NEWS RELEASE

May 14, 2019 - CALGARY, ALBERTA - Storm Resources Ltd. (TSX:SRX)

Storm Resources Ltd. ("Storm" or the "Company") is Pleased to Announce Its Financial and Operating Results for the Three Months Ended March 31, 2019

Storm has also filed its unaudited condensed interim consolidated financial statements as at March 31, 2019 and for the three months then ended along with Management's Discussion and Analysis ("MD&A") for the same period. This information appears on SEDAR at www.sedar.com and on Storm's website at www.stormresourcesltd.com.

Selected financial and operating information for the three months ended March 31, 2019 appears below and should be read in conjunction with the related financial statements and MD&A.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
FINANCIAL		
Revenue from product sales(1)	55,766	52,102
Funds flow	16,517	23,519
Per share - basic and diluted ($)	0.14	0.19
Net income	607	8,894
Per share - basic and diluted ($)	0.00	0.07
Cash return on capital employed ("CROCE")(2)	20%	16%
Return on capital employed ("ROCE")(2)	8%	7%
Capital expenditures	16,944	22,900
Debt including working capital deficiency(2)(3)	91,585	105,585
Common shares (000s)		
Weighted average - basic	121,557	121,557
Weighted average - diluted	121,853	121,557
Outstanding end of period – basic	121,557	121,557
OPERATIONS		
(Cdn$ per Boe)		
Revenue from product sales(1)	31.26	29.37
Transportation costs	(5.72)	(5.59)
Revenue net of transportation	25.54	23.78
Royalties	(2.61)	(1.71)
Production costs	(6.09)	(5.55)
Field operating netback(2)	16.84	16.52
Realized loss on commodity price contracts	(5.38)	(1.19)
General and administrative	(1.60)	(1.42)
Interest and finance costs	(0.61)	(0.64)
Funds flow per Boe	9.25	13.27
Barrels of oil equivalent per day (6:1)	19,823	19,708
Natural gas production		
Thousand cubic feet per day	96,537	96,068
Price (Cdn$ per Mcf)(1)	4.49	3.83
Condensate production		
Barrels per day	2,199	2,062
Price (Cdn$ per barrel)(1)	62.77	76.12
NGL production		
Barrels per day	1,534	1,635
Price (Cdn$ per barrel)(1)	31.43	33.05
Wells drilled (net)	5.0	-
Wells completed (net)	-	3.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 25 of the MD&A. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2019 FIRST QUARTER HIGHLIGHTS

An unplanned 17-day outage at the McMahon Gas Plant in January affected both production and funds flow while capital investment was largely equal to funds flow. Horizontal well performance continues to exceed expectations with declines to date shallower than forecast by management's type curve. Regulatory approval for the sour gas plant at Nig was received in April with site construction expected to start in May. In April, the bank credit facility was increased to $205 million.

- Production was largely unchanged year over year and was consistent with revised guidance provided January 15, 2019. The unplanned 17-day outage at the McMahon Gas Plant reduced production in the period by approximately 15%, or 3,700 Boe per day (January was 12,765 Boe per day while February and March was 23,530 Boe per day).

- Liquids production (field condensate plus gas plant NGL) totaled 3,733 barrels per day which was largely unchanged year over year and represented 19% of total production, or 30% of production revenue.

- At the end of the quarter, there was an inventory of ten Montney horizontal wells (9.5 net) that had not started producing which included two completed wells (1.5 net). During the quarter, two wells (2.0 net) started production.

- At the Nig land block, the first three wells have been producing for ten to twelve months with declines being minimal over this period. First year calendar day rates are forecast to average 7.7 Mmcf per day raw gas or approximately 1,400 Boe per day sales with 21% liquids (including liquids recovered at the gas plant).

- Diversified natural gas sales resulted in the realized price averaging $4.49 per Mcf, or $3.43 per Mcf after deducting pipeline transportation costs, which was significantly higher than Western Canadian pricing (Station 2 $1.24 per GJ and AECO $2.49 per GJ). Firm pipeline commitments required to diversify natural gas sales also result in a higher gas transportation cost which was $1.06 per Mcf in the quarter.

- Realized hedging loss increased to $9.6 million from $2.1 million in the prior year with the majority of the increase resulting from the increase in the natural gas price at Sumas after a pipeline failure in October 2018 reduced capacity by approximately 20%. For the quarter, Sumas monthly index averaged Cdn$9.06 per Mmbtu versus the hedged price of Cdn$3.35 per Mmbtu.

- Controllable cash costs, including transportation, production, general and administrative and interest, increased to $14.02 per Boe in the quarter from $13.20 per Boe in the prior year with the increase resulting from the unplanned outage at the McMahon Gas Plant.

- Funds flow was $16.5 million, or $0.14 per share, a decrease of 26% on a per-share basis year over year which was largely the result of a higher hedging loss, lower condensate prices, and costs associated with the unplanned outage at the McMahon Gas Plant which were approximately $5.3 million ($0.6 million from increased production costs, $1.2 million from unused firm pipeline transportation and $3.5 million to purchase natural gas that was pre-sold at a monthly index price).

- Capital investment was $16.9 million which included $11.3 million to drill five horizontal wells (5.0 net), including a four-well pad at Nig and $3.4 million to purchase equipment for the gas plant at Nig.

- The balance sheet remains strong with debt including working capital deficiency being $92 million or 1.4 times annualized quarterly funds flow and is a reduction from $106 million last year.

- Subsequent to quarter end, the bank credit facility was increased to $205 million from $180 million.

- Commodity price hedges currently protect approximately 40% of forecast production for the remainder of 2019.

- Return on capital employed was 8% and cash return on capital employed was 20% on a 12-month trailing basis. Cash return on capital employed is a more meaningful measure of profitability given it is not affected by non-cash mark-to-market gains and losses on hedging (non-cash hedging loss in the first quarter was $4.8 million).

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas, Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and currently totals 121,000 net acres (172 net sections). During the first quarter, five sections of land were acquired.

Most of the land position is delineated with the 78 horizontal wells (73.9 net) drilled to date by Storm and by multiple producing horizontal wells on adjacent lands. The majority of the producing horizontal wells in the area have been drilled in the upper part of the Montney formation. Storm’s future drilling will also test the mid and lower Montney in certain areas where higher field condensate-gas ratios are expected based on offsetting producing wells.

First quarter field activity included drilling four horizontal wells (4.0 net) on one pad at Nig and one horizontal well (1.0 net) at Umbach which was the last well on a three-well pad. Two horizontal wells (2.0 net) started production in the quarter, both at Umbach.

Field activity in the second and third quarters will be focused on the Nig area and is expected to include completion of a four-well pad, drilling and completing an acid gas injection well and starting construction of the sour gas plant. The four-well pad to be completed at Nig includes two wells in the upper Montney, one in the mid and one in the lower.

At Umbach (100% working interest), production in the quarter averaged 15,870 Boe per day with 19% liquids and is currently approximately 17,500 Boe per day. Activity during the remainder of 2019 is expected to include the completion of three horizontal wells (3.0 net) in the fourth quarter. Field compression capacity totals 150 Mmcf per day raw gas and throughput in the first quarter averaged 125 Mmcf per day raw gas excluding the 17-day period where the McMahon Gas Plant was shut in (includes 25 Mmcf per day raw from Nig). Produced raw natural gas is sour (1.2% H_2S) with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant. Firm processing commitments are 65 Mmcf raw gas per day at McMahon (10 Mmcf per day ending 2022, 55 Mmcf per day ending 2031) and 15 Mmcf per day at Stoddart.

At Nig (100% working interest), production in the quarter averaged 3,872 Boe per day with 20% liquids and is currently approximately 4,200 Boe per day. Activity during the remainder of 2019 is expected to include the construction of a 50 Mmcf per day sour gas plant, installing gathering and sales pipelines, drilling and completing an acid gas injection well (1.0 net) and completing and equipping four horizontal wells (4.0 net). In April, regulatory approval was received for the sour gas plant and site construction is expected to start in May with start-up anticipated in early 2020. Produced raw natural gas contains approximately 0.2% H_2S. Total estimated costs associated with the sour gas plant are $81 million (gross) with $11.4 million invested in 2018 and the remainder to be invested in 2019 ($3.4 million to the end of the first quarter). This includes $73 million for the gas plant, $4 million for an acid gas injection well and $4 million for a sales pipeline. Total sales from the gas plant are expected to be 10,500 Boe per day with an estimated operating cost of $2.00 per Boe (reduces corporate operating cost to approximately $4.25 per Boe). Liquids is forecast to be 27% of total production (43% condensate, 57% NGL).

At Fireweed (50% working interest), approximately $15 million (net) will be invested in 2019 to drill and complete three horizontal wells (1.5 net) and for equipment deposits for a field compression facility. Depending on the timing for regulatory approvals, construction is anticipated to begin in late 2019 with start-up in the second half of 2020. Total estimated costs associated with the facility are $34 million (gross) and it is designed to be expandable to 100 Mmcf per day. Preliminary planning for 2020 includes investment of approximately $50 million (net) to drill nine horizontal wells (4.5 net), complete six horizontal wells (3.0 net) and construct the field compression facility. Based on production history from offsetting horizontal wells, first year average field condensate-gas ratios are expected to be 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach. Production exiting 2020 is forecast to be over 4,000 Boe per day net to Storm with 25% liquids (67% condensate, 33% NGL).

The first horizontal well (0.5 net) at Fireweed was completed in the fourth quarter of 2018 with encouraging results. The C-74-G/94-A-13 well has a completed length of 1,520 metres and, after flowing on a six-day cleanup, rates over the last 12 hours averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate and 1,140 barrels per day of frac water with a final flowing casing pressure of 4,800 kPa. The well is expected to remain shut in until the field compression facility is completed.

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not meaningful indicators of performance as wells are initially rate restricted for several months to manage fluid rates. In addition, the 2018 horizontal wells were affected by the 17-day outage at the McMahon Gas Plant in January 2019.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2014 - 2016 33 hz's[1]	22	1350 m	4.9 Mmcf/d[2] 19 Bbls/Mmcf[3] 33 hz's	4.3 Mmcf/d[2] 16 Bbls/Mmcf[3] 33 hz's	3.4 Mmcf/d[2] 13 Bbls/Mmcf[3] 33 hz's
Umbach 2017 12 hz's	34	1830 m	5.0 Mmcf/d[2] 24 Bbls/Mmcf[3] 12 hz's	4.5 Mmcf/d[2] 20 Bbls/Mmcf[3] 12 hz's	4.3 Mmcf/d[2] 14 Bbls/Mmcf[3] 12 hz's
Umbach 2018 7 hz's	35	2005 m	3.9 Mmcf/d[2] 23 Bbls/Mmcf[3] 5 hz's	3.4 Mmcf/d[2 16 Bbls/Mmcf[3] 3 hz's	
Nig 2018 3 hz's	37	2180 m	8.1 Mmcf/d[2] 29 Bbls/Mmcf[3] 3 hz's	8.2 Mmcf/d[2] 25 Bbls/Mmcf[3] 3 hz's	7.8 Mmcf/d[2 24 Bbls/Mmcf[3] 1 hz

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

Based on results from the 2017 and 2018 wells, Storm management is using an 11 Bcf raw gas type curve (internal estimate) to forecast production which represents an average of the expected result at Umbach and Nig. Future wells will be longer (2300 to 2400 metres) and have more fracture stages (41 to 47) which is expected to result in further improvement to rates and reserves. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth with the target being to protect pricing on 50% of current sales in any single market for the next 12 months and 25% for 13 to 24 months forward (future production growth is not hedged). Approximately 80% of Storm's liquids production (condensate and butane) is priced in reference to WTI. The current hedge position protects approximately 40% of forecast production for the remainder of 2019.

Q2 – Q4, 2019	Crude Oil	867 Bpd	WTI Cdn$71.91/Bbl floor, Cdn$85.70/Bbl ceiling
		633 Bpd	WTI Cdn$79.54/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	41,665 Mmbtu/d (35.1 Mmcf/d)	Chicago Cdn$3.26/Mmbtu
		7,830 Mmbtu/d (6.6 Mmcf/d)	Sumas Cdn$2.65/Mmbtu
		335 GJ/d (0.3 Mmcf/d)	AECO Cdn$2.00/GJ
2020	Crude Oil	100 Bpd	WTI Cdn$74.50/Bbl floor, Cdn$86.43/Bbl ceiling
	Natural Gas	10,750 Mmbtu/d (9.1 Mmcf/d)	Chicago Cdn$3.32/Mmbtu
		375 GJ/d (0.3 Mmcf/d)	AECO Cdn$2.00/GJ

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

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

Alliance to Chicago[1]	56 – 70 Mmcf/d
Enbridge T-north to Station 2	16 Mmcf/d
Enbridge T-north & TCPL to AECO	13 Mmcf/d
Enbridge T-north to Station 2/Sumas[2]	12 Mmcf/d
Alliance to ATP	5 Mmcf/d
Total	**102 – 116 Mmcf/d**

(1) When available, Preferential Interruptible Service ('PITS') adds up to 14 Mmcf/d of capacity on the Alliance Pipeline.
(2) Sumas price less US$0.69/Mmbtu.

In the first quarter, 53% of natural gas sales were at a Chicago price, 37% at Western Canadian pricing and 10% at the Sumas price less a marketing adjustment. Production exceeding firm capacity is directed to Chicago and/or Station 2 on an interruptible basis depending on which sales point offers a higher net price.

OUTLOOK

Production in April was approximately 21,800 Boe per day based on field estimates with approximately 2,500 Boe per day shut in as a result of low natural gas prices. Production in the second and third quarters of 2019 is expected to average 20,000 to 22,000 Boe per day which includes the impact of a five-day planned maintenance outage at the McMahon Gas Plant in May and a five-day planned maintenance outage on the Alliance Pipeline in June. As a result of the decline in Western Canadian natural gas prices since the end of the winter heating season (April averaged $0.70 per GJ at Station 2 and $0.80 per GJ at AECO), production has been reduced to the minimum level required to fill firm processing and transportation commitments. Prices are not expected to improve until the winter heating season starts in the fourth quarter given numerous maintenance outages scheduled on the NGTL, Alliance and Spectra T-south pipeline systems that will reduce export capacity between May and August. Capital investment in the second quarter is estimated to be $15 to $20 million with approximately 70% allocated to the sour gas plant at Nig.

The failure on the Enbridge T-south natural gas pipeline system in October 2018 has reduced capacity by approximately 20% which has depressed the Station 2 price in relation to AECO while increasing the price at Sumas. To fully restore capacity, inspections are required on various segments and these are expected to be completed by August 2019, however, additional time will also be required for the National Energy Board to complete its review of the results. Until capacity on the T-south pipeline is restored or until the NGTL North Montney extension into northeast British Columbia is in service (possibly early in the fourth quarter of 2019), the Station 2 price is expected to remain depressed in relation to AECO. The financial impact on Storm has not been material given that firm transportation commitments result in less than 15% of produced natural gas being sold at Station 2.

Updated guidance for 2019 is provided below. Pricing has been updated to reflect actual year-to-date prices with pricing for the remainder of 2019 being unchanged.

2019 Guidance

	Previous February 28, 2019	Current May 14, 2019
Cdn$/US$ exchange rate	0.76	0.76
Chicago daily natural gas - US$/Mmbtu	$2.60	$2.65
Sumas monthly natural gas - US$/Mmbtu	$3.10	$3.40
AECO daily natural gas - Cdn$/GJ	$1.60	$1.65
Station 2 daily natural gas - Cdn$/GJ	$1.25	$1.20
WTI - US$/Bbl	$55.00	$55.00
Edmonton condensate differential - US$/Bbl	-$5.50	-$5.50
Est revenue net of transport (excl hedges) - $/Boe	$17.75 - $18.25	$17.75 - $18.25
Est operating costs - $/Boe	$5.50 - $5.75	$5.50 - $5.75
Est royalty rate (% revenue before hedging)	5% - 7%	5% - 7%
Est mid-point field operating netback - $/Boe	$11.30	$11.30
Est hedging loss - $ million	$7.0 - $8.0	$8.0 - $10.0
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $7.0
- $/Boe	$0.66 - $0.91	$0.66 - $0.91
Est interest expense - $ million	$5.5 - $6.5	$5.5 - $6.5
Est capital investment (excl A&D) - $ million	$128.0	$128.0
Forecast fourth quarter production - Boe/d	23,000 - 25,000	23,000 - 25,000
% liquids	18%	18%

2019 Guidance

	Previous February 28, 2019	Current May 14, 2019
Forecast annual production - Boe/d	21,000 - 24,000	21,000 - 24,000
% liquids	18%	18%
Est annual funds flow - $ million	$67.0 - $79.0(1)	$65.0 - $77.0(1)
Horizontal wells drilled - gross	9 (7.5 net)	9 (7.5 net)
Horizontal wells completed - gross	11 (9.5 net)	11 (9.5 net)
Horizontal wells starting production - gross	9 (9.0 net)	9 (9.0 net)

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

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/bbl)	Estimated Operations Capital ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 13, 2018	$2.50	$1.25	$60.00	$128.0	$72.0 - $88.0	21,000 - 24,000
Feb 28, 2019	$2.60	$1.25	$55.00	$128.0	$67.0 - $79.0	21,000 - 24,000
May 14, 2019	$2.65	$1.20	$55.00	$128.0	$65.0 - $77.0	21,000 - 24,000

With the corporate average decline rate estimated to be 20% in 2019, approximately three new horizontal wells at Nig would be required to offset the decline and maintain 20,000 to 22,000 Boe per day. Wells at Nig are averaging more than 1,400 Boe per day sales in the first year. As a result, at current forward strip commodity prices, funds flow is expected to materially exceed capital investment required to maintain production in 2019.

Capital investment in 2019 remains at $128 million with a significant portion (88%) being directed towards future growth including $70 million for the sour gas plant at Nig, $28 million to drill, complete, and pipeline connect a four-well pad at Nig, and $15 million to advance development at Fireweed. Attractive full-cycle rates of return are expected to be achieved assuming WTI US$55 per barrel, Cdn$/US$ exchange rate 0.76 and Station 2 $1.25 per GJ. Debt including working capital deficiency is forecast to increase by $50 to $60 million by the end of 2019 in order to fund planned growth. This may result in debt including working capital deficiency exceeding the targeted level of 1.0 to 1.5 times annualized funds flow on a short-term basis during construction of the sour gas plant as the full project cost of $81 million must be invested before incremental funds flow is realized. Maintaining a strong balance sheet remains a priority and capital investment and activity are designed to be flexible and can be accelerated or reduced depending on commodity prices.

The near-term plan remains focused on growing funds flow by advancing development of the Nig and Fireweed areas which will be financed using funds flow and available capacity on the bank line. Growth from both areas is expected to reduce per-Boe operating costs while increasing liquids as a proportion of total production with corporate production forecast to increase to approximately 25,000 Boe per day by the end of 2019 (4,600 barrels per day of liquids) and to more than 30,000 Boe per day by the end of 2020 (6,600 barrels per day of liquids). Additional growth from Umbach, where there is under-utilized field compression capacity, is contingent on a higher natural gas price.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 14, 2019

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

Non-GAAP Measures - This document may refer to the terms "debt including working capital deficiency", "field operating netbacks", "field operating netbacks including hedging", "CROCE", "ROCE", the terms "cash" and "non-cash", "cash costs", and measurements "per commodity unit" and "per Boe" which are not recognized under Generally Accepted Accounting Principles ("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, analysts and other parties. Additional information relating to certain of these non-GAAP measures can be found in Storm's MD&A dated May 14, 2019 for the period ended March 31, 2019 which is available on Storm's SEDAR profile at www.sedar.com and on Storm's website at www.stormresourcesltd.com.

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

Forward-Looking Information - This press release contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "will", "would", "expect", "anticipate", "intend", "believe", "plan", "potential", "outlook", "forecast", "estimate", "budget" and similar expressions are intended to identify forward-looking statements or information. More particularly, and without limitation, this press release contains forward-looking statements and information concerning: current and future years' guidance in respect of certain operational and financial metrics, including, but not limited to, commodity pricing, estimated average operating costs, estimated average royalty rate, estimated operations capital, estimated general and administrative costs, estimated quarterly and annual production and estimated number of horizontal wells drilled, completed and connected, capital investment plans, infrastructure plans, anticipated United States exports, pipeline capacity, price volatility mitigation strategy and cost reductions. Statements of "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking statements and information in this press release are based on certain key expectations and assumptions made by Storm, including: prevailing commodity prices and exchange rates; applicable royalty rates and tax laws; future well production rates; reserve and resource volumes; the performance of existing wells; success to be expected in drilling new wells; the adequacy of budgeted capital expenditures to carrying out planned activities; the availability and cost of services; and the receipt, in a timely manner, of regulatory and other required approvals. Although the Company believes that the expectations and assumptions on which such forward-looking statements and information are based are reasonable, undue reliance should not be placed on these forward-looking statements and information because of their inherent uncertainty. In particular, there is no assurance that exploitation of the Company's undeveloped lands and prospects will result in the emergence of profitable operations.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general such as: general economic conditions in Canada, the United States and internationally; operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to reserves, production, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; marketing and transportation of petroleum and natural gas and loss of markets; competition; ability to access sufficient capital from internal and external sources; geopolitical risk; stock market volatility; and changes in legislation, including but not limited to tax laws, royalty rates and environmental regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the operations or financial results of the Company are included or are incorporated by reference in the Company's Annual Information Form dated March 29, 2019 and the MD&A dated May 14, 2019 for the period ended March 31, 2019 which are available on Storm's SEDAR profile at www.sedar.com and on Storm's website at www.stormresourcesltd.com.

The forward-looking statements and information contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

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