NEWS RELEASE

February 28, 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 and Year Ended December 31, 2018

Storm has also filed its audited consolidated financial statements as at December 31, 2018 and for the three months and year then ended along with Management's Discussion and Analysis ("MD&A") for the same periods. 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 and year ended December 31, 2018, as well as reserves information at December 31, 2018, appears below and should be read in conjunction with the related financial statements and MD&A.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
FINANCIAL				
Revenue from product sales[1]	74,799	43,507	226,258	152,880
Funds flow	30,941	21,323	100,092	64,080
Per share – basic and diluted ($)	0.25	0.18	0.82	0.53
Net income	26,810	8,624	40,063	39,689
Per share – basic and diluted ($)	0.22	0.07	0.33	0.33
Cash return on capital employed ("CROCE")[2]	21%	15%	21%	15%
Return on capital employed ("ROCE")[2]	10%	10%	10%	10%
Capital expenditures	37,100	26,126	84,763	81,685
Debt including working capital deficiency[2][3]	91,020	106,124	91,020	106,124
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,531
Weighted average - diluted	121,649	121,557	121,597	121,616
Outstanding end of period – basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales[1]	36.24	26.37	30.18	26.15
Transportation costs	(5.57)	(5.94)	(5.84)	(5.82)
Revenue net of transportation	30.67	20.43	24.34	20.33
Royalties	(0.58)	(0.63)	(1.08)	(1.19)
Production costs	(5.46)	(5.68)	(5.50)	(6.04)
Field operating netback[2]	24.63	14.12	17.76	13.10
Realized (loss) gain on hedging	(8.65)	0.41	(3.03)	(0.40)
General and administrative	(0.55)	(0.94)	(0.82)	(1.05)
Interest and finance costs	(0.45)	(0.67)	(0.57)	(0.69)
Funds flow per Boe	14.98	12.92	13.34	10.96
Barrels of oil equivalent per day (6:1)	22,432	17,936	20,538	16,017
Natural gas production				
Thousand cubic feet per day	109,520	87,375	101,019	78,521
Price (Cdn$ per Mcf)[1]	5.56	3.34	3.98	3.61
Condensate production				
Barrels per day	2,453	1,914	2,141	1,685
Price (Cdn$ per barrel)[1]	58.74	69.53	75.61	61.80
NGL production				
Barrels per day	1,726	1,460	1,561	1,245
Price (Cdn$ per barrel)[1]	35.09	33.29	35.69	25.15
Wells drilled (net)	4.0	7.0	4.0	16.0
Wells completed (net)	2.5	3.0	10.5	12.0

(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 39 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

2018 FOURTH QUARTER HIGHLIGHTS

Production and funds flow reached record highs in the quarter as a result of diversified natural gas sales along with the performance of recent horizontal wells continuing to exceed expectations at both Nig and Umbach.

- Production increased to a record of 22,432 Boe per day which represents growth of 25% on a per-share basis from the prior year and also exceeded guidance of 19,000 to 21,000 Boe per day (production was rapidly increased in mid-November in response to a strengthening natural gas price at Chicago).
- Liquids production (field condensate plus gas plant NGL) grew by 24% year over year with liquids representing 19% of total production and 25% of production revenue.
- At the end of the quarter, there was an inventory of seven Montney horizontal wells (6.5 net) that had not started producing which included four completed wells (3.5 net). During the quarter, three wells (3.0 net) started production.
- At the Nig land block, the three wells completed in early 2018 have been producing for eight to eleven months with no decline to date and averaged 8.2 Mmcf per day raw gas in February which is approximately 1,520 Boe per day sales (20% liquids including liquids recovered at the gas plant).
- Diversified natural gas sales resulted in the realized price averaging $5.56 per Mcf which was significantly higher than Western Canadian pricing (AECO $1.48 per GJ and Station 2 $0.64 per GJ). Firm pipeline commitments required to diversify sales also result in a higher natural gas transportation cost which was $1.02 per Mcf (only 18% of the realized price).
- Hedging loss totaled $17.9 million with 69%, or $12.3 million, from Sumas price hedges. This was the result of a failure on the Enbridge T-south pipeline system on October 9th which materially reduced flows and increased the Sumas price to Cdn$14.67 per Mmbtu in the quarter versus the average hedged price of Cdn$2.92 per Mmbtu.
- Production costs, general and administrative, and interest and finance costs averaged $6.46 per Boe, a decrease of 11% year over year.
- Funds flow was a record $30.9 million, or $0.25 per share, a 39% increase on a per-share basis from last year which was largely from a higher natural gas price and higher production volumes.
- Capital investment was $37.1 million which included drilling four horizontal wells (4.0 net), completing three horizontal wells (2.5 net), and initial equipment deposits of $8.9 million for the gas plant at Nig.
- The balance sheet remains strong with debt including working capital deficiency being $91 million which represents 0.7 times annualized quarterly funds flow and 50% of the bank credit facility of $180 million.
- Commodity price hedges currently protect approximately 43% of forecast production for 2019.

2018 YEAR-END HIGHLIGHTS

Financial and operational results were consistent with or better than guidance for production, funds flow, operating costs per Boe and capital investment. Notably, year-over-year production growth per share of 28% was achieved while reducing debt including the working capital deficiency by $15 million.

- Production averaged 20,538 Boe per day which was consistent with guidance and represents growth of 28% on a per-share basis from last year.
- This was the eighth consecutive year that production per share has grown with growth averaging 28% per year over the last five years.

- Liquids production grew by 26% (condensate by 27%) with liquids representing 18% of total production and 35% of production revenue.

- Due to diversified natural gas sales, the realized natural gas price was $3.98 per Mcf which was materially higher than Western Canadian pricing (AECO $1.42 per GJ and Station 2 $1.19 per GJ).

- The corporate decline rate in 2018 was approximately 26% (December 2017 corporate production was 19,220 Boe per day with the same wells producing 14,160 Boe per day in December 2018 based on field estimates). This is a reduction from the 32% decline rate in 2017.

- Cost structure continues to decrease with production, general and administrative, and interest and finance expense averaging $6.89 per Boe, a decline of 11% from the previous year.

- Funds flow was a record $100.1 million ($0.82 per share), a year-over-year increase of 56% on a per-share basis with the improvement coming from production growth (+28%) and a higher funds flow netback (+22%) which resulted from higher commodity prices and a decrease in costs on a per-Boe basis.

- Return on capital employed was 10% and cash return on capital employed was 21%. Cash return on capital employed is based on funds flow which is a more meaningful measure of profitability given that return on capital employed is based on net income which can be significantly affected by non-cash mark-to-market gains and losses on hedging (for example, 2018 was a non-cash hedging loss of $5.8 million while 2017 was a non-cash hedging gain of $24.6 million).

- Capital investment totaled $85 million and included $14 million of investment into longer-term growth projects that will not contribute to production and funds flow until 2020 ($11 million in equipment deposits for the Nig gas plant and $3 million at Fireweed).

YEAR-END RESERVE EVALUATION HIGHLIGHTS

Reserve growth was consistent with production growth while capital efficiency continued to improve with the all-in PDP FD&A setting a record low at $5.24 per Boe while PDP recycle ratio using the funds flow netback set a record high at 2.5 times.

Reserves

(Mboe)	**Increase From Last Year**	**2018**	**2017**	**2016**
Proved Developed Producing (“PDP”)	+25%	42,204	33,729	25,395
Total Proved (“1P”)	+54%	149,905	97,617	77,097
Total Proved plus Probable (“2P”)	+41%	182,370	128,963	104,192
PDP as % of 2P		23%	26%	24%
1P as a % of 2P		82%	76%	74%
Reserve Life Index using fourth quarter production	PDP	5.2	5.2	5.2
(years)	1P	18.3	14.9	15.9
	2P	22.3	19.7	21.4

All-in Finding, Development & Acquisition (“FD&A”) Cost
Including Change in Future Development Capital (“FDC”)

($/Boe)	**2018**	**2017**	**2016**	**3-Year Total**
PDP	$5.24	$5.76	$6.89	$5.82
1P	$6.01	$3.06	$4.97	$5.10
2P	$5.10	$1.27	$5.48	$3.96

Recycle Ratio Using All-in FD&A Cost

	2018	2017	2016	3-Year Total
Funds Flow (000s)	$100,092	$64,080	$34,380	$198,552
Funds Flow netback ($/Boe)	$13.34	$10.96	$7.10	$10.92
PDP Recycle	2.5	1.9	1.0	1.9
1P Recycle	2.2	3.6	1.4	2.1
2P Recycle	2.6	8.6	1.3	2.8

- Reserve additions for PDP replaced 113% of annual production (698% for 1P and 712% for 2P).
- On a per-share basis, PDP reserves increased by 25%, 1P increased by 54% and 2P increased by 41%.
- Liquids reserves increased by 31% for PDP, 69% for 1P and 56% for 2P.
- Material future upside remains given that 2P reserves are recognized in only the upper Montney on 41.7 net sections which is 24% of the total Montney land position (172 net sections).
- Actual results achieved in 2018 were better than what was predicted in last year's evaluation with new wells completed in 2018 assigned estimated ultimate recoverable reserves averaging 8.9 Bcf gross raw gas which is 44% higher than the 2P estimate of 6.2 Bcf gross raw gas for future drilling locations in last year's evaluation. As a result of drilling longer horizontal wells with more frac stages, the actual cost to drill and complete a horizontal well in 2018 averaged $6.2 million which was higher than the estimated cost of $4.8 million used in last year's reserve evaluation.
- The before-tax PDP net present value ("NPV") discounted at 10% was $477 million, or $3.17 per share, after deducting debt including working capital deficiency, a year-over-year increase of 68% when the same price forecast is used (this year's price forecast used in last year's evaluation).

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas of 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 fourth quarter, seven sections of land were acquired.

Most of the land position is delineated with existing vertical wells, the 75 horizontal wells (70.9 net) drilled to date by Storm, and multiple producing horizontal wells on adjacent lands. The majority of the producing horizontal wells 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 well control.

Fourth quarter 2018 field activity included drilling four horizontal wells (4.0 net) and completing three horizontal wells (2.5 net), all at Umbach. Three horizontal wells (3.0 net) started production in October and November and there remains an inventory of seven horizontal wells (6.5 net) that had not started producing at the end of the quarter which includes four completed wells (3.5 net).

First quarter 2019 field activity is expected to include drilling five horizontal wells (5.0 net). Four wells will be drilled from a single pad at Nig (licensed for a total of eight wells) with two wells in the upper Montney, one in the mid and one in the lower. Higher field condensate-gas ratios are expected from the wells in the mid and lower Montney.

At Umbach (100% working interest), investment of approximately $18 million is planned in 2019 with activity including the drilling of one well (1.0 net), the tie-in of a two-well pad (2.0 net) and the completion of a three-well pad (3.0 net). Current field compression capacity totals 150 Mmcf per day raw gas and throughput in the fourth quarter averaged 124 Mmcf per day raw gas (includes 24 Mmcf per day raw from three wells at Nig). Growth is largely contingent on the Station 2 price as incremental natural gas production would be directed to Station 2. 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 (1-year term).

At Nig (100% working interest), approximately $95 million will be invested in 2019 for construction of a sour gas plant, pipelines, drilling and completing an acid gas injection well (1.0 net), and drilling, completing, and equipping four horizontal wells (4.0 net). The license application for the planned 50 Mmcf per day sour gas plant was submitted in September 2018 and, depending on when approvals are received, construction is expected to start in mid-2019 with start-up anticipated in late 2019 or early 2020. Produced raw natural gas contains approximately 0.2% H_2S. Total cost for the sour gas plant is estimated to be $81 million ($11.4 million invested in 2018, remainder in 2019) which includes $73 million for the gas plant, $4 million for an acid gas injection well and $4 million for a sales pipeline. The gas plant has a forecast operating cost of $2.00 per Boe which will reduce corporate operating costs to approximately $4.25 per Boe and is expected to add incremental production of approximately 1,500 Boe per day which primarily comes from improved liquids recovery (adds 1,100 barrels per day with 90% NGL while reducing process shrinkage by 5%).

The first three horizontal wells producing at Nig were completed in early 2018 and, to date, natural gas rates plus field condensate-gas ratios have been materially higher than at Umbach. Calendar day rates over the first 180 days have averaged 8.2 Mmcf per day raw gas plus 205 barrels per day of field condensate (approximately 1,570 Boe per day with 23% liquids including liquids recovered at the gas plant). The condensate-gas ratio during this period was approximately 50% higher than the average well at Umbach. There has been very little decline to date with rates in February averaging 8.2 Mmcf per day raw gas plus 150 barrels per day of field condensate based on field estimates.

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 deposits to order longer lead time equipment for a field compression facility. The license application for the 50 Mmcf per day field compression facility was submitted in January 2019 and, depending on when approvals are received, construction is expected to begin between late 2019 and early 2020 with start-up in the second half of 2020. Total 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 net investment of approximately $50 million to drill nine horizontal wells (4.5 net), complete six horizontal wells (3.0 net) and construct the field compression facility. Development at Fireweed is expected to increase condensate as a proportion of total production based on production history from several offsetting horizontal wells where first year average field condensate-gas ratios were 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach.

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.

The licensing process was recently changed (July 2018) and applications for wells, facilities, roads and pipelines at Nig, Umbach and Fireweed are subject to the BC Oil and Gas Commission's 'New Interim Measures Applied to Oil and Gas Applications'. Storm's lands are within Area 2 where the objective is restricted new surface disturbance. Some of Storm's license applications will result in new disturbance and have been referred for additional review which is extending the time required to obtain licenses. This would include pipelines and the gas plant at Nig plus pipelines, the facility and drilling at Fireweed. The additional time required for review is not currently quantifiable (the licensing process generally required five to six months before the new measures were implemented).

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not meaningful indicators of relative performance as wells after 2016 are initially rate restricted to manage fluid rates (for as long as nine months). 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 5 hz's	31	1850 m	3.5 Mmcf/d(2) 23 Bbls/Mmcf(3) 4 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	

(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 objective being 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 (condensate and butane) is priced in reference to WTI. The current hedge position protects approximately 43% of forecast production for 2019.

2019	Crude Oil	875 Bpd	WTI Cdn$71.24/Bbl floor, Cdn$84.60/Bbl ceiling
		625 Bpd	WTI Cdn$78.51/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	43,500 Mmbtu/d (36.7 Mmcf/d)	Chicago Cdn$3.26/Mmbtu
		8,400 Mmbtu/d (7.1 Mmcf/d)	Sumas Cdn$2.86/Mmbtu
		2,500 GJ/d (2.0 Mmcf/d)	AECO Cdn$1.94/GJ
		2,250 GJ/d (1.8 Mmcf/d)	Station 2 Cdn$1.73/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 diversification for sales 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) Preferential interruptible adds up to 14 Mmcf/d
(2) Sumas price less US$0.69/Mmbtu

In the fourth quarter, 63% of natural gas sales were at a Chicago price, 26% at Western Canadian pricing, and 11% at a 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

For the first quarter of 2019, production is forecast to be 17,500 to 20,000 Boe per day. As was previously communicated in a press release dated January 15, 2019, the McMahon Gas Plant was shut in for 17 days starting January 2nd to repair a failure on the flare system piping. During this time, production was reduced to 4,500 Boe per day. Production to date has averaged 18,000 Boe per day based on field estimates.

Production in the second and third quarters of 2019 is expected to be approximately 20,000 to 21,000 Boe per day based on current indications for Western Canadian natural gas prices during this period ($0.75 per GJ at Station 2 and $1.25 per GJ at AECO). This level of production is the minimum that would fulfill firm transportation commitments and assumes interruptible service on the Alliance Pipeline is not available.

Updated guidance for 2019 is summarized below:

- forecast commodity prices updated to reflect pricing to date in 2019 plus the approximate current forward strip for the remainder of the year;
- estimated annual funds flow decreased primarily as a result of weaker Western Canadian propane and butane prices (primarily butane) which decreases the NGL price net of transportation to approximately 10% to 15% of WTI in Cdn$ for the next NGL contract period from April 2019 to March 2020 (versus an average of 42% in 2018); and
- the number of horizontal wells starting production decreased to 9.0 gross from 11.0 gross with the start-up of two horizontal wells accelerated into the fourth quarter of 2018 to take advantage of stronger natural gas prices.

2019 Guidance

	Initial November 13, 2018	February 28, 2019
Cdn$/US$ exchange rate	0.78	0.76
Chicago daily natural gas - US$/Mmbtu	$2.50	$2.60
Sumas monthly natural gas - US$/Mmbtu	$2.50	$3.10
AECO daily natural gas - Cdn$/GJ	$1.50	$1.60
Station 2 daily natural gas - Cdn$/GJ	$1.25	$1.25
WTI - US$/Bbl	$60.00	$55.00
Edmonton condensate diff - US$/Bbl	-$8.00	-$5.50
Est revenue net of transport (excl hedges) - $/Boe	$17.50 - $18.00	$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	$11.05	$11.30
Est hedging loss - $ million		$7.0 - $8.0
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 % liquids	23,000 – 25,000 18%	23,000 - 25,000 18%
Forecast annual production - Boe/d % liquids	21,000 – 24,000 18%	21,000 - 24,000 18%
Est annual funds flow - $ million	$72.0 - $88.0	$67.0 - $79.0(1)
Horizontal wells drilled - gross Horizontal wells completed - gross Horizontal wells starting production - gross	8 (6.5 net) 11 (9.5 net) 11 (11.0 net)	9 (7.5 net) 11 (9.5 net) 9 (9.0 net)

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

A failure on the Enbridge T-south pipeline system on October 9, 2018 affected the natural gas price at Station 2 which averaged $0.64 per GJ in the fourth quarter of 2018, a differential to AECO of -$0.84 per GJ (compared to an average price of $1.37 per GJ and differential of -$0.04 per GJ in the nine months before the failure). Flow has been restored to approximately 80% to 85% of the flow prior to the failure and the timing to fully restore capacity is not currently known although is unlikely to be before August 2019 (requires completion of engineering assessments on various segments along with review and approval from the National Energy Board). The Station 2 price is expected to remain depressed until capacity is restored or until the NGTL North Montney extension into northeast British Columbia is in service which is anticipated to be in the fourth quarter of 2019 (contracted capacity 1.5 Bcf per day). The financial effect on Storm has not been material given that less than 15% of natural gas sales are at Station 2 pricing.

Since 2015, financial results have improved materially with funds flow reaching a record $100 million in 2018, an increase of 141% on a per-share basis. Importantly, debt including working capital deficiency has increased by only 47% during this period (from $62 million at the end of 2015 to $91 million at the end of 2018). This has been a result of production growth (+103% per share), increased revenue per Boe net of transportation (+39%), and a per-Boe decrease in production, general and administrative, and interest and finance expense (-32%).

In 2019, estimated capital investment to maintain production at 2018 levels of 20,000 to 21,000 Boe per day is less than $10 million which includes connection and start-up of three horizontal wells that were completed in 2018 plus expenditures for various minor projects. The remaining investment of $118 million will be directed to growth opportunities that offer attractive full-cycle rates of return at current commodity prices. At Nig, a 50 Mmcf per day sour gas plant will be constructed in the second half of 2019 which will significantly reduce per-Boe operating costs and increase liquids recovery. At Fireweed, a 50 Mmcf per day field compression facility will be constructed in mid-2020 where higher field condensate rates are expected from horizontal wells. At Umbach, activity and production can and will be increased relatively quickly if supported by the Station 2 natural gas price given existing unused field compression capacity.

Growth has been accomplished while improving the cash return on average capital employed to 21% in 2018 from 10% in 2015. Generating a strong return on invested capital will continue to be a focus of Storm's business plan.

The Company's near-term growth plan is expected to increase the proportion of liquids and decrease per-Boe operating costs which reduces exposure to current low Western Canadian natural gas prices. Production is expected to grow to approximately 25,000 Boe per day by the end of 2019 (18% liquids) and to more than 30,000 Boe per day by the end of 2020 (21% liquids). Growth will be financed with funds flow and debt. Maintaining a strong balance sheet remains a priority and, as a result, capital investment and activity will continue to be flexible and may be accelerated or reduced depending on commodity prices.

With horizontal well results continuing to improve as length is increased and with 2P reserves recognized in only the upper Montney on less than 25% of the total land position at Umbach, Nig and Fireweed, material future upside remains. This leaves Storm well positioned to continue growing funds flow and asset value on a per-share basis and is a consideration when evaluating acquisition or diversification opportunities.

The growth and significant improvement in financial results over the last several years would not have happened without the successful efforts of Storm's employees and I would like to thank them for their hard work and also thank Storm's Board of Directors for their invaluable advice, guidance and support.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 28, 2019

RESERVES AT DECEMBER 31, 2018

Storm's year-end reserve evaluation effective December 31, 2018 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 20, 2018. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2018 was used to determine estimates of net present value ("NPV"). Storm's Reserves Committee, which is made up of independent and appropriately qualified directors, has reviewed and approved the evaluation prepared by InSite, and the report of the Reserves Committee has been accepted by the Company's Board of Directors.

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). In addition to the information disclosed in this report, more detailed information will be included in Storm's Annual Information Form for the year ended December 31, 2018 (the "AIF").

Summary

- Proved developed producing reserves ("PDP") increased to 42,204 Mboe during 2018, a 25% increase over the 2017 year-end PDP reserves of 33,729 Mboe. Total proved reserves ("1P") increased to 149,905 Mboe, a 54% increase over 2017 year-end 1P reserves of 97,617 Mboe. Total proved plus probable reserves ("2P") increased to 182,370 Mboe, a 41% increase over 2017 year-end 2P reserves of 128,963 Mboe.

- Reserve additions in 2018 replaced 113% of production for PDP reserves, 698% for 1P reserves and 712% for 2P reserves.

- 2P reserves include 889 Bcf of natural gas and 34 Mmbbl of NGL at year-end 2018. The NGL component includes 56% condensate (19 Mmbbl), 23% butane (8 Mmbbl) and 21% propane (7 Mmbbl).

- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $5.24 per Boe for PDP, $6.01 per Boe for 1P and $5.10 per Boe for 2P.

- Technical revisions increased PDP reserves by 2,574 Mboe (7.6%), 1P reserves by 16,432 Mboe (16.8%) and 2P reserves by 21,291 Mboe (16.5%). PDP revisions were primarily due to well performance exceeding the InSite forecast from the previous year, while 1P and 2P revisions were the result of increased reserve assignments due to using longer horizontal wells.

- Breaking down 2P reserves by area, 81.9% is at Umbach, 17.7% is at Nig, 0.2% is at the Horn River Basin ("HRB") and 0.2% is at Grande Prairie.

- Future development costs ("FDC") were $686 million on a 1P basis and $707 million on a 2P basis and are fully financed from forecast cash flow within four years which complies with the Canadian Oil and Gas Evaluation ("COGE") Handbook.

- FDC increased from 2017 predominantly due to three factors: investment associated with the Nig Gas Plant in 2019; a modest increase in future drilling locations; and increased cost to drill and complete a horizontal well given longer well lengths and additional completion stages.

- At Umbach and Nig there are 88.6 net 2P future horizontal drills assigned an average of 7.9 Bcf gross raw gas (last year was 78.6 net 2P locations with 6.2 Bcf gross raw gas). There are no future drilling locations recognized at Fireweed.

- Wells drilled in 2018 were assigned an average of 8.9 Bcf gross raw gas on a 2P basis.

- At Umbach and Nig, 2P reserves were recognized in the upper Montney on 41.7 net sections (an increase of 8.0 net sections from last year), 1P on 26.2 net sections and PDP on 14.5 net sections. DPIIP averages 48 Bcf gross raw gas per section in the upper Montney (total net DPIIP 2.0 Tcf on 41.7 net sections). Forecast recovery of DPIIP totals 55% for 2P reserves.

- FDC includes $166 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $55 million net for future infrastructure expansion). $71 million is allocated to the Nig area gas plant and $92 million is allocated to infrastructure expansion at Umbach South and Umbach North.

- The estimated cost to drill and complete a future Montney horizontal well at Umbach increased to $5.5 million compared to $4.8 million used in the previous year's reserve evaluation as a result of using longer horizontal wells with more frac stages.

(1) The all-in calculation reflects the result of Storm's entire capital investment program as it takes into account the effect of acquisitions, dispositions and revisions, as well as the change in FDC.

INFORMATION REGARDING DISCLOSURE ON OIL AND GAS RESERVES AND RESOURCES

All amounts are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("Boe") based on 6 Mcf:1 Boe. The Boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not recognize a value equivalent at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. Production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, unless otherwise stated. Unless otherwise specified, all reserves volumes are based on "company gross reserves" using forecast prices and costs. The oil and gas reserves statement for the year ended December 31, 2018, which will include complete disclosure of oil and gas reserves and other information in accordance with NI 51-101, will be contained within the AIF which will be available on SEDAR.

References to estimates of oil and gas classified as DPIIP are not, and should not be confused with, oil and gas reserves.

Gross Company Interest Reserves as at December 31, 2018
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	207,828	7,566	42,204
Proved non-producing	5,132	91	947
Total proved developed	212,960	7,657	43,151
Proved undeveloped	518,405	20,354	106,755
Total proved	731,365	28,011	149,905
Probable additional	158,126	6,110	32,464
Total proved plus probable	889,492	34,121	182,370

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2018
(Gross company interest reserves before deduction of royalties payable)

	6:1 Oil Equivalent (Mboe)			
	Proved Developed Producing	Total Proved	Probable	Proved plus Probable
December 31, 2017 – opening balance	33,729	97,617	31,346	128,963
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	13,393	43,347	(3,739)	39,608
Dispositions	-	-	-	-
Technical revisions	2,626	16,516	4,861	21,377
Economic factors	(52)	(84)	(2)	(86)
Production	(7,492)	(7,492)	-	(7,492)
December 31, 2018 – closing balance	42,204	149,905	32,464	182,370

Numbers in this table may not add due to rounding.

Reserve Life Index (“RLI”) Using Fourth Quarter Production

(Years)	2018	2017	2016
PDP	5.2	5.2	5.2
1P	18.3	14.9	15.9
2P	22.3	19.7	21.4

Future Development Costs (“FDC”)

	Proved ($M)	Proved Plus Probable ($M)
2019	107,300	107,300
2020	228,939	228,939
2021	233,362	233,362
2022	116,860	137,575
2023	-	-
Total FDC - undiscounted	686,461	707,176
Total FDC - discounted at 10%	618,923	635,441

($million)	2018	2017	2016
1P FDC	$ 686	$ 412	$ 413
2P FDC	$ 707	$ 481	$ 524

Note: InSite escalates capital costs at 2% per year after 2019.

All-in Finding, Development and Acquisition Costs (“FD&A”) (including acquisitions, dispositions and revisions)

Proved Developed Producing FD&A Cost (All-in)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Total capital including change in FDC (000s)	$ 83,641	$ 81,685	$ 64,938	$ 230,264
Total reserve additions (Mboe)	15,967	14,180	9,424	39,571
All-in PDP FD&A cost (per Boe)	$ 5.24	$ 5.76	$ 6.89	$ 5.82

Total Proved FD&A Cost (All-in)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	274,814	(1,127)	(22,669)	251,018
Total capital including change in FDC (000s)	$ 359,577	$ 80,558	$ 42,269	$ 482,404
Total reserve additions (Mboe)	59,780	26,366	8,501	94,647
All-in 1P FD&A cost (per Boe)	$ 6.01	$ 3.06	$ 4.97	$ 5.10

Total Proved Plus Probable FD&A Cost (All-in)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	226,058	(42,755)	(19,395)	163,908
Total capital including change in FDC (000s)	$ 310,821	$ 38,930	$ 45,543	$ 395,294
Total reserve additions (Mboe)	60,899	30,617	8,308	99,824
All-in 2P FD&A cost (per Boe)	$ 5.10	$ 1.27	$ 5.48	$ 3.96

Finding and Development Costs ("F&D")
(excluding acquisitions, dispositions and revisions)

Total Proved F&D Cost	2018	2017	2016	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	274,814	(1,127)	(22,669)	251,018
Total capital including change in FDC (000s)	$ 359,577	$ 80,558	$ 42,269	$ 482,404
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	43,347	16,669	5,182	65,199
1P F&D cost (per Boe)	$ 8.30	$ 4.83	$ 8.16	$ 7.40

Total Proved Plus Probable F&D Cost	2018	2017	2016	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	226,058	(42,755)	(19,395)	163,908
Total capital including change in FDC (000s)	$ 310,821	$ 38,930	$ 45,543	$ 395,294
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	39,608	19,615	4,890	64,112
2P F&D cost (per Boe)	$ 7.85	$ 1.98	$ 9.31	$ 6.17

Net Present Value Summary (before tax) as at December 31, 2018

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	693,974	561,063	476,842	419,619	378,559
Proved non-producing	6,795	4,763	3,506	2,673	2,088
Total proved developed	700,769	565,826	480,348	422,292	380,647
Proved undeveloped	1,609,850	976,620	634,522	426,964	290,364
Total proved	2,310,619	1,542,446	1,114,870	849,257	671,011
Probable additional	781,393	384,353	230,041	156,288	115,536
Total proved plus probable	3,092,013	1,926,799	1,344,911	1,005,544	786,547

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2018

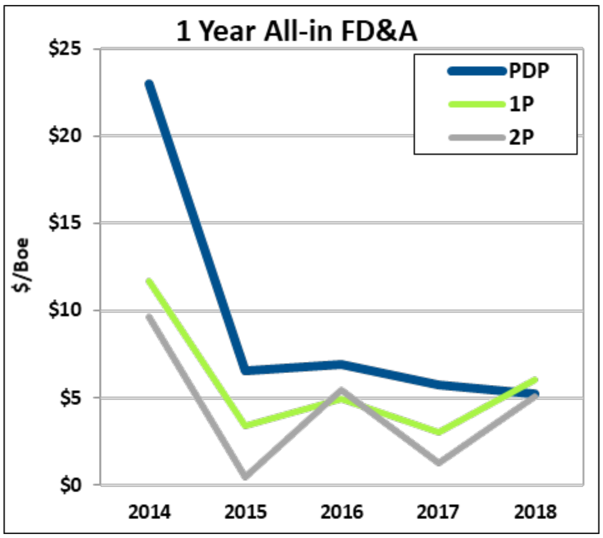
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

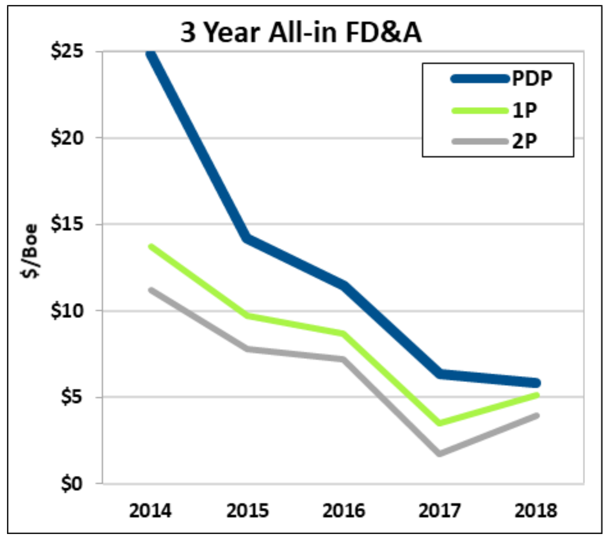
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	633,691	522,539	450,976	401,549	365,520
Proved non-producing	5,026	3,522	2,594	1,979	1,545
Total proved developed	638,717	526,061	453,570	403,528	367,065
Proved undeveloped	1,191,494	705,732	441,551	280,585	174,436
Total proved	1,830,211	1,231,792	895,120	684,113	541,501
Probable additional	578,230	284,148	169,854	115,289	85,207
Total proved plus probable	2,408,440	1,515,940	1,064,974	799,401	626,708

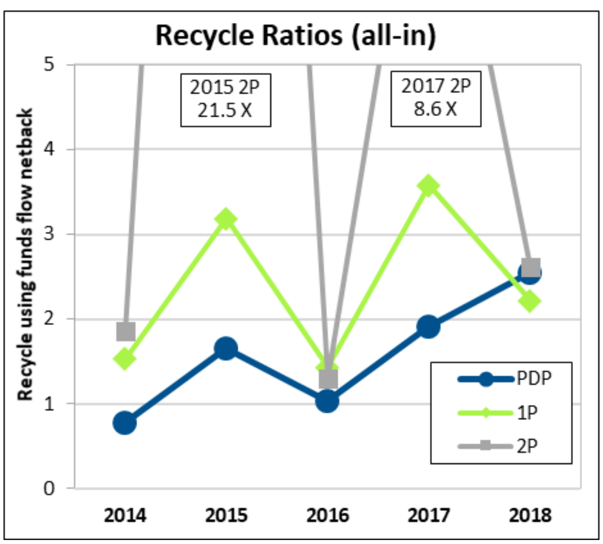
Numbers in this table may not add due to rounding.

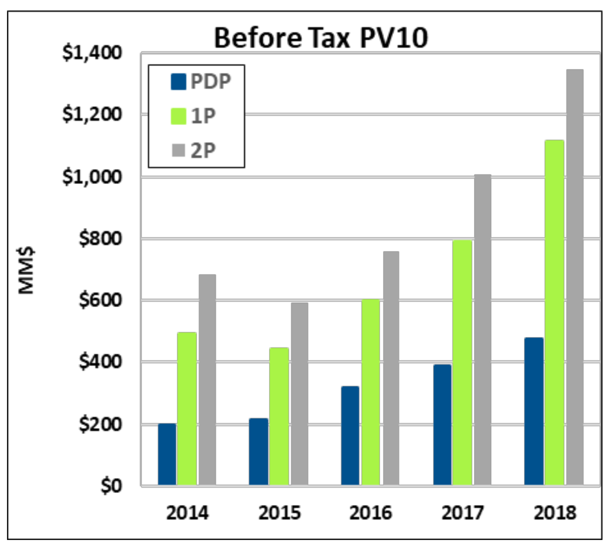
InSite Escalating Price Forecast as at December 31, 2018

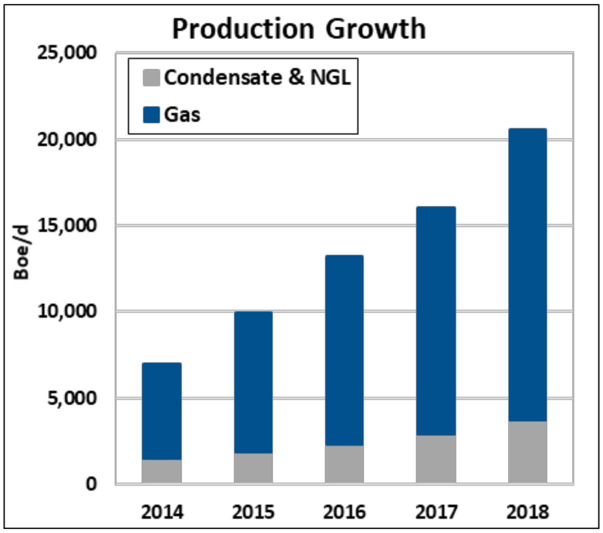
	Exchange Rate (US$/Cdn$)	WTI Crude Oil (US$/Bbl)	Condensate (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	BC Station 2 (Cdn$/Mmbtu)
2019	0.76	57.00	67.95	3.00	1.90	1.43
2020	0.78	64.00	78.95	3.15	2.29	1.97
2021	0.80	68.00	83.72	3.35	2.71	2.46
2022	0.80	71.00	86.58	3.50	3.03	2.78
2023	0.80	72.80	88.60	3.62	3.21	2.96

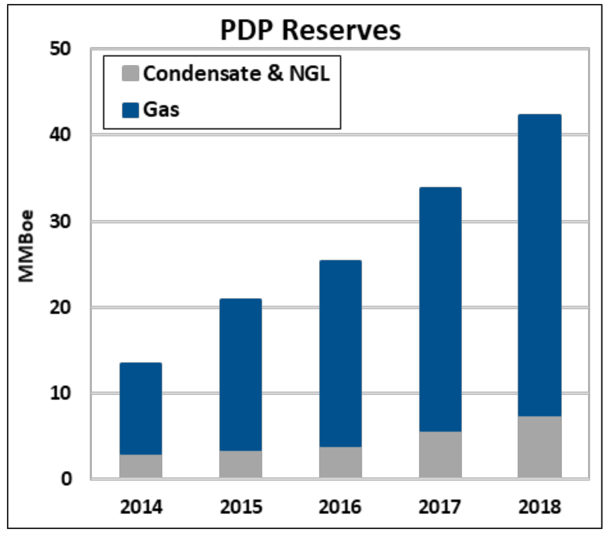


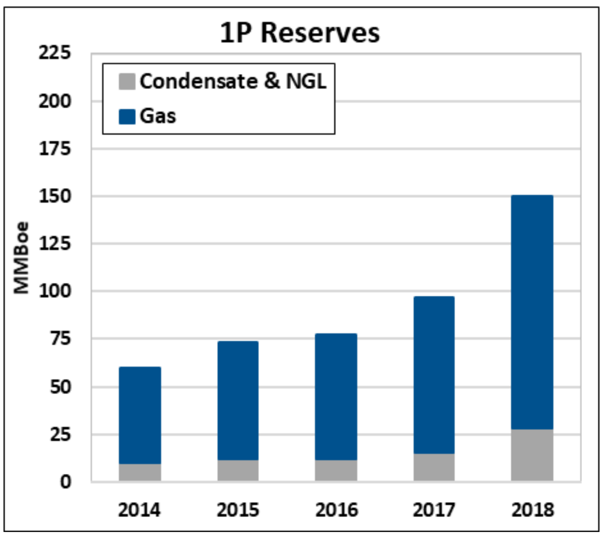


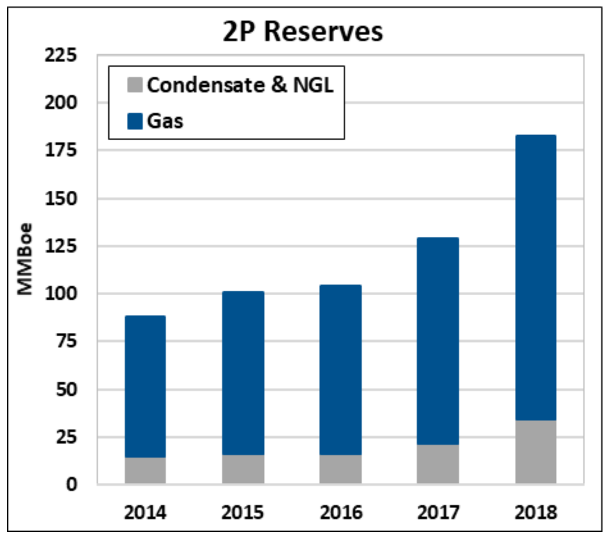


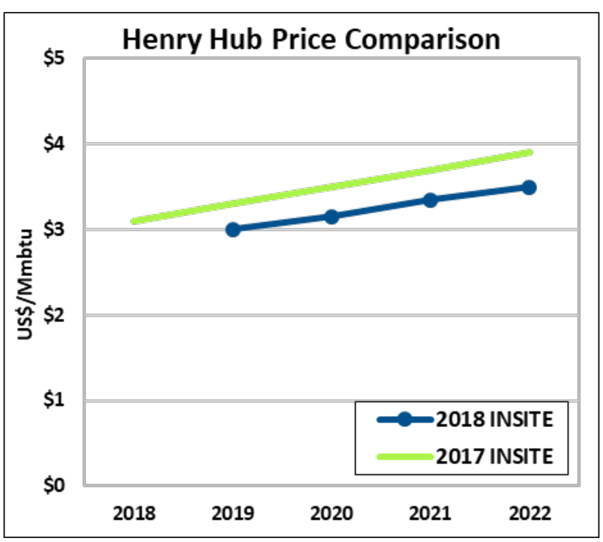


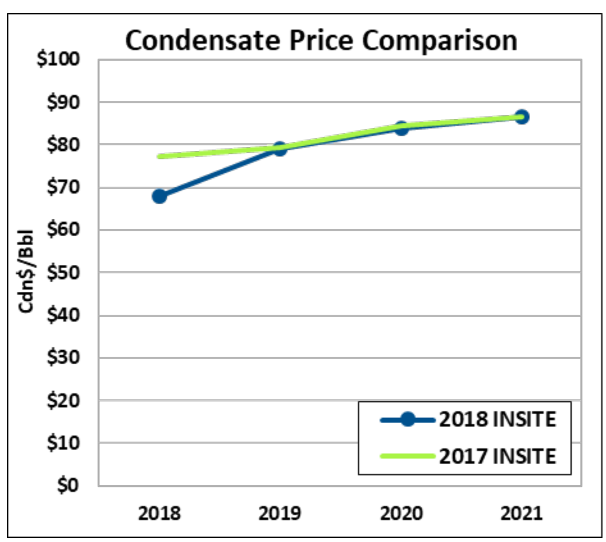

Production Growth
Condensate & NGL
Gas
Boe/d
25,000
20,000
15,000
10,000
5,000
0
2014
2015
2016
2017
2018

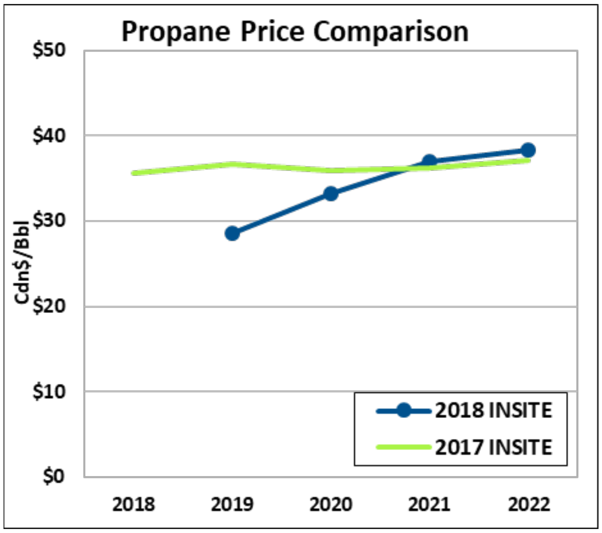

PDP Reserves
Condensate & NGL
Gas
MMBoe
50
40
30
20
10
0
2014
2015
2016
2017
2018

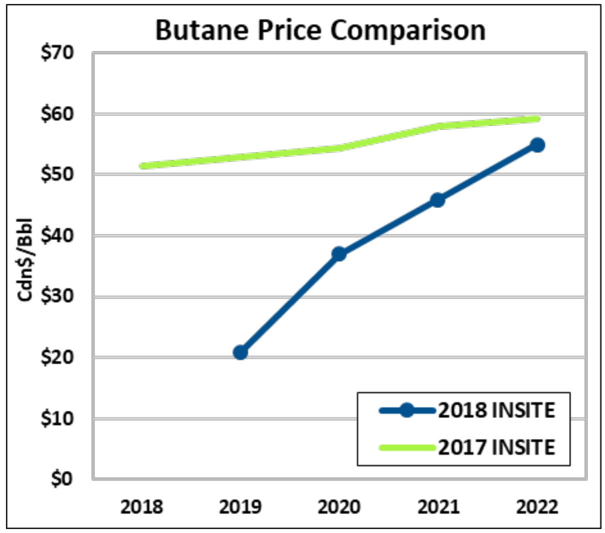

1P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2014
2015
2016
2017
2018


2P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2014
2015
2016
2017
2018


Henry Hub Price Comparison
US$/Mmbtu
$5
$4
$3
$2
$1
$0
2018 INSITE
2017 INSITE
2018
2019
2020
2021
2022


Condensate Price Comparison
Cdn$/Bbl
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
2018 INSITE
2017 INSITE
2018
2019
2020
2021


Propane Price Comparison
$50
$40
$30
$20
$10
$0
Cdn$/Bbl
2018
2019
2020
2021
2022
2018 INSITE
2017 INSITE


Butane Price Comparison
$70
$60
$50
$40
$30
$20
$10
$0
Cdn$/Bbl
2018
2019
2020
2021
2022
2018 INSITE
2017 INSITE

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 February 28, 2019 for the period ended December 31, 2018 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, 2018 and the MD&A dated February 28, 2019 for the period ended December 31, 2018 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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