$65.78/Bbl floor, Cdn$70.64/Bbl ceiling
Propane	300 Bpd	Conway Cdn$39.55/Bbl
Natural Gas	44,100 Mmbtu/d (37,200 Mcf/d)	Chicago Cdn$3.60/Mmbtu(1)
	9,000 Mmbtu/d (7,600 Mcf/d)	Sumas Cdn$3.02/Mmbtu
	3,000 GJ/d (2,400 Mcf/d)	Station 2 - AECO basis -$0.345/GJ
2019		
Crude Oil	700 Bpd	WTI Cdn$68.81/Bbl floor, Cdn$75.34/Bbl ceiling
Natural Gas	24,300 Mmbtu/d (20,500 Mcf/d)	Chicago Cdn$3.25/Mmbtu(1)

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

Total firm transportation capacity increased to 102 Mmcf per day in April 2018 with the addition of 13 Mmcf per day of capacity to AECO. Firm capacity on the Alliance Pipeline to Chicago totals 55 Mmcf per day with preferential interruptible capacity increasing this by 14 Mmcf per day (increasing total transportation capacity to 116 Mmcf per day sales). Using firm capacity of 102 Mmcf per day sales, approximately 54% to 68% of natural gas will be sold at Chicago pricing, 11% at Sumas pricing less a marketing adjustment, 5% at ATP pricing, and 16% to 30% at Station 2 or AECO pricing. During the first quarter, 64% of natural gas production was sold in Chicago. Natural gas production exceeding firm capacity would be directed to Chicago and/or Station 2 using interruptible pipeline capacity (depending on which sales point offers a higher price net of transportation tariffs).

OUTLOOK

For the second quarter of 2018, production is forecast to be 19,500 to 20,500 Boe per day with production to date in the second quarter averaging 20,200 Boe per day based on field estimates. Capital investment is expected to be $6.0 million which is forecast to be less than funds flow using forecast commodity prices and will result in debt being reduced by approximately $15.0 million.

Updated guidance for 2018 is provided in the table below. Forecast commodity prices have been updated to reflect pricing to date and the approximate forward strip for the remainder of the year (changes daily). Capital investment has been reduced to the lower end of what was provided in previous guidance given that any incremental growth in natural gas production would be sold at Station 2 and the natural gas price at Station 2 remains below what is required to justify growing production. A Station 2 price greater than $1.50 to $1.75 per GJ is required to provide reasonable full-cycle rates of return and justify growth. Forecast production is based on a 7.5 Bcf type curve for future horizontal wells at Umbach.

2018 Guidance

	Previous March 1, 2018	Current May 15, 2018
Cdn$/US$ exchange rate	0.80	0.79
Chicago daily natural gas - US$/Mmbtu	$2.60	$2.60
Sumas monthly natural gas - US$/Mmbtu	$1.90	$1.95
AECO daily natural gas - Cdn$/GJ	$1.40	$1.35
Station 2 daily natural gas - Cdn$/GJ	$1.05	$1.20
WTI - US$/Bbl	$56.00	$64.00
Edmonton light oil - Cdn$/Bbl	$64.00	$73.00
Est revenue net of transport (excl hedges) - $/Boe	$17.00 - $18.50	$19.00 - $19.50
Est operating costs - $/Boe	$5.75	$5.75
Est royalty rate (% revenue before hedging)	6% - 8%	6% - 8%
Est operations capital investment (excl A&D) - $ million	$55.0 - $90.0	$55.0 - $65.0
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $7.0
- $/Boe	$0.70 - $0.95	$0.78 - $0.95
Est interest expense - $ million	$4.5 - $5.5	$4.0
Forecast fourth quarter production - Boe/d	20,000 - 27,000	20,000 - 21,000
% liquids	18% liquids	18% liquids
Forecast annual production - Boe/d	20,000 - 23,000	20,000 - 21,000
% liquids	18% liquids	18% liquids
Est annual funds flow at 20,000 Boe/d - $ million	$70.0 - $78.0	$76.0 - $80.0
Umbach horizontal wells drilled - gross	3 - 12 (3.0 - 12.0 net)	3 - 6 (3.0 - 6.0 net)
Umbach horizontal wells completed - gross	11 - 17 (11.0 - 17.0 net)	8 - 11 (8 - 11.0 net)
Umbach horizontal wells connected - gross	11 - 16 (11.0 - 16.0 net)	10 (10.0 net)

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	AECO Daily (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
Nov 14, 2017	$2.80	$1.30 - $1.70	$1.80 - $2.10	$55.0 - $90.0	20,000 - 27,000	20,000 - 23,000
Mar 1, 2018	$2.60	$1.05	$1.40	$55.0 - $90.0	20,000 - 27,000	20,000 - 23,000
May 15, 2018	**$2.60**	**$1.20**	**$1.35**	**$55.0 - $65.0**	**20,000 - 21,000**	**20,000 - 21,000**

Although Western Canadian natural gas prices were reasonably strong in the first quarter, second quarter prices have weakened with recent maintenance restrictions on TCPL's NGTL system and Enbridge's T-south pipeline that have restricted exports from Western Canada. Daily prices to date in the second quarter have averaged $1.07 per GJ at AECO and $1.11 per GJ at Station 2 (versus $1.97 per GJ and $1.81 per GJ respectively in the first quarter). The effect of the maintenance restrictions has been exacerbated by year-over-year production growth of approximately 1.0 Bcf per day. Production is likely to decline at current prices given the reduction in the gas directed rig count and the reduced level of capital investment announced by several larger gas weighted producers. However, without production declines, it is going to be a volatile summer for Western Canadian natural gas prices given additional maintenance restrictions planned by both TCPL and Enbridge through to the end of September. The impact on Storm will be partially mitigated by increasing liquids production and with diversified natural gas sales where 65% to 79% of forecast production is being sold in the US at Chicago and Sumas.

Natural gas prices in the US have been stable with the Chicago daily price averaging US$2.95 per Mmbtu in the first quarter and US$2.73 per Mmbtu to date in the second quarter. Data from the US EIA for the first two months of 2018 shows a large year-over-year increase in demand for natural gas at 13.1 Bcf per day (majority from electric power generation and residential) plus net exports have increased by 0.9 Bcf per day year-over-year. The growth in demand has more than offset year-over-year growth in dry gas production which has been a robust 7.0 Bcf per day. This has resulted in a steep decline in natural gas storage levels which are 863 Bcf below last year for the week ended May 4th. Over the summer, demand for natural gas to refill storage is likely to be supportive of US natural gas prices.

For 2018, production is expected to remain at 20,000 to 21,000 Boe per day unless there is an improvement in the natural gas price at Station 2. This represents year-over-year production growth of 25%. Production can be increased relatively quickly given the current inventory of standing wells and existing field compression capacity at Umbach which supports growth to 27,000 Boe per day. Planning for 2019 is underway with the focus being to continue growing production and funds flow by increasing liquids production.

With a large, multi-year drilling inventory in the higher quality and liquids-rich Montney formation at Umbach, Storm's business plan continues to be focused on adding value by converting resource into debt adjusted funds flow growth on a per-share basis.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 15, 2018

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

Oil and Gas Metrics - Oil and gas metrics, including FD&A, recycle ratio, FDC, and reserves life index or RLI, do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods.

Initial Production Rates - References to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

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 May 15, 2018 for the three months ended March 31, 2018.

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 months ended March 31, 2018. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2018, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2017, and (iii) the press release issued by the Company on May 15, 2018, and other operating and financial information included in this report. All of these documents as well as the Company's Annual Information Form dated March 29, 2018 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 May 15, 2018.

See "Forward Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 25 to 27.

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 months ended March 31, 2018, 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, 2017 and updated for new standards, as applicable, in Note 3 of the financial statements for the three months ended March 31, 2018. 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 immediately prior three month period ended December 31, 2017 and for the three month period ended March 31, 2017.

OPERATIONAL AND FINANCIAL RESULTS

Overview

While record supply growth and egress concerns in North America continue to keep a lid on natural gas prices, reasonably cold winter weather that extended into April led to strong pulls from storage and helped to support natural gas prices through the first quarter of 2018. Despite a relatively supportive storage outlook, particularly in the US where storage levels are trending well below the five-year average, the market remains fixated on the robust supply growth and the assumed ease with which storage will be re-filled. Given these market dynamics, natural gas prices in the first quarter of 2018 were slightly weaker than this time last year, with Storm's realized price down 9% from the first quarter of 2017. Based on the uncertainty surrounding natural gas prices, particularly through the coming summer months, Storm expects to continue to maintain production at a level that meets firm processing and transportation commitments. Storm remains well positioned in regards to market access with firm transportation agreements totaling 102 Mmcf per day in 2018, the bulk of which is directed to the Chicago market (54% to 68%).

While representing only 19% of the Company's total production base, condensate (includes field condensate and plant pentanes) and NGL (includes butane and propane) contributed 36% to the Company's top line revenue in the first quarter, with continuing strength in condensate and NGL prices further buoying the Company's netbacks. As the majority of Storm's condensate and NGL revenue streams are priced with reference to crude oil, the significantly improved fundamentals in the crude oil market help to differentiate Storm's business plan, particularly in light of the ability to focus drilling on areas with higher liquids.

In the first quarter of 2018, Storm's Boe-per-day production grew by 16% year over year and by 10% when compared to the immediately preceding quarter. The increase in production was a result of increased firm transportation commitments to the Chicago market that came into effect in December 2017 coupled with supportive natural gas prices during the quarter in both the Chicago market and at Station 2. The additional compression to twin the third field compression facility was purchased and moved to site during the first quarter at a cost of $5 million with a further $2 million required for installation, the result of which will increase total field compression capacity to 150 Mmcf per day. Storm's current production is approximately 20,000 Boe per day based on field estimates and increasing production beyond approximately 21,000 Boe per day requires the aforementioned twinning of the third field compression facility, currently dependent on natural gas prices at Station 2. Once completed this will support growth to approximately 27,000 Boe per day.

Field operating netback and funds flow per Boe for the first quarter of 2018 amounted to $16.52 and $13.27, respectively, an increase from $15.88 and $11.76 from the same period in 2017. The increases in the field operating netback and funds flow per Boe from the comparative period were primarily due to higher realized condensate and NGL prices, a lower realized loss on hedging and lower production costs. Higher crude oil pricing in the first quarter of 2018 was the main driver of the realized loss on commodity price contracts, reducing per-Boe funds flow by $1.19 in the quarter. It should be recognized that the netback measurements do not reflect supply cost. The best proxy for such a number would be the most recent measurement of finding and development cost for proved developed producing reserves ("PDP"), which for Storm amounted to $5.76 per Boe for the year ended December 31, 2017. Using Storm's first quarter funds flow of $13.27 per Boe results in a PDP recycle ratio of approximately 2.3 times, a further improvement relative to the recycle ratio of 1.9 times achieved in the year ended December 31, 2017.

Capital expenditures for the first quarter of 2018 totaled $22.9 million and included $8.9 million for the completion of three wells at Nig plus $12.8 million for facilities, equipping and pipelines. During the quarter no wells were drilled and two wells were brought on stream. At quarter end the Company had an inventory of 10 standing wells, of which seven awaited completion, with the remaining three wells completed and tied in but not yet producing. Based on the current capital program, three wells will be drilled in the second half of the year, and an additional eight wells will be completed over the remainder of the year. Based on this level of activity, fourth quarter production is forecast to be 20,000 to 21,000 Boe per day. Capital expenditures in the first quarter came in just under funds flow, with this outlay representing approximately 40% of the total capital budget for 2018 (assuming the low end of guidance). It is anticipated that for the remainder of the year planned capital expenditures will be less than funds flow with the free cash flow to be used to reduce outstanding debt.

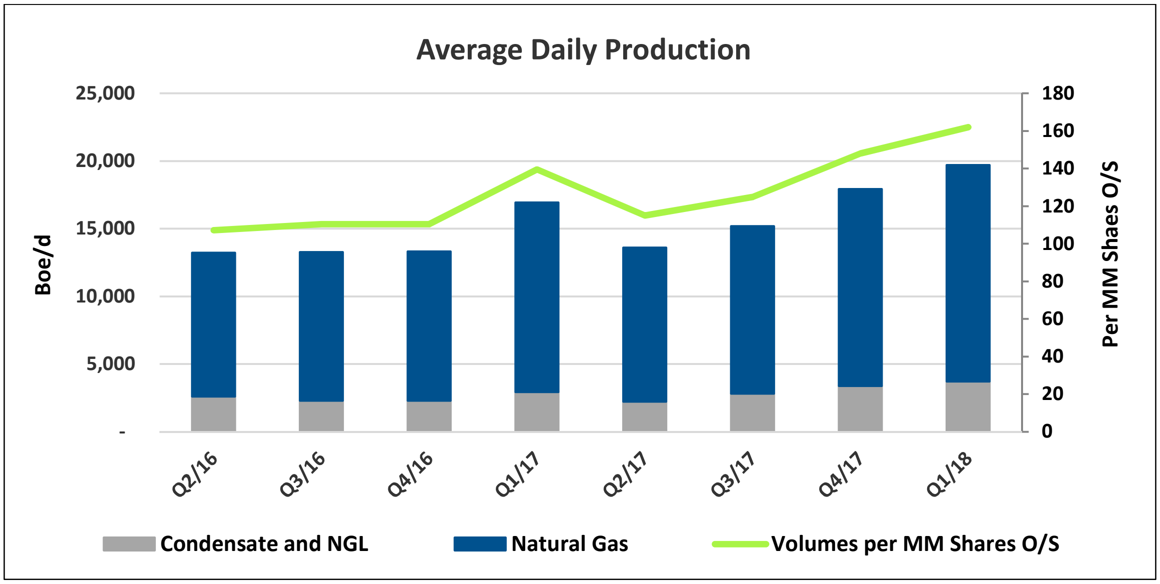
Subsequent to quarter end, the Company's credit facility was increased by $15 million to $180 million, an increase of 9%. The credit facility is predominantly based on the banking syndicate's assessment of the value of the Company's PDP reserves as collateral. Despite a challenging outlook for natural gas prices in the short term, the credit facility increase was supported by the increase in PDP reserves, which grew by 33% year over year, while the net present value of PDP reserves (before tax, 10%) increased by 23% based on InSite Petroleum Consultants Ltd. December 31, 2017 commodity price deck. While the revised credit facility provides increased financial flexibility, it will have no effect on the Company's capital or operating programs at this time. No additional covenants were required and there were minor adjustments made to the interest rate structure, which is expected to result in slightly lower borrowing costs on a go-forward basis.

Production and Revenue

Average Daily Production

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Natural gas (Mcf/d)	96,068	84,093	87,375
Condensate (Bbls/d)	2,062	1,758	1,914
NGL (Bbls/d)	1,635	1,174	1,460
Total (Boe/d)	19,708	16,947	17,936
Natural gas weighting	81%	83%	81%
Condensate weighting	11%	10%	11%
NGL weighting	8%	7%	8%

Production increases for natural gas, condensate and NGL for the first quarter of 2018, when compared to the first quarter of 2017 and the fourth quarter of 2017, came from growth at Umbach where the Company started production from two new 100% working interest horizontal wells during the first quarter of 2018.



Storm's first quarter 2018 production increased 16% from the first quarter of 2017 and increased 10% from the fourth quarter of 2017. However, as a result of ongoing weakness in Western Canadian natural gas prices, production was not maximized and was maintained at a level to meet firm processing and transportation commitments.

Daily production per million shares outstanding at the end of the first quarter averaged 162 Boe per day, compared to 139 Boe per day for the first quarter of 2017, an increase of 16%, and 148 Boe per day for the fourth quarter of 2017, an increase of 10%.

Average Selling Prices(1)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Natural gas – Mcf	$ 3.83	$ 4.20	$ 3.34
Condensate – Bbl	$ 76.12	$ 64.40	$ 69.53
NGL - Bbl	$ 33.05	$ 23.09	$ 33.29
Per Boe	$ 29.37	$ 29.10	$ 26.37

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

On a per-Boe basis, the Company's average realized price for the first quarter of 2018 was in line with the same period in 2017, as increases in condensate and NGL pricing were almost completely offset by a decrease in the realized natural gas price.

On a per-Boe basis, the Company's average realized price for the first quarter of 2018 increased by 11% when compared to the fourth quarter of 2017, primarily driven by higher realized natural gas and condensate prices.

Benchmark Prices

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Natural gas			
Chicago monthly index (US$/Mmbtu)	3.27	3.40	2.92
Chicago daily index (US$/Mmbtu)	2.95	2.98	2.83
Sumas (US$/Mmbtu)	2.46	2.83	2.67
AECO monthly index (Cdn$/GJ)	1.76	2.79	1.85
AECO daily index (Cdn$/GJ)	1.97	2.55	1.60
Station 2 (Cdn$/GJ)	1.81	2.36	0.53

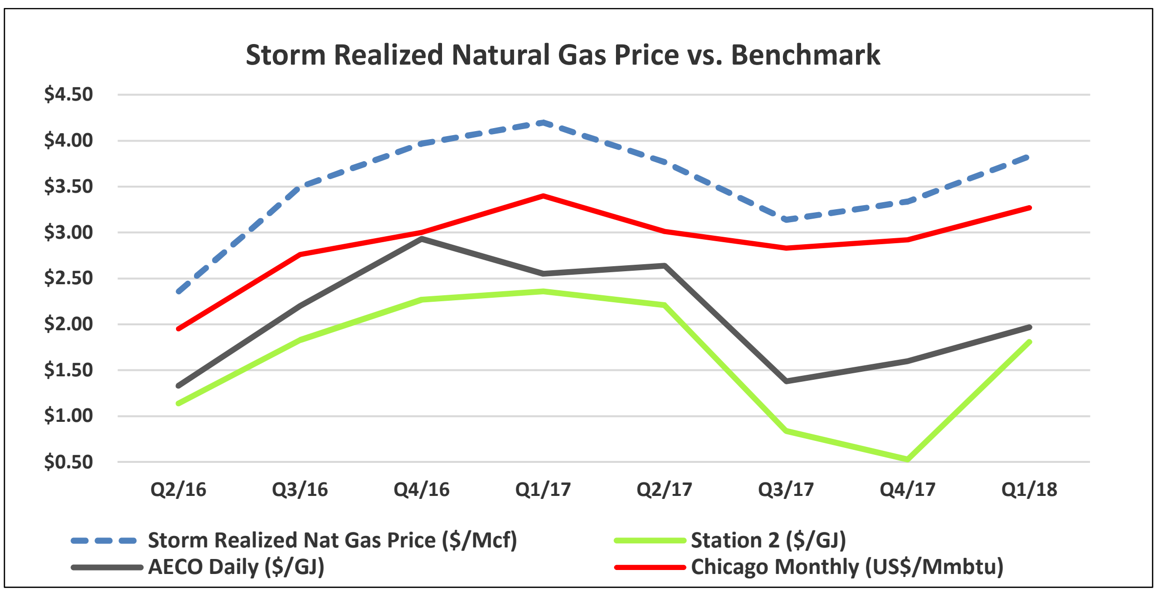
	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Crude Oil			
WTI (US$/Bbl)	62.87	51.91	55.40
Edmonton light oil (Cdn$/Bbl)	72.08	63.99	69.02
Exchange rate (US$/Cdn$)	0.79	0.76	0.79

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

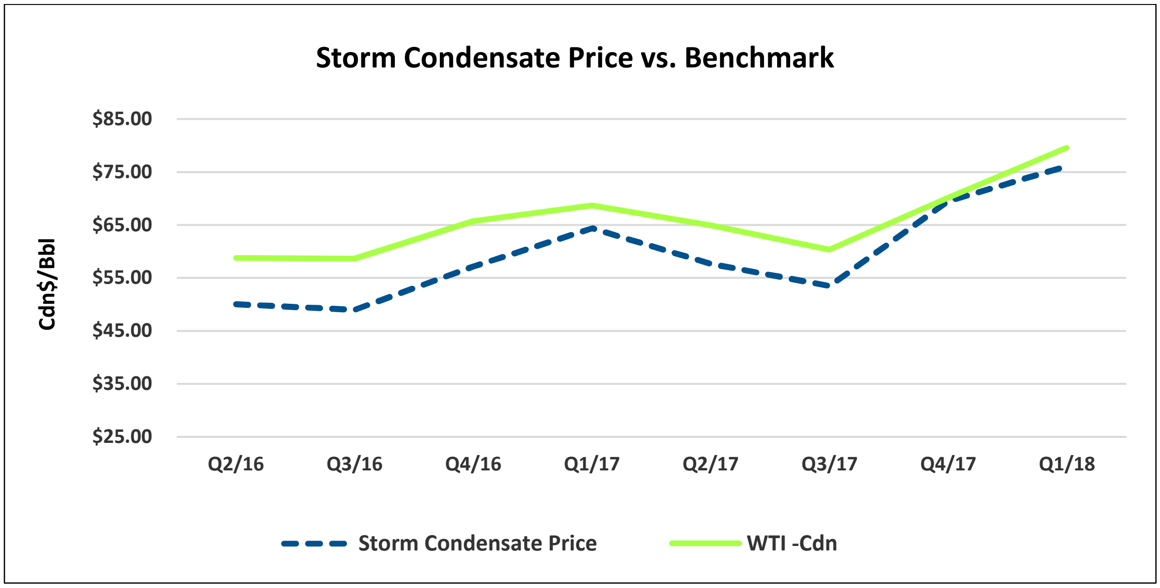
During the summer of 2017, AECO and Station 2 prices fell considerably and remained weak for the remainder of 2017 due to a combination of factors on the TransCanada Pipelines Limited ("TCPL") NGTL and Enbridge (Spectra) pipeline systems. The most notable were a change in the methodology by which TCPL restricts gas flows during maintenance and continued robust supply growth from the Western Canadian Sedimentary Basin leading to production levels hitting a high for the year in December 2017. With supply levels remaining elevated through the first quarter and the 2018 maintenance season underway, Western Canadian natural gas prices are expected to remain volatile for the foreseeable future.

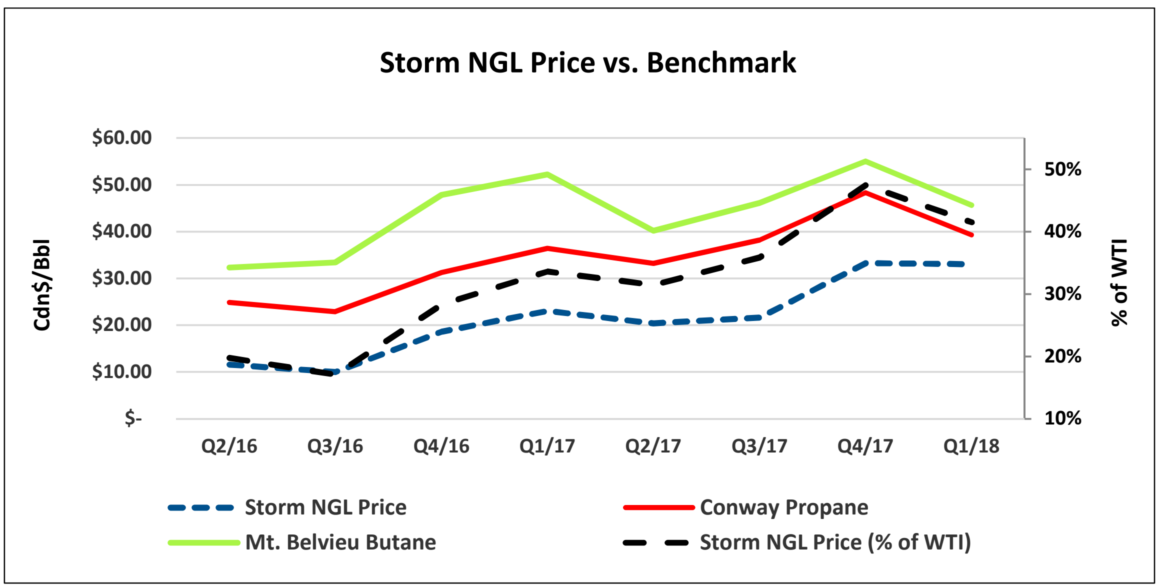
The Company's production during the first quarter was sold as follows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Chicago monthly index price	41%	48%	45%
Chicago daily index price	23%	14%	25%
Station 2 daily spot price	17%	32%	24%
Sumas index price	13%	-	-
Alliance Transfer Point ("ATP")	6%	6%	6%
Total	100%	100%	100%



Storm's realized natural gas price for the first quarter of 2018 was $3.83 per Mcf. With 64% of the Company's production sold in Chicago, Storm's basket realized natural gas price benefited from stronger Chicago pricing, which was partially offset by lower Station 2 pricing. As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was over 100% higher than Station 2 pricing in the first quarter of 2018. Despite a significant improvement in Station 2 pricing in the first quarter of 2018 compared to the preceding quarter, Station 2 pricing remains below the cost of replacing production for most producers.





Storm's liquids stream in the first quarter of 2018 contained approximately 56% condensate, which is generally priced with reference to benchmark pricing for Edmonton light oil. Storm received an average price of $76.12 per barrel for condensate, an 18% increase from the price realized in the same period of 2017. In the first quarter of 2018, WTI averaged US$62.87 per barrel and Edmonton light oil was Cdn$72.08 per barrel, resulting in a US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$7.50 per barrel, compared to Cdn$4.31 per barrel in the same period of 2017. The realized price for NGL, excluding condensate, in the first quarter of 2018 increased by 43% relative to the same period of 2017. The increase in realized NGL prices was primarily due to a material recovery in propane pricing year over year.

Increasing natural gas production has resulted in higher value condensate becoming a significant contributor to revenue. The contribution from this revenue stream comprised 11% of Boe production but amounted to 27% of revenue from product sales in the first quarter of 2018.

Revenue from Product Sales(1)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Natural gas	$ 33,113	$ 31,764	$ 26,792
Condensate	14,127	10,189	12,243
NGL	4,862	2,439	4,471
Total	$ 52,102	$ 44,392	$ 43,506
% of Total Revenue by Product Type			
Natural gas	64%	72%	62%
Condensate and NGL	36%	28%	38%
Total	100%	100%	100%

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

Revenue from product sales for the first quarter of 2018 increased by 17% when compared to the first quarter of 2017 primarily as a result of production volumes increasing by 16% and increases in per-Boe pricing for both condensate and NGL, which was partially offset by a lower realized natural gas price. Compared to the prior quarter, the increase in revenue from product sales was predominantly due to an improvement in natural gas and condensate pricing and a 10% increase in production volumes.

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q1 2017	$ 31,764	$ 10,189	$ 2,439	$ 44,392
Effect of changes in production	4,549	1,763	958	7,270
Effect of changes in average product prices	(3,200)	2,175	1,465	440
Revenue from product sales – Q1 2018	$ 33,113	$ 14,127	$ 4,862	$ 52,102

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q4 2017	$ 26,792	$ 12,243	$ 4,471	$ 43,506
Effect of changes in production	2,086	662	428	3,176
Effect of changes in average product prices	4,235	1,222	(37)	5,420
Revenue from product sales – Q1 2018	$ 33,113	$ 14,127	$ 4,862	$ 52,102

Commodity Price Risk Management

	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017		Three Months Ended December 31, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (483)	$ (620)	$ (3,422)	$ 13,752	$ 1,014	$ 3,744
Liquids(1)	(1,636)	(1,478)	(96)	2,373	(329)	(4,551)
Gain (loss) on commodity price contracts	$ (2,119)	$ (2,098)	$ (3,518)	$ 16,125	$ 685	$ (807)

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

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

The realized gain (loss) on commodity price contracts consists of the portion of contracts that have settled in cash during the reporting period.

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

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

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Apr – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Apr – Dec 2018	11,500 Mmbtu	Chicago Cdn$3.65/Mmbtu
Apr – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.01/Mmbtu
Jul – Dec 2018	31,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jan – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jan – Dec 2019	13,000 Mmbtu	Chicago Cdn$3.17/Mmbtu
Natural Gas Differential Swaps		
Apr – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Jan – Dec 2020	10,000 Mmbtu	Price at Chicago = NYMEX minus US$0.27/Mmbtu
Jan – Dec 2021	5,000 Mmbtu	Price at Chicago = NYMEX minus US$0.26/Mmbtu
Crude Oil Collars		
Apr – Jun 2018	250 Bbls	$66.40 - $72.20 Cdn$/Bbl
Apr – Dec 2018	450 Bbls	$62.78 - $71.67 Cdn$/Bbl
Jul – Dec 2018	350 Bbls	$73.57 - $85.56 Cdn$/Bbl
Jan – Jun 2019	550 Bbls	$67.71 - $78.33 Cdn$/Bbl
Jul – Dec 2019	200 Bbls	$69.00 - $78.00 Cdn$/Bbl
Jan – Dec 2019	100 Bbls	$68.00 - $75.50 Cdn$/Bbl
Crude Oil Swaps		
Apr – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Apr – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	100 Bbls	$71.55 Cdn$/Bbl
Propane Swaps		
Apr – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl

During the first quarter of 2018, the Company realized a loss from commodity price contracts in the amount of $2.1 million compared to a loss of $3.5 million in the first quarter of 2017. The majority of the loss in 2018 related to crude oil contracts as a result of the improvement in crude oil benchmark pricing from the comparative quarter.

The fair market value of contracts outstanding at March 31, 2018 was a net asset position of $0.4 million (March 31, 2017 – net liability of $6.0 million) and is included in current and non-current assets or current and non-current liabilities, as appropriate. For the three months ended March 31, 2018, the change in fair market value resulted in an unrealized mark-to-market loss of $2.1 million (March 31, 2017 – unrealized mark-to-market gain of $16.1 million) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

Physical Delivery Sales Contract

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

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Apr 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Royalties

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period	$ 3,036	$ 2,866	$ 1,046
Percentage of revenue from product sales	5.8%	6.5%	2.4%
Per Boe	$ 1.71	$ 1.88	$ 0.63

Royalties, as a percentage of revenue from product sales, decreased in the first quarter of 2018 from the first quarter of 2017 primarily due to a decrease in commodity prices for natural gas.

Royalties, as a percentage of revenue from product sales, increased in the first quarter of 2018 from the fourth quarter of 2017 due to the receipt of an infrastructure royalty credit in the fourth quarter of 2017 and higher commodity prices in 2018.

The BC Deep Well Royalty Credit Program reduces the royalty rate on new horizontal wells to 6% for approximately two years. In the first quarter of 2018, 36 wells qualified for the 6% royalty rate compared to 27 wells in the first quarter of 2017 and 35 wells in the fourth quarter of 2017.

Storm has remaining infrastructure royalty credits of $6.1 million that will reduce future royalties. Future royalty payments are dependent on commodity prices and production levels from individual wells and thus the timing to receive future royalty credits cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary as these credits are earned.

Production Costs

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period	$ 9,850	$ 8,905	$ 9,376
Per Boe	$ 5.55	$ 5.84	$ 5.68

Total production costs for the first quarter of 2018 increased 11% when compared to the first quarter of 2017 and 5% when compared to the fourth quarter of 2017. The increase in total production costs is due to increased production. The percentage increase in production costs is considerably less than the percentage increase in production volumes, indicative of the Company's efforts to reduce per-Boe costs.

Production costs per Boe for the first quarter of 2018 decreased by 5% when compared to the first quarter of 2017 and by 2% when compared to the fourth quarter of 2017 due to continued production growth.

Transportation Costs

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period	$ 9,912	$ 8,395	$ 9,796
Per Boe	$ 5.59	$ 5.50	$ 5.94

Transportation costs include pipeline tariffs for natural gas sold at various price points, as well as trucking costs for wellhead condensate. Total transportation costs for the first quarter of 2018 increased by 18%, and by 2% per Boe, when compared to the first quarter of 2017. With natural gas and condensate production for the first quarter of 2018 increasing 14% and 17%, respectively, over the first quarter of 2017, higher transportation costs reflect the increased natural gas volumes shipped by pipeline and a higher volume of trucked condensate.

Transportation costs for the first quarter of 2018 were consistent with the fourth quarter of 2017 while per-Boe transportation costs decreased by 6%. The decrease of transportation costs on a per-Boe basis is due to an increase in the proportion of natural gas sold at Station 2 (includes Sumas volumes delivered to Station 2), which has a lower transportation toll relative to the toll on Alliance to Chicago. Storm's diversified marketing strategy provides the Company with the ability to direct incremental volumes to either Station 2 or Chicago, depending on which market provides a more favourable netback.

As a result of the adoption of IFRS 15, *Revenue from Contracts with Customers* on January 1, 2018, transportation costs for the Alliance Pipeline that were previously deducted from revenue to reflect contractual arrangements are now included within transportation costs; comparative periods have been restated to conform to current period presentation.

Field Operating Netbacks

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

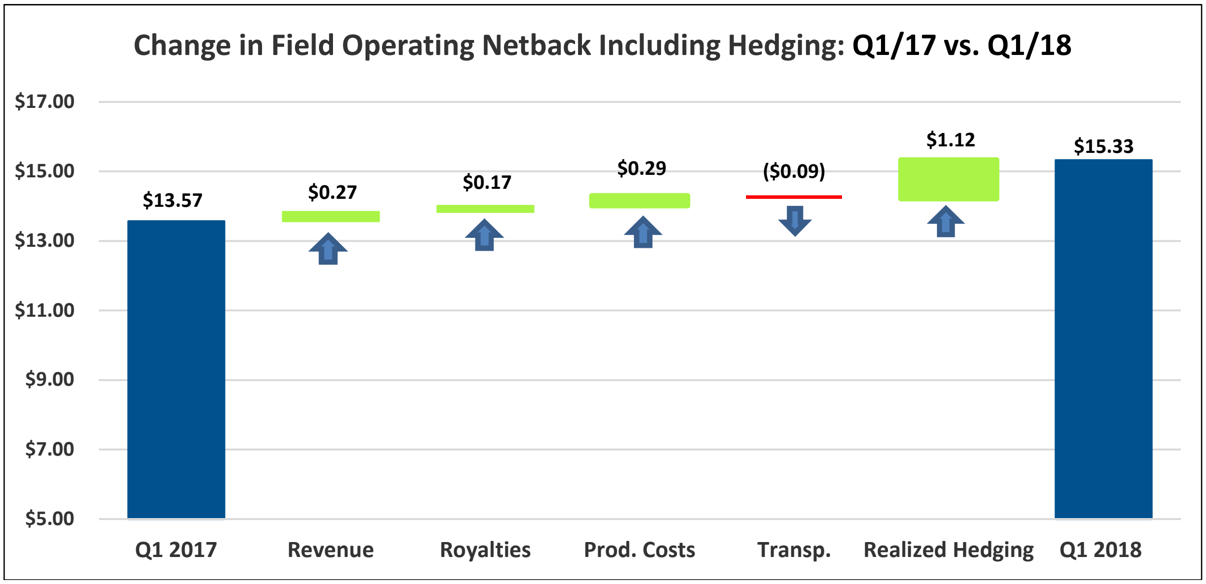
Three Months Ended March 31, 2018	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.83	$ 76.12	$ 33.05	$ 29.37
Royalties	(0.15)	(6.67)	(3.20)	(1.71)
Production costs	(1.14)	-	-	(5.55)
Transportation costs	(1.05)	(4.60)	-	(5.59)
Field operating netback	$ 1.49	$ 64.85	$ 29.85	$ 16.52
Realized (loss) gain on commodity price contracts	(0.06)	(8.84)	0.04	(1.19)
Field operating netback including hedging	$ 1.43	$ 56.01	$ 29.89	$ 15.33

Three Months Ended March 31, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 4.20	$ 64.40	$ 23.09	$ 29.10
Royalties	(0.22)	(5.98)	(2.46)	(1.88)
Production costs	(1.18)	-	-	(5.84)
Transportation costs	(1.05)	(2.72)	-	(5.50)
Field operating netback	$ 1.75	$ 55.70	$ 20.63	$ 15.88
Realized loss on commodity price contracts	(0.45)	(0.61)	-	(2.31)
Field operating netback including hedging	$ 1.30	$ 55.09	$ 20.63	$ 13.57

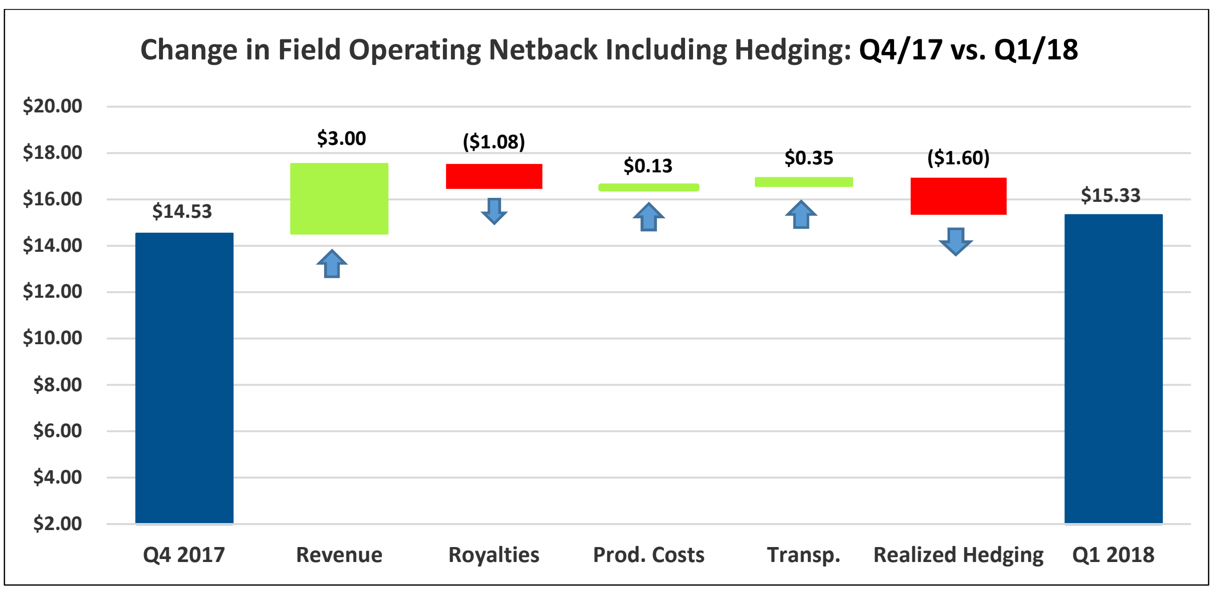
Three Months Ended December 31, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.34	$ 69.53	$ 33.29	$ 26.37
Royalties	0.05	(5.96)	(2.99)	(0.63)
Production costs	(1.17)	-	-	(5.68)
Transportation costs	(1.13)	(4.09)	-	(5.94)
Field operating netback	$ 1.09	$ 59.48	$ 30.30	$ 14.12
Realized (loss) gain on commodity price contracts	0.13	(1.87)	-	0.41
Field operating netback including hedging	$ 1.22	$ 57.61	$ 30.30	$ 14.53

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

The first quarter 2018 field operating netback increased by 4% (13% increase including hedging) compared to the same period in 2017.



The first quarter 2018 field operating netback increased by 17% (6% increase including hedging) compared to the fourth quarter of 2017.



General and Administrative Costs

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period – before recoveries	$ 2,818	$ 2,169	$ 1,879
Overhead recoveries	(294)	(495)	(335)
Charge for period – net of recoveries	$ 2,524	$ 1,674	$ 1,544
Per Boe	$ 1.42	$ 1.10	$ 0.94

General and administrative costs before recoveries for the first quarter of 2018 increased by 30% when compared to the first quarter of 2017 and increased by 50% compared to the fourth quarter of 2017. The increase in general and administrative costs for the first quarter of 2018 relative to the same period in 2017 and the immediately preceding quarter is primarily attributable to the payout of the annual performance bonus after year-end results were finalized. Fluctuations in overhead recoveries are in response to changes in field capital expenditures.

Net general and administrative costs on a per-Boe measure for the first quarter of 2018 increased by 29% compared to the first quarter of 2017, and increased by 51% compared to the fourth quarter of 2017. General and administrative costs for the first and fourth quarters of a fiscal year tend to be higher due to the annual performance bonus payout, if earned, and the inclusion of certain costs specific to year-end reporting. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Interest and Finance Costs

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period	$ 1,142	$ 1,076	$ 1,105
Average interest rate[1]	4.5%	5.1%	4.4%
Per Boe	$ 0.64	$ 0.71	$ 0.67

(1) Includes financing and standby fees.

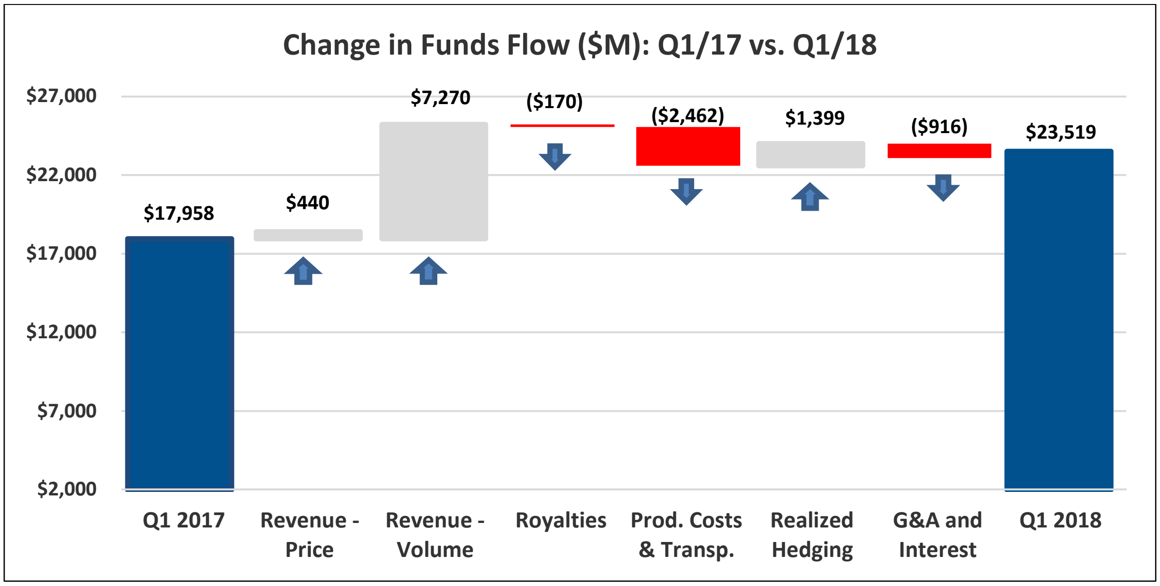
The interest rate on the Company's bank facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the first quarter of 2018 increased by 6% compared to the same quarter of 2017, primarily driven by additional bank borrowings used to fund development of the Company's Umbach property. Interest costs for the first quarter of 2018 were essentially flat compared to the fourth quarter of 2017 as bank borrowings remained relatively unchanged over the two periods.

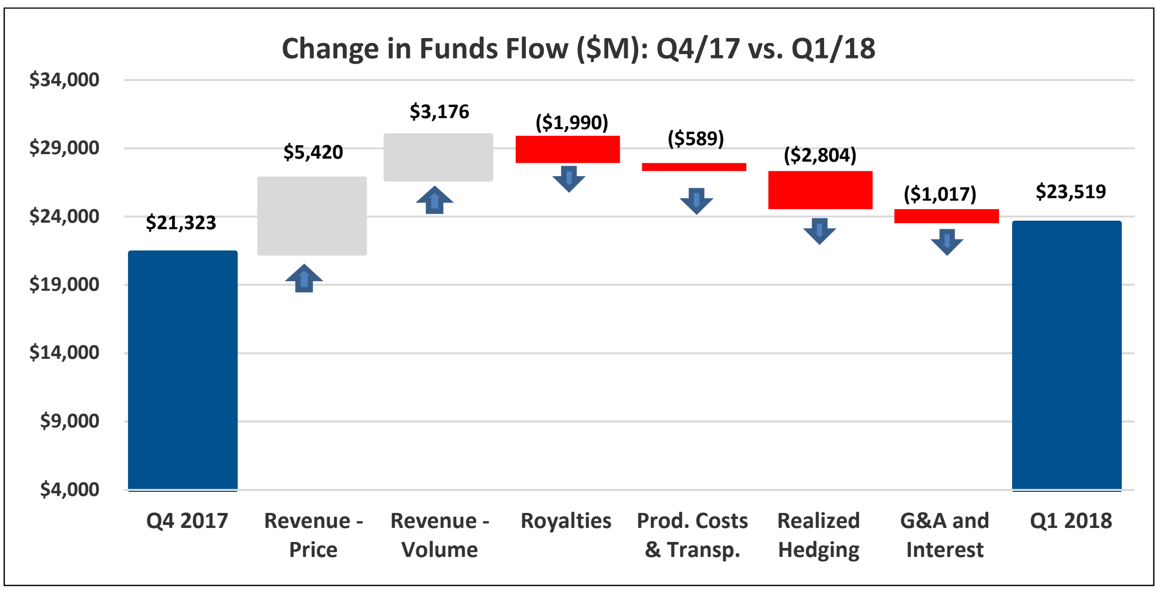
Funds Flow

	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017		Three Months Ended December 31, 2017	
		Per diluted share		Per diluted share		Per diluted share
Funds flow	$ 23,519	$ 0.19	$ 17,958	$ 0.15	$ 21,323	$ 0.18

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



Production growth and a lower realized hedging loss were the predominant factors in funds flow growth of 31% in the first quarter of 2018 versus the first quarter of 2017.



Funds flow for the first quarter of 2018 increased by 10% from the fourth quarter of 2017. Funds flow benefited from both production growth and stronger realized pricing relative to the fourth quarter of 2017.

Share-Based Compensation

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Charge for period	$ 694	$ 954	$ 902
Per Boe	$ 0.39	$ 0.63	$ 0.55

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 27% in the first quarter of 2018 compared to the same quarter of 2017 and decreased by 23% when compared to the immediately prior quarter. The decrease in share-based compensation is primarily attributable to a lower option valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Depletion	$ 9,835	$ 10,614	$ 9,285
Depreciation	1,612	1,404	1,541
Charge for period	$ 11,447	$ 12,018	$ 10,826
Per Boe	$ 6.45	$ 7.88	$ 6.56

Depletion and depreciation decreased by 5% in the first quarter of 2018 compared to the same quarter of 2017 due to lower finding and development costs that more than offset a 16% increase in production volumes. Comparing the first quarter of 2018 with the fourth quarter of 2017, production volumes grew by 10% with the depletion and depreciation charge increasing by 6%. The quarterly and year-to-date per-Boe decreases in depletion correspond to lower finding and development costs at Umbach.

Income Taxes

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

Tax Pools	As at March 31, 2018	Maximum Annual Deduction
Canadian oil and gas property expense	$ 47,000	10%
Canadian development expense	126,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	86,000	20 - 100%
Operating losses	196,000	100%
Other	1,000	20 - 100%
Total	$ 479,000	

Net Income

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Net income	$ 8,894	$ 20,631	$ 8,624
Per basic and diluted share	$ 0.07	$ 0.17	$ 0.07

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion on reported net income for the first quarter of 2018 relative to the same period in 2017. For the first quarter of 2018, the unrealized loss on commodity price contracts amounted to $2.1 million compared to an unrealized gain in the first quarter of 2017 of $16.1 million and an unrealized loss of $0.8 million in the fourth quarter of 2017.

Excluding unrealized gains and losses on commodity price contracts, the increase in net income in the first quarter of 2018 compared to the same period in 2017 is primarily attributable to increased production levels driving increased revenue.

Corporate Netbacks

($/Boe)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Revenue from product sales	29.37	29.10	26.37
Realized gain (loss) on commodity price contracts	(1.19)	(2.31)	0.41
Royalties	(1.71)	(1.88)	(0.63)
Production	(5.55)	(5.84)	(5.68)
Transportation	(5.59)	(5.50)	(5.94)
General and administrative	(1.42)	(1.10)	(0.94)
Interest and finance costs	(0.64)	(0.71)	(0.67)
Funds flow	13.27	11.76	12.92
Share-based compensation	(0.39)	(0.63)	(0.55)
Depletion, depreciation and accretion	(6.52)	(7.95)	(6.64)
Exploration and evaluation costs expensed	(0.10)	(0.20)	(0.01)
Unrealized revaluation loss on investments	(0.05)	(0.05)	(0.01)
Unrealized gain (loss) on commodity price contracts	(1.18)	10.57	(0.49)
Net income	5.03	13.50	5.22

INVESTMENT AND FINANCING

Financial Resources and Liquidity

Subsequent to March 31, 2018, the Company's credit facility was increased to $180 million from $165 million in recognition of production and reserve growth at Umbach. The credit facility is available until April 26, 2019 at which time the borrowing base amount will be reviewed using independently evaluated reserve information. In the ordinary course of business, the Company has the option to extend the credit facility for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The credit facility is syndicated with three banks.

At March 31, 2018, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the credit facility limit. At March 31, 2018, debt including working capital deficiency amounted to $105.6 million, representing 67% of the available credit facility.

In quarters of high field activity, Storm operates with a working capital deficit, which will be reduced in quarters of lower field activity. The Company's capital expenditure budget is set by management at the beginning of the calendar year and approved by the Board of Directors. It is updated regularly with changes subject to approval by the Board of Directors. Management is accountable to the Board of Directors for the execution of the business plan represented by the budget and updates the Board on progress at least four times a year.

Capital Expenditures

In the first quarter of 2018, the Company spent $22.9 million (first quarter of 2017 - $27.4 million) on field operations, primarily on completing three horizontal wells at Nig, building a pipeline to tie in the Nig wells, and purchasing additional compression to twin the Company's third compression facility.

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Land and seismic	$ 574	$ 256	$ 765
Drilling	-	9,879	13,329
Completions	8,884	9,103	8,055
Facilities	5,339	1,682	858
Equipping and pipelines	7,443	5,635	2,943
Recompletions and workovers	653	802	172
Property acquisition and administrative assets	7	-	4
Total capital expenditures	$ 22,900	$ 27,357	$ 26,126

Net capital investment was allocated as follows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended December 31, 2017
Exploration and evaluation	$ 574	$ 250	$ 765
Property and equipment	22,326	27,107	25,361
Total capital expenditures	$ 22,900	$ 27,357	$ 26,126

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 March 31, 2018 corresponds to the active field program at Umbach.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at March 31, 2018 was $36.8 million (December 31, 2017 - $36.3 million) and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, and (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value was 2.25% (December 31, 2017 – 2.20%). Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources and with reference to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to March 31, 2018 are as follows:

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

		Number of Shares (000s)	Price per Share	Gross Proceeds[(1)] ($000s)
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended Dec.31/15	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Year ended Dec.31/16	Stock option exercises	1,297	$ 1.97	2,558
Year ended Dec.31/17	Stock option exercises	793	$ 1.83	1,456
Total at March 31, 2018		121,557	$ 3.26	$ 395,930

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

There were no stock options exercised during the first quarter of 2018. Issued and outstanding common shares at March 31, 2018 and at May 15, 2018, the date of this MD&A, totaled 121,556,812.

CONTRACTUAL OBLIGATIONS

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

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

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At March 31, 2018, the remaining office lease commitment is $0.5 million. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years. In addition, as at the date of this report, the Company has natural gas transportation and processing commitments valued at a total of approximately $372.5 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended March 31, 2018 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results from the second quarter of 2016 reflect the relentless fall in commodity prices in the period resulting in a reduction to capital investment and a flat production profile. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to implement a larger capital expenditure program in the fourth quarter of 2016 which increased production in the first quarter of 2017 as new wells were turned on.

The second and third quarters of 2017 saw a retreat in pricing for natural gas and condensate and a reduction in production due to a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow. With road bans in place for the better part of the second quarter of 2017, capital expenditures were limited as no wells were drilled or completed during the quarter. As road bans were lifted, the third quarter saw a return to normal field activity levels with three wells drilled and five wells completed. However, low natural gas prices in the third quarter of 2017 resulted in production being managed to the level required to meet firm processing and transportation commitments.

Despite a decrease of 37% in Station 2 pricing in the fourth quarter of 2017 compared to the preceding quarter, Storm's realized price increased 23% to $26.37 per Boe, primarily due to an increase in liquids pricing. Production volumes increased 18% compared to the preceding quarter, which contributed to higher revenue and funds flow in the fourth quarter of 2017.

In the first quarter of 2018, Storm benefited from an increase in realized pricing due to stronger natural gas and condensate prices coupled with higher production volumes supported by additional firm transportation to the Chicago market that came into effect in December 2017. Most notably, benchmark pricing for Station 2 increased 242% when comparing the first quarter of 2018 to the preceding quarter. This resulted in yet another period of strong funds flow generation that was in excess of net capital expenditures, leading to a modest reduction in debt levels relative to the prior period.

	2018				2017			2016
($000s unless otherwise stated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue from product sales	52,102	43,506	31,719	33,262	44,392	32,976	27,656	20,138
Funds flow	23,519	21,323	13,170	11,629	17,958	11,985	8,759	5,781
Per share – basic and diluted ($)	0.19	0.18	0.11	0.10	0.15	0.10	0.07	0.05
Net income (loss)	8,894	8,624	682	9,752	20,631	(12,898)	(85)	(20,493)
Per share – basic and diluted ($)	0.07	0.07	0.01	0.08	0.17	(0.11)	(0.00)	(0.17)
Net capital expenditures	22,900	26,126	23,895	4,307	27,357	33,399	6,980	613
Average daily production (Boe)	19,708	17,936	15,193	13,991	16,947	13,320	13,285	12,852
Debt including working capital deficiency(1)	105,585	106,124	101,297	90,582	97,864	89,841	69,303	71,254

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

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended March 31, 2018 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary; further, it may change between reporting periods. Variations between amounts estimated and actual results could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

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

Accounts Receivable, Accounts Payable and Accrued Liabilities

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

Commodity Price Contracts

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

Exploration and Evaluation Assets

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

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management, and the estimates used could differ from similar estimates developed by other parties. In addition, acquired property and equipment is initially recorded at fair value as determined by management. Measurement of fair value includes estimation and judgment and is inherently subjective and uncertain. Property and equipment is subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made.

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

Decommissioning Liability

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

Share-Based Compensation

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

Income Taxes

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

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's May 15, 2018 press release, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold including prices as outlined in 2018 guidance;
- future average production volumes in the fourth quarter of 2018 and annual production for 2018, production growth of 25% in 2018, along with production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2018 guidance;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2018 capital expenditure program including 2018 capital of $55 million to $65 million;
- second quarter of 2018 production and capital investment of 19,500 to 20,500 Boe per day and $6.0 million, respectively, along with capital investment being less than funds flow for the second quarter of 2018 leading to debt reduction of approximately $15 million;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including the amounts outlined in 2018 guidance and per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities including approximately $58 million of unused credit capacity at quarter end;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells including improvements on future wells from drilling longer wells leading to both achievement and outperformance of the 7.5 Bcf type curve;

- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2018 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales percentage allocation in 2018 to Chicago, Sumas, Station 2 and AECO markets;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

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

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

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

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

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

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

BUSINESS RISKS

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. Information with respect to such risks is set out in Storm's Annual Information Form dated March 29, 2018 for the year ended December 31, 2017 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2017 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company retrospectively adopted IFRS 9 *Financial Instruments*, which replaces IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected credit loss" impairment method and a substantially reformed approach to hedge accounting. Prior to the adoption of IFRS 9, the Company did not apply hedge accounting to its commodity price contracts and there was no change to this approach with adoption of IFRS 9. IFRS 9 contains three principal categories for financial assets: measured at amortized cost, fair value through other comprehensive income and fair value through profit and loss. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. The adoption of IFRS 9 resulted in a change in classification of the Company's financial assets, which primarily consist of accounts receivable and commodity price contracts. The expected credit loss model applies to the Company's accounts receivable. As at March 31, 2018, 100% of the Company's accounts receivable was outstanding for less than 60 days. Based on an analysis of historic credit losses, the average expected credit loss applied to accounts receivable did not result in a material adjustment. Prior to the adoption of IFRS 9, the Company's accounts receivable were classified as loans and receivables and subsequent to the adoption of IFRS 9 will be classified at amortized cost. The Company's commodity price contracts will continue to be classified as fair value through profit and loss. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. The adoption of IFRS 9 did not result in any material change on the valuation of the Company's financial assets.

IFRS 15 Revenue from Contracts with Customers

On January 1, 2018, the Company retrospectively adopted IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts* using the following practical expedients:

- Electing to apply the standard retrospectively only to contracts that were not completed contracts on January 1, 2018; and

- For modified contracts, evaluating the original contracts together with any contract modification at the date of initial application.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 7.

In conjunction with the adoption of IFRS 15, the Company completed a review of the financial statement presentation of its revenue transactions. As a result, certain comparative amounts in the 2017 unaudited interim consolidated financial statements have been reclassified, for comparability purposes, as follows:

	Three Months Ended March 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 37,045	$ 7,347	$ 44,392
Transportation	$ 1,048	$ 7,347	$ 8,395
Net income and comprehensive income for the period	$ 20,631	$ -	$ 20,631

	Three Months Ended December 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 34,844	$ 8,662	$ 43,506
Transportation	$ 1,134	$ 8,662	$ 9,796
Net income and comprehensive income for the period	$ 8,624	$ -	$ 8,624

Future Accounting Policy Changes

A description of additional accounting standards that will be adopted in future periods can be found in Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

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 March 31, 2018 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 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4.

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	March 31, 2018	December 31, 2017
ASSETS		
Current		
Accounts receivable (Note 12)	$ 12,251	$ 15,104
Prepaids and deposits	663	4,542
Fair value of commodity price contracts (Note 12)	2,700	2,842
	15,614	22,488
Fair value of commodity price contracts (Note 12)	73	209
Exploration and evaluation (Note 4)	104,656	103,907
Property and equipment (Note 5)	399,609	388,959
	$ 519,952	$ 515,563
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 19,142	$ 24,777
Fair value of commodity price contracts (Note 12)	2,067	478
	21,209	25,255
Bank indebtedness (Note 6)	99,357	100,993
Fair value of commodity price contracts (Note 12)	331	100
Decommissioning liability (Note 8)	24,726	24,474
	145,623	150,822
Shareholders' equity		
Share capital (Note 9)	391,444	391,444
Contributed surplus (Note 10)	12,708	12,014
Deficit	(29,823)	(38,717)
	374,329	364,741
Commitments (Note 14)		
	$ 519,952	$ 515,563

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

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

(Canadian $000s except per-share amounts) (unaudited)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Revenue		
Revenue from product sales (Note 7)	$ 52,102	$ 44,392
Royalties	(3,036)	(2,866)
Net revenue	49,066	41,526
Realized loss on commodity price contracts (Note 12)	(2,119)	(3,518)
Unrealized gain (loss) on commodity price contracts (Note 12)	(2,098)	16,125
Net revenue and commodity price contracts	44,849	54,133
Expenses		
Production	9,850	8,905
Transportation	9,912	8,395
General and administrative	2,524	1,674
Share-based compensation (Note 10)	694	954
Depletion and depreciation (Note 5)	11,447	12,018
Exploration and evaluation costs expensed (Note 4)	179	298
Accretion (Note 8)	127	102
Interest and finance costs	1,142	1,076
Unrealized revaluation loss on investment	80	80
Total expenses	35,955	33,502
Net income and comprehensive income for the period	$ 8,894	$ 20,631
Net income per share (Note 11)		
- Basic and diluted	$ 0.07	$ 0.17

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)		Three Months Ended March 31, 2018		
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the period	-	-	8,894	8,894
Issue of common shares (Note 9)	-	-	-	-
Share-based compensation (Note 10)	-	694	-	694
Share-based compensation on options exercised (Note 9)	-	-	-	-
Balance, end of period	$ 391,444	$ 12,708	$ (29,823)	$ 374,329

(Canadian $000s) (unaudited)		Three Months Ended March 31, 2017		
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the period	-	-	20,631	20,631
Issue of common shares (Note 9)	1,456	-	-	1,456
Share-based compensation (Note 10)	-	954	-	954
Share-based compensation on options exercised (Note 9)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 9,152	$ (57,775)	$ 342,821

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Operating activities		
Net income for the period	$ 8,894	$ 20,631
Non-cash items:		
Unrealized (gain) loss on commodity price contracts (Note 12)	2,098	(16,125)
Depletion, depreciation and accretion (Notes 5 and 8)	11,574	12,120
Share-based compensation (Note 10)	694	954
Exploration and evaluation costs expensed (Note 4)	179	298
Unrealized revaluation loss on investment	80	80
Funds flow	23,519	17,958
Net change in non-cash working capital items (Note 13)	2,188	353
	25,707	18,311
Financing activities		
Proceeds from issue of common shares (Note 9)	-	1,456
Increase (decrease) in bank indebtedness	(1,636)	11,100
	(1,636)	12,556
Investing activities		
Additions to property and equipment (Note 5)	(22,326)	(27,107)
Additions to exploration and evaluation assets (Note 4)	(574)	(250)
Net change in non-cash working capital items (Note 13)	(1,171)	(3,510)
	(24,071)	(30,867)
Change in cash during the period	-	-
Cash, beginning of period	-	-
Cash, end of period	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three months ended March 31, 2018 and 2017

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

1. REPORTING ENTITY

Storm Resources Ltd. (the "Company" or "Storm"), is an oil and gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX under the symbol "SRX". The Company operates primarily in the province of British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

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

2. BASIS OF PRESENTATION

Statement of Compliance

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"). These financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company's audited financial statements as at and for the years ended December 31, 2017 and 2016. 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 May 15, 2018.

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, 2017.

3. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company retrospectively adopted IFRS 9 *Financial Instruments*, which replaces IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected credit loss" impairment method and a substantially reformed approach to hedge accounting. Prior to the adoption of IFRS 9, the Company did not apply hedge accounting to its commodity price contracts and there was no change to this approach with adoption of IFRS 9. IFRS 9 contains three principal categories for financial assets: measured at amortized cost, fair value through other comprehensive income and fair value through profit and loss. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. The adoption of IFRS 9 resulted in a change in classification of the Company's financial assets, which primarily consist of accounts receivable and commodity price contracts. The expected credit loss model applies to the Company's accounts receivable. As at March 31, 2018, 100% of the Company's accounts receivable was outstanding for less than 60 days. Based on an analysis of historic credit losses, the average expected credit loss applied to accounts receivable did not result in a material adjustment. Prior to the adoption of IFRS 9, the Company's accounts receivable were classified as loans and receivables and subsequent to the adoption of IFRS 9 will be classified at amortized cost. The Company's commodity price contracts will continue to be classified as fair value through profit and loss. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. The adoption of IFRS 9 did not result in any material change to the valuation of the Company's financial assets.

IFRS 15 Revenue from Contracts with Customers

On January 1, 2018, the Company retrospectively adopted IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts* using the following practical expedients:

- Electing to apply the standard retrospectively only to contracts that were not completed contracts on January 1, 2018; and
- For modified contracts, evaluating the original contracts together with any contract modification at the date of initial application.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 7.

In conjunction with the adoption of IFRS 15, the Company completed a review of the financial statement presentation of its revenue transactions. As a result, certain comparative amounts in the 2017 unaudited interim consolidated financial statements have been reclassified, for comparability purposes, as follows:

	Three Months Ended March 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 37,045	$ 7,347	$ 44,392
Transportation	$ 1,048	$ 7,347	$ 8,395
Net income and comprehensive income for the period	$ 20,631	$ -	$ 20,631

Future Accounting Policy Changes

A description of additional accounting standards that will be adopted in future periods can be found in Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

Update to Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are de-recognized when the rights to receive cash flows from the instruments have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial instruments are measured at fair value upon initial recognition. Measurement in subsequent periods is dependent on the financial instrument's classification, as described below:

- *Fair value through profit or loss*
  Financial assets and liabilities designated at fair value through profit or loss are initially recognized and subsequently measured at fair value with subsequent changes in fair value charged to the consolidated statement of income (loss). The Company classifies its commodity price contracts as fair value through profit or loss.

- *Amortized cost*
  Amortized cost and other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest rate method, net of any impairment. The Company includes accounts receivable, accounts payable and accrued liabilities and bank indebtedness within the amortized cost category.

- *Fair value through other comprehensive income*
  Financial assets are measured at fair value with changes in fair value recognized in other comprehensive income (loss), net of tax.

Financial assets and liabilities are offset and the net amount reported in the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Impairment of financial assets

The Company recognizes loss allowances for expected credit losses on its financial assets measured at amortized cost. Loss allowances are measured at an amount equal to the anticipated life of expected credit losses resulting from possible default events over the life of the financial assets.

Commodity price contracts

Commodity price contracts may be used by the Company to manage exposure to market risks related to commodity prices, exchange rates and interest rates. Storm does not use derivative contracts for speculative purposes. The Company does not designate its derivative contracts as hedges and, as such, does not apply hedge accounting. All derivative contracts are classified at fair value through profit and loss.

Revenue Recognition

Revenue recognition from the sale of commodities is calculated by reference to consideration specified in contracts with customers and recognized when control of the product is transferred to the buyer. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the delivery mechanism agreed with the customer, often pipelines or other transportation methods.

The Company sells its production pursuant primarily to variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors depending on the contract terms. Under its contracts, the Company is required to deliver volumes of natural gas, condensate and NGL to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to fluctuations in commodity prices. Natural gas, condensate and NGL are mostly sold under contracts of varying price and volume terms. Revenues are typically collected on the 25th day of the month following production.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

4. EXPLORATION AND EVALUATION

	Three Months Ended March 31, 2018	Year ended December 31, 2017
Balance, beginning of period	$ 103,907	$ 110,395
Additions	574	1,838
Expiries - exploration and evaluation costs expensed	(179)	(386)
Future decommissioning costs	354	192
Disposals	-	-
Transfer to property and equipment	-	(8,132)
Balance, end of period	$ 104,656	$ 103,907

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at March 31, 2018 and none were identified.

5. PROPERTY AND EQUIPMENT

	Three Months Ended March 31, 2018	Year ended December 31, 2017
Cost		
Balance, beginning of period	$ 559,524	$ 466,700
Additions	22,326	79,847
Future decommissioning costs	(229)	4,845
Disposals	-	-
Transfer from exploration and evaluation assets	-	8,132
Balance, end of period	$ 581,621	$ 559,524
Accumulated depletion and depreciation		
Balance, beginning of period	$ (170,565)	$ (126,336)
Depletion and depreciation	(11,447)	(44,229)
Balance, end of period	$ (182,012)	$ (170,565)
Net book value, beginning of period	$ 388,959	$ 340,364
Net book value, end of period	$ 399,609	$ 388,959

Management reviewed the carrying amounts of property and equipment for indicators of impairment at March 31, 2018 and none were identified.

6. BANK INDEBTEDNESS

As at March 31, 2018, the Company had an extendible revolving credit facility in the amount of $165 million (December 31, 2017 – $165 million) based on a bank determined borrowing base related to the Company's producing reserves. At March 31, 2018, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount.

As at March 31, 2018, the Company had issued letters of credit in the amount of $7.4 million (December 31, 2017 - $7.3 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

Subsequent to March 31, 2018, the Company's bank syndicate completed the annual borrowing base review with the result being that the Company's credit facility was increased to $180 million. No additional covenants were imposed.

The credit facility is available to the Company until April 26, 2019, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one year later. Interest is paid on the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company.

7. REVENUE FROM PRODUCT SALES

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Natural gas	$ 33,113	$ 31,764
Condensate	14,127	10,189
NGL	4,862	2,439
Total	$ 52,102	$ 44,392

Storm's revenue was generated primarily in British Columbia where the production was sold primarily to one major marketer, which accounted for 44% of the Company's total revenue from product sales. The majority of revenues are derived from variable price contracts based on index prices. Of total natural gas revenue for the three months ended March 31, 2018, 64% received Chicago index based pricing, 17% received Station 2 pricing, 13% received Sumas pricing and the remaining 6% received ATP pricing.

8. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning obligation is approximately $36.8 million (December 31, 2017 - $36.3 million), with the majority of payments being made in the years 2034 to 2054. A risk-free discount rate of 2.25% (December 31, 2017 – 2.2%) and an inflation rate of 2.0% (December 31, 2017 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $24.7 million at March 31, 2018.

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

	Three Months Ended March 31, 2018	Year Ended December 31, 2017
Balance, beginning of period	$ 24,474	$ 18,983
Obligations incurred	353	3,028
Obligations disposed	-	-
Change in estimates(1)	(228)	2,009
Accretion expense	127	454
Balance, end of period	$ 24,726	$ 24,474

(1) Relates to changes in inflation rates, risk-free discount 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, 2017	121,557	$ 391,444
Shares issued on stock option exercises	-	-
Balance as at March 31, 2018	121,557	$ 391,444

During the first quarter of 2018 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 March 31, 2018, a total of 12,155,681 common shares were available for issuance. At March 31, 2018 and at May 15, 2018, the date of this quarterly report, options in respect of 8,316,700 common shares were issued and outstanding and options in respect of 3,838,981 common shares are available for future issue.

Details of the options outstanding at March 31, 2018 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2017	7,914	$ 4.46
Granted during the period	2,395	$ 2.86
Forfeited during the period	(399)	$ 4.10
Expired during the period	(1,593)	$ 4.68
Outstanding at March 31, 2018	8,317	$ 3.97
Number exercisable at March 31, 2018	3,729	$ 4.24

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$2.86 - $3.34	2,380	3.8	$ 2.86	-	-
$3.35 - $4.50	3,723	1.3	$ 3.85	2,901	$ 3.93
$4.51 - $5.50	2,214	2.6	$ 5.36	828	$ 5.33
Total	8,317	2.4	$ 3.97	3,729	$ 4.24

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 three months ended March 31, 2018 of $1.03 per share include the following:

	2018
Share price	$2.86
Exercise price	$2.86
Volatility	46%
Forfeiture rate	10%
Expected option life (years)	3.7
Risk-free interest rate	1.8%

Share-based compensation expense of $0.7 million was charged to the consolidated statement of income (loss) during the three months ended March 31, 2018 (2017 - $1.0 million) with an equivalent offset to contributed surplus.

11. NET INCOME PER SHARE

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Net income for the period	$ 8,894	$ 20,631
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of period	121,557	120,764
Effect of shares issued	-	678
Weighted average number of common shares outstanding – basic	121,557	121,442
Dilutive effect of outstanding options(1)	-	278
Weighted average number of common shares outstanding - diluted	121,557	121,720
Net income per share		
Basic and diluted	$ 0.07	$ 0.17

(1) Excludes effect of 9.6 million weighted average common shares related to stock options that were anti-dilutive for the three months ended March 31, 2018 (5.8 million weighted average common shares related to stock options for the three months ended March 31, 2017).

12. FINANCIAL INSTRUMENTS

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

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

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

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three months ended March 31, 2018.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at March 31, 2018:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 10,080	$ (7,380)	$ 2,700
Long-term asset	7,675	(7,602)	73
Current liability	(9,447)	7,380	(2,067)
Long-term liability	(7,933)	7,602	(331)
Net position	$ 375	$ -	$ 375

As at March 31, 2017, the net financial liability and asset recognized in relation to the fair value of commodity price contracts was equal to the gross financial amounts as there were no offsets.

Accounts Receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at March 31, 2018, the Company's most significant marketer accounted for $5.9 million (March 31, 2017 - $6.6 million) of total receivables and 44% (March 31, 2017 – 50%) of total revenues. 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 March 31, 2018, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at March 31, 2018.

The maximum exposure to credit risk at March 31, 2018 was the carrying amount of accounts receivable of $12.3 million and commodity price contract assets of $2.8 million.

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

Commodity Price Contracts

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts at March 31, 2018, a net asset position of $0.4 million (December 31, 2017 – net asset position of $2.5 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the quarter ended March 31, 2018, this resulted in an unrealized mark-to-market loss of $2.1 million (2017 – unrealized mark-to-market gain of $16.1 million) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Apr – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Apr – Dec 2018	11,500 Mmbtu	Chicago Cdn$3.65/Mmbtu
Apr – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.01/Mmbtu
Jul – Dec 2018	31,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jan – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jan – Dec 2019	13,000 Mmbtu	Chicago Cdn$3.17/Mmbtu
Natural Gas Differential Swaps		
Apr – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Jan – Dec 2020	10,000 Mmbtu	Price at Chicago = NYMEX minus US$0.27/Mmbtu
Jan – Dec 2021	5,000 Mmbtu	Price at Chicago = NYMEX minus US$0.26/Mmbtu

Period Hedged	Daily Volume	Average Price
Crude Oil Collars		
Apr – Jun 2018	250 Bbls	$66.40 - $72.20 Cdn$/Bbl
Apr – Dec 2018	450 Bbls	$62.78 - $71.67 Cdn$/Bbl
Jul – Dec 2018	350 Bbls	$73.57 - $85.56 Cdn$/Bbl
Jan – Jun 2019	550 Bbls	$67.71 - $78.33 Cdn$/Bbl
Jul – Dec 2019	200 Bbls	$69.00 - $78.00 Cdn$/Bbl
Jan – Dec 2019	100 Bbls	$68.00 - $75.50 Cdn$/Bbl
Crude Oil Swaps		
Apr – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Apr – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	100 Bbls	$71.55 Cdn$/Bbl
Propane Swaps		
Apr – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl

During the three months ended March 31, 2018, the Company realized a loss from commodity price contracts in place in the amount of $2.1 million (2017 – realized loss of $3.5 million).

Physical Delivery Sales Contract

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

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Apr 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income (loss) due to changes in the fair value of commodity price contracts in place at March 31, 2018. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor		Three Months Ended March 31, 2018
Increase of US$10.00/Bbl in the price of WTI[(1)]	$	(5,167)
Decrease of US$10.00/Bbl in the price of WTI[(1)]	$	5,530
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$	(2,832)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$	2,635

(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 March 31, 2018		Three Months Ended March 31, 2017
Accounts receivable	$	2,773	$	605
Prepaids and deposits		3,879		275
Accounts payable and accrued liabilities		(5,635)		(4,037)
Change in non-cash working capital	$	1,017	$	(3,157)
Relating to:				
Operating activities	$	2,188	$	353
Investing activities		(1,171)		(3,510)
Change in non-cash working capital	$	1,017	$	(3,157)
Interest paid during the period	$	1,127	$	812
Income taxes paid during the period	$	-	$	-

14. COMMITMENTS

At March 31, 2018, the Company has the following long-term commitments over the next five years and thereafter:

	2018	2019	2020	2021	2022	Thereafter	Total
Natural gas transportation and processing commitments	$ 41,627	$ 48,465	$ 31,670	$ 22,281	$ 22,532	$ 205,891	$ 372,466
Office lease	645	796	803	808	816	2,564	6,432
Total	$ 42,272	$ 49,261	$ 32,473	$ 23,089	$ 23,348	$ 208,455	$ 378,898

At present the Company has an office lease for a period of five years that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At March 31, 2018, the remaining commitment with respect to this lease is $0.5 million. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years.

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

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

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Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol "SRX"

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Canadian Imperial Bank of Commerce
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Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or NGL
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bpd	Barrels per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
EIA	U.S. Energy Information Administration
GJ	Gigajoules
GJ/d	Gigajoules per day
HRB	Horn River Basin
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
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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