NEWS RELEASE

February 27, 2020
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, 2019

Storm has also filed its audited consolidated financial statements as at December 31, 2019 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, 2019, as well as reserves information at December 31, 2019, appears below and should be read in conjunction with the related financial statements and MD&A.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
FINANCIAL				
Revenue from product sales[(1)]	48,671	74,799	173,422	226,258
Funds flow	18,469	30,941	59,549	100,092
Per share - basic and diluted ($)	0.15	0.25	0.49	0.82
Net income	2,906	26,810	11,313	40,063
Per share - basic and diluted ($)	0.02	0.22	0.09	0.33
Cash return on capital employed ("CROCE")[(2)]	12%	21%	12%	21%
Return on capital employed ("ROCE")[(2)]	4%	10%	4%	10%
Capital expenditures	23,913	37,100	96,843	84,763
Debt including working capital deficiency[(2)(3)]	128,901	91,020	128,901	91,020
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,649	121,557	121,597
Outstanding end of period - basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales[(1)]	23.64	36.24	23.54	30.18
Transportation costs	(5.20)	(5.57)	(5.66)	(5.84)
Revenue net of transportation	18.44	30.67	17.88	24.34
Royalties	(1.59)	(0.58)	(1.11)	(1.08)
Production costs	(5.67)	(5.46)	(5.87)	(5.50)
Field operating netback[(2)]	11.18	24.63	10.90	17.76
Realized gain (loss) on risk management contracts	(0.80)	(8.65)	(1.20)	(3.03)
General and administrative	(0.70)	(0.55)	(0.93)	(0.82)
Interest and finance costs	(0.71)	(0.45)	(0.68)	(0.57)
Funds flow per Boe	8.97	14.98	8.09	13.34
Barrels of oil equivalent per day (6:1)	22,375	22,432	20,182	20,538
Natural gas production				
Thousand cubic feet per day	108,679	109,520	98,458	101,019
Price (Cdn$ per Mcf)[(1)]	3.28	5.56	3.21	3.98
Condensate production				
Barrels per day	2,416	2,453	2,138	2,141
Price (Cdn$ per barrel)[(1)]	66.56	58.74	66.03	75.61
NGL production				
Barrels per day	1,846	1,726	1,634	1,561
Price (Cdn$ per barrel)[(1)]	6.11	35.09	10.75	35.69
Wells drilled (net)	-	4.0	6.0	4.0
Wells completed (net)	-	2.5	5.0	10.5

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 40 of the MD&A. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts, decommissioning liability and lease liability.

PRESIDENT'S MESSAGE

2019 FOURTH QUARTER HIGHLIGHTS

The start-up of a four well pad at Nig in late November increased production while funds flow benefitted from the increase in production and from an improvement in natural gas prices at AECO and Station 2. Construction continued on the Nig Gas Plant which was completed and started up February 22, 2020 (previously expected to be in January 2020).

- Production at 22,375 Boe per day was an increase of 20% from the previous quarter and was largely unchanged from the previous year. Production was reduced by approximately 500 Boe per day due to curtailments in October as a result of the low Station 2 price ($0.36 per GJ).

- Liquids production (field condensate plus gas plant NGL) increased 2% from last year to total 4,262 barrels per day, represented 19% of total production and contributed 33% of production revenue.

- A four well pad at Nig started production in late November with initial rates from the three wells in the upper/mid Montney being the same as earlier wells; however, longer-term rates are expected to be lower given tighter interwell spacing on the newest wells (400 metres versus 465 metres for earlier wells). The fourth well in the lower Montney has a higher condensate rate while the gas rate is lower (IP90 5.5 Mmcf per day raw gas plus 315 barrels per day field condensate).

- Revenue was $23.64 per Boe, a decline of $12.60 per Boe or 35% from last year, mainly from lower NGL and natural gas prices. The NGL price declined 83% as a result of lower North American propane prices and a reduction in the contracted plant gate price for propane and butane during the current marketing period from April 2019 to March 2020. The natural gas price declined 41% as a result of lower pricing in the Chicago and Sumas markets (66% of sales).

- Production, general and administrative, and interest and finance costs were $7.08 per Boe, a year-over-year increase of $0.62 per Boe with interest expense increasing $0.26 per Boe (higher debt level associated with funding construction of the Nig Gas Plant) and production cost increasing $0.21 per Boe (inflation escalator increasing third-party gas processing fees plus the scheduled increase in BC carbon tax in April 2019).

- Hedging loss of $1.6 million resulted from Sumas price hedges that were entered into before a failure on the Enbridge T-south pipeline in October 2018 which decreased throughput and increased the Sumas price (repairs completed late November 2019).

- Funds flow was $18.5 million or $0.15 per share with the year-over-year decrease of 40% per share largely the result of revenue being reduced by lower commodity prices.

- Net income was $2.9 million compared to $26.8 million in the prior year with the decline primarily attributable to lower commodity prices reducing revenue and funds flow.

- Capital investment of $24 million included $19 million for the Nig Gas Plant project plus $3 million to pipeline connect a four well pad at Nig. Investment was less than guidance ($32 to $37 million) with $9 million for the construction of the Nig Gas Plant being shifted into the first quarter of 2020 as a result of delays in equipment deliveries (damage to a bridge south of Fort St. John in late November required loads to be rerouted).

- Total debt including working capital deficiency was $129 million or 1.7 times annualized quarterly funds flow and represents 63% utilization of the $205 million bank line. The year-over-year increase in total debt is a result of the large investment in the Nig Gas Plant project in 2019 which totaled $61 million (63% of total investment).

- Commodity price hedges currently protect approximately 29% of forecast production in the first half of 2020 and 7% in the second half of 2020.

2019 YEAR-END HIGHLIGHTS

Production and funds flow were below initial guidance provided in November 2018 mainly as a result of unplanned outages, lower NGL pricing for the contract year starting April 2019, and from production curtailments due to low natural gas prices during the summer. As forecast funds flow declined during 2019, capital investment was reduced which resulted in fewer Montney horizontal wells being drilled and completed (six drills and five completions versus initial guidance for eight drills and 11 completions).

- Production averaged 20,182 Boe per day, a 2% decrease from the previous year, and was below initial guidance provided in November 2018 (21,000 to 24,000 Boe per day) mainly as a result of 31 days of unplanned outages at the McMahon Gas Plant and production curtailments during April to October due to low natural gas prices (Station 2 averaged $0.57 per GJ during this period).

- The realized natural gas price at $3.21 per Mcf was materially higher than Western Canadian pricing (AECO daily index $1.67 per GJ and Station 2 $0.96 per GJ) as a result of diversified sales.

- During 2019, seven horizontal wells started production and contributed approximately 2,600 Boe per day to average annual production and 4,700 Boe per day to fourth quarter production.

- Production, general and administrative, and interest and finance costs were $7.48 per Boe, an increase of $0.59 per Boe, largely as a result of the year-over-year decline in production caused by unplanned outages. Also contributing to the increase is higher interest expense associated with higher debt levels to fund construction of the Nig Gas Plant and higher production cost with the inflation escalator increasing third-party gas processing fees.

- Funds flow of $60 million ($8.09 per Boe) declined 40% from the previous year mainly from lower commodity prices reducing revenue per Boe by 22%.

- Net income of $11 million ($1.55 per Boe) declined 72% from the previous year primarily as a result of the decline in funds flow.

- Return on capital employed (ROCE) was 4% and cash return on capital employed (CROCE) was 12%. Non-cash hedging gains or losses will affect ROCE which is based on net income but does not affect CROCE which is based on funds flow.

- Capital investment was $97 million with approximately $61 million, or 63%, directed to the Nig Gas Plant project (gas plant, sales pipeline and acid gas injection well) which is expected to increase liquids production and reduce production cost after start-up in the first quarter of 2020.

RESERVE EVALUATION HIGHLIGHTS

Reserves increased modestly in 2019 as a result of positive technical revisions and additional future drilling locations being recognized in the Nig area.

Reserves

(Mboe)	YOY Increase	2019	2018	2017
Proved Developed Producing (“PDP”)	+3%	43,322	42,204	33,729
Total Proved (“1P”)	+4%	156,118	149,905	97,617
Total Proved plus Probable (“2P”)	+7%	195,483	182,370	128,963
PDP as % of 2P		22%	23%	26%
1P as a % of 2P		80%	82%	76%
Reserve Life Index using fourth quarter production	PDP	5.3	5.2	5.2
(years)	1P	19.1	18.3	14.9
	2P	23.9	22.3	19.7

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

($/Boe)	2019	2018	2017	3-Year Total
PDP	$11.43	$5.24	$5.76	$6.79
1P	$3.90	$6.01	$3.06	$4.94
2P	$3.16	$5.10	$1.27	$3.70

Recycle Ratio Using All-in FD&A Cost

	2019	2018	2017	3-Year Total
Funds Flow (000s)	$59,549	$100,092	$64,080	$223,604
Funds Flow Netback ($/Boe)	$8.09	$13.34	$10.96	$10.80
PDP Recycle	0.7	2.5	1.9	1.6
1P Recycle	2.1	2.2	3.6	2.2
2P Recycle	2.6	2.6	8.6	2.9

- PDP FD&A was higher in 2019 as a result of $61 million invested in the Nig Gas Plant project.
- There are no reserves or financial benefit included for the Nig Gas Plant in PDP, however, incremental reserves and the lower production cost is recognized in 1P (adds 4,873 Mboe) and 2P (adds 6,771 Mboe).
- There are no PDP, 1P or 2P reserves assigned to the Fireweed area.
- PDP additions totaled 8,469 Mboe from four new wells at Nig plus positive technical revisions and replaced 115% of annual production (185% for 1P and 278% for 2P).
- On a per-share basis, PDP reserves increased by 3%, 1P increased by 4% and 2P increased by 7%.
- Material future upside remains given that 2P reserves are recognized in only the upper Montney on 44 net sections which is approximately 25% of the total Montney land position (172 net sections).
- Future drilling locations included in 2P reserves total 92.6 net horizontal wells with 13.0 net at Nig and 79.6 net at Umbach.

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 totals 121,000 net acres (172 net sections) with 79 horizontal wells (74.4 net) drilled to date.

Fourth quarter field activity was mainly focused on the Nig Gas Plant project which included delivery of major equipment to the site along with on-site construction activities and starting construction of the sales gas and NGL pipelines. In addition, the pipeline tie-in of a four well (4.0 net) pad at Nig was completed in late November after being delayed by rain and wet field conditions.

During the quarter, four new wells started production leaving an inventory at the end of the quarter of five (4.5 net) drilled Montney horizontal wells that had not started producing which included one (0.5 net) completed well.

Field activity in the first quarter will include completing construction of the Nig Gas Plant and associated sales gas and NGL pipelines plus the completion and tie-in of a three well pad at West Umbach.

At Umbach (100% working interest), produced raw natural gas contains 1.2% H_2S with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant where firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon plus 15 Mmcf per day at Stoddart). Field compression capacity totals 150 Mmcf per day raw gas with throughput in the fourth quarter averaging 112 Mmcf per day (including 29 Mmcf per day from Nig which has been redirected to the recently commissioned Nig Gas Plant). Activity in 2020 will include completing and connecting a three well (3.0 net) pad at West Umbach in the first quarter. There remains significant capacity for future growth which is contingent on the Station 2 natural gas price.

At Nig (100% working interest), produced raw natural gas contains 0.1% H_2S and is directed to the recently constructed 50 Mmcf per day sour gas plant that started up in late February 2020. Total estimated cost of the Nig Gas Plant project remains at $86 million which includes the facility, an eight-kilometre sales gas pipeline and drilling/completing a horizontal well for acid gas injection ($11 million in 2018, $61 million in 2019, $14 million in 2020). The estimated cost was increased to $86 million in November 2019 (from $81 million) as a result of the cost for site construction being higher than forecast and design changes. At full capacity, incremental production from the gas plant versus processing at the McMahon Gas Plant is expected to be 1,500 Boe per day (70% liquids) given the higher NGL recovery and reduced gas shrinkage. In addition, eliminating third-party processing fees will result in an operating cost of less than $2.00 per Boe which will reduce the corporate operating cost. Incremental liquids are expected to include approximately 93% NGL (propane/butane) and 7% condensate with the majority of the propane being sold at the Far East Asia Index price via the Altagas Ridley Island Export Terminal (‘RIPET’). Activity in 2020 is expected to include completing the Nig Gas Plant plus drilling and completing two to four wells (2.0 to 4.0 net).

At Fireweed (50% working interest), construction of a 50 Mmcf per day field compression facility (expandable to 100 Mmcf per day) is anticipated to begin in mid-2020 with start-up in late 2020 or early 2021. The estimated cost for the facility, a 16-kilometre access road and sales pipeline is $38 million gross. There is currently one standing well (0.5 net) that has been completed which averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate and 1,140 barrels per day of frac water over the last 12 hours of a six-day clean-up (final flowing casing pressure of 4,800 kPa). 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. Investment in 2020 is expected to total $36 million which will include the construction of the facility and related pipelines and roads plus drilling four wells (2.0 net) and completing three wells (1.5 net).

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not reliable indicators of relative longer-term performance since wells are initially rate restricted to manage fluid rates. Note that the 2019 wells at Nig in the upper/mid Montney were drilled on tighter interwell spacing versus the 2018 wells (400 metres versus 465 metres) which is expected to reduce longer-term rates and ultimate recovery.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2017 - 2018 19 hz's	34	1895 m	4.6 Mmcf/d[1] 24 Bbls/Mmcf[2] 19 hz's	4.4 Mmcf/d[1] 20 Bbls/Mmcf[2] 19 hz's	4.0 Mmcf/d[1] 15 Bbls/Mmcf[2] 17 hz's
Nig 2018 upper 3 hz's	37	2180 m	8.1 Mmcf/d[1] 29 Bbls/Mmcf[2] 3 hz's	8.2 Mmcf/d[1] 25 Bbls/Mmcf[2] 3 hz's	7.5 Mmcf/d[1] 21 Bbls/Mmcf[2] 3 hz's
Nig 2019 upper/mid 3 hz's	42	2240 m	8.1 Mmcf/d[1] 20 Bbls/Mmcf[2] 3 hz's		
Nig 2019 lower 1 hz	42	2280 m	5.5 Mmcf/d[1] 57 Bbls/Mmcf[2] 1 hz		

(1) Raw gas rate.
(2) 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 8 Bcf and 14 Bcf raw gas type curves (internal estimates) to forecast production at Umbach and Nig respectively. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING

Commodity price hedges are used to support longer-term growth by protecting pricing on up to 50% of current production for the next 12 months and up to 25% for 13 to 24 months forward (future production growth is not hedged). The current hedge position is shown below (excludes price differential contracts which are shown in the financial statements) and protects approximately 16% of forecast production for 2020.

H1 2020	Crude Oil	900 Bpd	WTI Cdn$70.89/Bbl floor, Cdn$80.89 ceiling
		750 Bpd	WTI Cdn$71.92/Bbl
	Natural Gas	20,000 Mmbtu/d (17.2 Mmcf/d)	Chicago Cdn$3.32/Mmbtu
		1,000 Mmbtu/d (0.9 Mmcf/d)	NYMEX US$2.60/Mmbtu floor, $3.11 ceiling
		1,000 Mmbtu/d (0.9 Mmcf/d)	NYMEX US$2.41/Mmbtu
		3,500 Mmbtu/d (3.0 Mmcf/d)	Sumas Cdn$3.94/Mmbtu
		750 GJ/d (0.6 Mmcf/d)	AECO Cdn$2.00/GJ
		2,500 GJ/d (2.0 Mmcf/d)	AECO Cdn$1.77/GJ floor, $2.28 ceiling
		10,000 GJ/d (8.2 Mmcf/d)	Station 2 Cdn$1.77/GJ
H2 2020	Crude Oil	400 Bpd	WTI Cdn$68.38/Bbl floor, Cdn$79.01 ceiling
		400 Bpd	WTI Cdn$71.16/Bbl
	Natural Gas	1,500 Mmbtu/d (1.3 Mmcf/d)	Chicago Cdn$3.34/Mmbtu
		2,000 Mmbtu/d (1.7 Mmcf/d)	NYMEX US$2.47/Mmbtu
		2,300 GJ/d (1.9 Mmcf/d)	Station 2 Cdn$1.48/GJ

OUTLOOK

Production in the first quarter of 2020 is forecast to average 24,000 to 25,000 Boe per day with capital investment estimated to be $30 million (approximately 40% allocated to the Nig Gas Plant project).

Updated guidance for 2020 is provided below. Forecast production includes incremental production from the Nig gas Plant which started up in late February 2020 and the effect of a planned 25-day maintenance outage at the McMahon Gas Plant in September 2020. First production from the Fireweed area is expected in late 2020 or early 2021 depending on the timing to construct infrastructure. Forecast pricing reflects actual prices to date plus the approximate forward strip for the remainder of the year. Capital investment is intended to be approximately equal to funds flow. Investment in the first half of the year is expected to be approximately $31 million and is largely committed at this point. Capital investment for the second half of the year will be reviewed mid-year and may be adjusted depending on commodity prices and forecast funds flow.

2020 Guidance

	Initial November 12, 2019	Current February 27, 2020
Cdn$/US$ exchange rate	0.76	0.76
Chicago daily natural gas - US$/Mmbtu	$2.45	$1.90
Sumas monthly natural gas - US$/Mmbtu	not provided	$1.90
AECO daily natural gas - Cdn$/GJ	$1.85	$1.75
Station 2 daily natural gas - Cdn$/GJ	$1.60	$1.65
WTI - US$/Bbl	$54.00	$50.50
Edmonton condensate diff - US$/Bbl	($5.00)	($4.00)
Est revenue net of transport (excl hedges) - $/Boe	not provided	$13.50 - $13.75
Est operating costs - $/Boe	not provided	$4.50 - $4.75
Est royalty rate (% revenue net transportation)	not provided	5% - 7%
Est mid-point field operating netback - $/Boe	not provided	$8.20
Est hedging gains or (losses) - $ million	not provided	$5.0 - $6.0
Est cash G&A - $ million	not provided	$6.0 - $7.0
Est interest expense - $ million	not provided	$7.0 - $8.0
Est capital investment (excluding A&D) - $ million	$75.0 - $90.0 (Nig GP $5.0 million)	$75.0 - $85.0 (Nig GP $14.0 million)
Forecast fourth quarter Boe/d	27,000 - 30,000	25,000 - 30,000
Forecast fourth quarter liquids Bbls/d	5,700 - 6,300	5,300 - 6,300
Forecast annual Boe/d	24,000 - 26,000	23,500 - 26,000
Forecast annual liquids Bbls/d	not provided	4,900 - 5,500
Est annual funds flow - $ million	not provided	$62 - $69(1)
Horizontal wells drilled - gross	8 - 12 (6.0 - 8.0 net)	6 - 10 (4.0 - 8.5 net)
Horizontal wells completed - gross	6 - 14 (4.5 - 10.5 net)	8 - 10 (6.5 - 8.5 net)
Horizontal wells starting production - gross	not provided	5 - 10 (5.0 net - 8.5 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.

The majority of estimated capital investment in 2020 is being directed to growth from the Nig and Fireweed areas:

- $36 million at Fireweed includes constructing a 50 Mmcf per day field compression facility (50% working interest), drilling four horizontal wells (2.0 net) and completing three wells (1.5 net);

- $28 to $38 million at Nig includes $14 million to complete the gas plant (100% working interest), drilling two to four horizontal wells (2.0 to 4.0 net) and completing and pipeline connecting two to four wells (2.0 to 4.0 net); and
- $11 million at Umbach includes completing and pipeline connecting three horizontal wells (3.0 net).

Firm pipeline transportation contracts in 2020 total approximately 115 Mmcf per day with 50% directed to Chicago, 16% to BC Station 2, 12% to AECO, 12% to Alliance ATP and 10% to Sumas. Production exceeding firm contracts will generally be sold at Station 2 using interruptible capacity. Approximately 60% of forecast natural gas production in 2020 will be sold into US markets and the remaining 40% in Western Canadian markets.

Natural gas prices at AECO and Station 2 have improved since last September as a result of declining supply and low storage levels. In addition, the AECO – Station 2 price differential has improved to average -$0.09 per GJ to date in 2020 (versus -$0.70 per GJ in 2019) as a result of restoring capacity on the Enbridge T-south pipeline in late November 2019 after the completion of repairs and inspections following a failure in October 2018. Also helping the differential is the start-up of the TC Energy North Montney extension on January 31st which will ultimately increase exports from NE BC by up to 1.5 Bcf per day (contracted capacity). Although the pricing outlook has become more optimistic, that could reverse if supply growth restarts given the loss of market share in eastern markets (lower AECO price is required to incentivise higher exports from Western Canada to eastern markets).

Storm's NGL price is expected to improve in 2020 based on indications for contracted plant gate pricing for butane and propane for the next contract year which starts in April. The NGL price during the current contract period (April 2019 to March 2020) has averaged approximately 7% of WTI versus 42% of WTI in the previous contract period (April 2018 to March 2019). This reduced 2019 funds flow by approximately $10 million. Using the current forward strip, the price is expected to improve to approximately 20% of WTI for the next contract period (April 2020 to March 2021). Also contributing to the lower NGL price in 2019 was weaker North American propane prices (Conway averaged US$0.47 per gallon in 2019 versus US$0.72 in 2018 and is currently approximately US$0.40).

The near-term growth plan is expected to increase liquids as a proportion of total production and decrease per-Boe operating costs. Depending on capital investment and the number of wells drilled and completed in 2020, production is forecast to grow to 25,000 to 30,000 Boe per day by the fourth quarter of 2020. At the mid-point, the year-over-year increase in fourth quarter total production is forecast to be 23% with liquids production increasing by 36%. The start of production from Fireweed in late 2020 or early 2021 will further increase liquids production as a proportion of total production. With capital investment intended to be approximately equal to funds flow, investment may be adjusted depending on commodity prices which would change the timing for growth.

Over the last three years, funds flow per share has been largely unchanged as a result of declining commodity prices, however, production has grown by 26% per share, PDP reserves have grown by 28% per share, the PDP recycle ratio has averaged 1.6 using the funds flow netback, and annual return on capital employed has been between 4% and 10%. Capital investment decisions will continue to emphasize both per-share growth along with a return on invested capital.

The business plan continues to focus on increasing asset value per share by converting resource into per-share growth of funds flow and reserves value. This has been challenging in the current price environment where commodity prices have been volatile and have trended lower over the last several years. Success in this environment is expected to continue being dependent on improving capital efficiencies (better wells for the same or lower cost) and finding ways to offset the effect of declining commodity prices (reducing production costs and/or increasing liquids production to increase revenue). With 2P reserves recognized only in the upper Montney on approximately 25% of the total land position, there remains significant longer-term upside.

I appreciate the considerable and relentless efforts of Storm's employees and the advice, guidance and support of the Board of Directors which have both been invaluable to Storm's success to date.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 27, 2020

RESERVES AT DECEMBER 31, 2019

Storm's year-end reserve evaluation effective December 31, 2019 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 20, 2020. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2019 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, 2019 (the "AIF").

Summary

- Proved developed producing reserves ("PDP") increased to 43,322 Mboe during 2019, a 3% increase over the 2018 year-end PDP reserves of 42,204 Mboe. Total proved reserves ("1P") increased to 156,118 Mboe, a 4% increase over 2018 year-end 1P reserves of 149,905 Mboe. Total proved plus probable reserves ("2P") increased to 195,482 Mboe, a 7% increase over 2018 year-end 2P reserves of 182,370 Mboe.

- Reserve additions in 2019 replaced 115% of production for PDP reserves, 185% for 1P reserves and 278% for 2P reserves.

- Technical revisions increased PDP reserves by 1,768 Mboe (4%), 1P reserves by 981 Mboe (1%) and reduced 2P reserves by 771 Mboe (0%). Revisions were primarily due to well performance exceeding the InSite forecast from the previous year.

- 2P reserves include 937 Bcf of natural gas and 39 Mmbbl of NGL at year-end 2019. The NGL component includes 52% condensate (20 Mmbbl), 24% butane (9 Mmbbl) and 24% propane (9 Mmbbl).

- Breaking down 2P reserves by area, 74% is at Umbach and 26% is at Nig. There were no reserves assigned to the Fireweed area (all categories).

- The all-in finding, development and acquisition ("FD&A") cost(1) to add reserves was $11.43 per Boe for PDP, $3.90 per Boe for 1P and $3.16 per Boe for 2P.

- Future development costs ("FDC") were $642 million for 1P and $675 million for 2P and are fully financed from forecast cash flow within four years which complies with the Canadian Oil and Gas Evaluation ("COGE") Handbook.

- FDC includes $114 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $166 million net) with $13 million to finish construction of the Nig Gas Plant and $101 million allocated to future infrastructure expansion at Nig and Umbach.

- FDC decreased from 2018 mainly as a result of investing $61 million in the Nig Gas Plant in 2019 (1P and 2P at the end of 2019 includes the remaining $13 million to finish construction of the Nig Gas Plant).

- The estimated cost to drill, complete and tie in a future Montney horizontal well at Umbach is $5.9 million which is unchanged from the previous year (versus actual cost in 2019 averaging $5.7 million).

- Wells drilled in 2019 were assigned an average of 10.5 Bcf gross raw gas on a 2P basis.

- At Umbach and Nig there are 92.6 net 2P future horizontal drills assigned an average of 8.1 Bcf gross raw gas (last year was 88.6 net 2P locations with 7.9 Bcf gross raw gas).

- At Umbach and Nig, 2P reserves were recognized in the upper Montney on 44 net sections (an increase of 2.3 net sections from last year), 1P on 42.3 net sections and PDP on 15.4 net sections. DPIIP averages 51

Bcf gross raw gas per section in the upper Montney (total net DPIIP 2.24 Tcf on 44 net sections). Forecast recovery of DPIIP totals 54% for 2P reserves.

- The full corporate decommissioning liability for all wells and facilities was included in this year's evaluation and totaled $38.3 million on an undiscounted basis. Compared to last year, this reduced the PDP Net Present Value ("NPV") by $27 million on an undiscounted basis and by $8 million when discounted at 10%. Previously, only the decommissioning liability associated with currently active wells was included (did not include inactive wells or the cost of decommissioning facilities).

- The PDP NPV discounted at 10% decreased by 16% to $399.5 million mainly as a result of lower forecast natural gas prices (approximate decrease of 15% over the first five years) plus the effect of including the full corporate decommissioning liability for all wells and facilities. Using this year's price forecast in last year's evaluation, the NPV discounted at 10% was flat year over year.

(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, 2019, 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, 2019
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	210,418	8,253	43,322
Proved non-producing	4,076	91	771
Total proved developed	214,494	8,344	44,093
Proved undeveloped	536,365	22,630	112,025
Total proved	750,859	30,974	156,118
Probable additional	186,573	8,270	39,365
Total proved plus probable	937,432	39,244	195,482

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2019
(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, 2018 – opening balance	42,204	149,905	32,464	182,370
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	6,702	12,582	8,653	21,235
Dispositions	-	-	-	-
Technical revisions	1,768	1,225	(1,642)	(417)
Economic factors	-	(244)	(110)	(354)
Production	(7,351)	(7,351)	-	(7,351)
December 31, 2019 – closing balance	43,322	156,118	39,365	195,482

Numbers in this table may not add due to rounding.

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

(Years)	2019	2018	2017
PDP	5.3	5.2	5.2
1P	19.1	18.3	14.9
2P	23.9	22.3	19.7

Future Development Costs (“FDC”)

	Proved ($M)	Proved Plus Probable ($M)
2020	85,600	85,600
2021	169,575	169,575
2022	268,735	289,044
2023	118,558	130,868
2024	-	-
Total FDC - undiscounted	642,469	675,087
Total FDC - discounted at 10%	521,619	546,292

($million)	2019	2018	2017
1P FDC	$ 642	$ 686	$ 412
2P FDC	$ 675	$ 707	$ 481

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)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,921
Total capital including change in FDC (000s)	$ 96,843	$ 83,641	$ 81,685	$ 262,169
Total reserve additions (Mboe)	8,469	15,967	14,180	38,616
All-in PDP FD&A cost (per Boe)	$ 11.43	$ 5.24	$ 5.76	$ 6.79

Total Proved FD&A Cost (All-in)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(43,992)	274,814	(1,127)	229,695
Total capital including change in FDC (000s)	$ 52,851	$ 359,577	$ 80,558	$ 492,986
Total reserve additions (Mboe)	13,563	59,780	26,366	99,709
All-in 1P FD&A cost (per Boe)	$ 3.90	$ 6.01	$ 3.06	$ 4.94

Total Proved Plus Probable FD&A Cost (All-in)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(32,089)	226,058	(42,755)	151,214
Total capital including change in FDC (000s)	$ 64,754	$ 310,821	$ 38,930	$ 414,505
Total reserve additions (Mboe)	20,464	60,899	30,617	111,980
All-in 2P FD&A cost (per Boe)	$ 3.16	$ 5.10	$ 1.27	$ 3.70

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

Total Proved F&D Cost	2019	2018	2017	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(43,992)	274,814	(1,127)	229,695
Total capital including change in FDC (000s)	$ 52,851	$ 359,577	$ 80,558	$ 492,986
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	12,582	43,347	16,669	72,598
1P F&D cost (per Boe)	$ 4.20	$ 8.30	$ 4.83	$ 6.79

Total Proved Plus Probable F&D Cost	2019	2018	2017	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(32,089)	226,058	(42,755)	151,214
Total capital including change in FDC (000s)	$ 64,754	$ 310,821	$ 38,930	$ 414,505
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	21,235	39,608	19,615	80,458
2P F&D cost (per Boe)	$ 3.05	$ 7.85	$ 1.98	$ 5.16

Net Present Value Summary (before tax) as at December 31, 2019

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	612,052	485,065	399,523	340,434	297,875
Proved non-producing	5,204	3,350	2,247	1,547	1,079
Total proved developed	617,256	488,415	401,770	341,981	298,954
Proved undeveloped	1,476,538	937,831	628,601	436,660	310,307
Total proved	2,093,794	1,426,246	1,030,371	778,641	609,261
Probable additional	825,098	425,209	248,771	159,563	109,366
Total proved plus probable	2,918,892	1,851,455	1,279,142	938,204	718,627

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2019

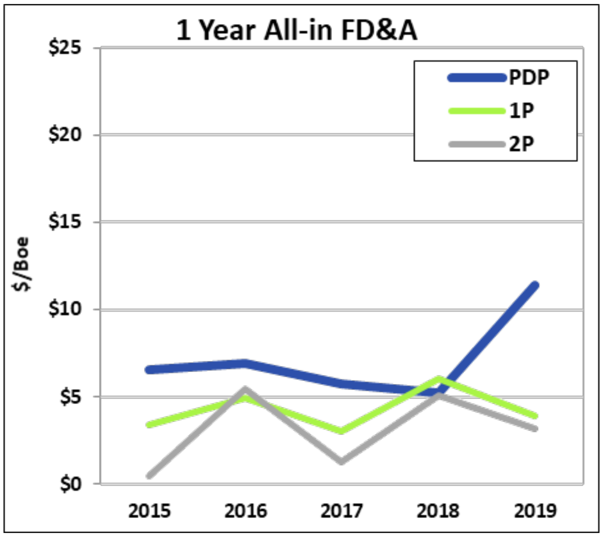
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

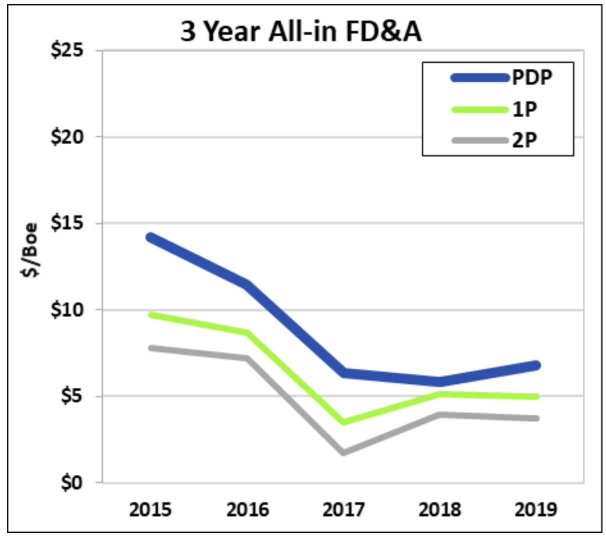
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	578,137	466,464	388,827	334,031	293,907
Proved non-producing	3,845	2,524	1,724	1,206	851
Total proved developed	581,982	468,988	390,551	335,237	294,758
Proved undeveloped	1,093,533	682,789	447,459	301,897	206,551
Total proved	1,675,515	1,151,776	838,010	637,134	501,309
Probable additional	611,458	314,275	183,243	117,062	79,880
Total proved plus probable	2,286,973	1,466,052	1,021,253	754,195	581,189

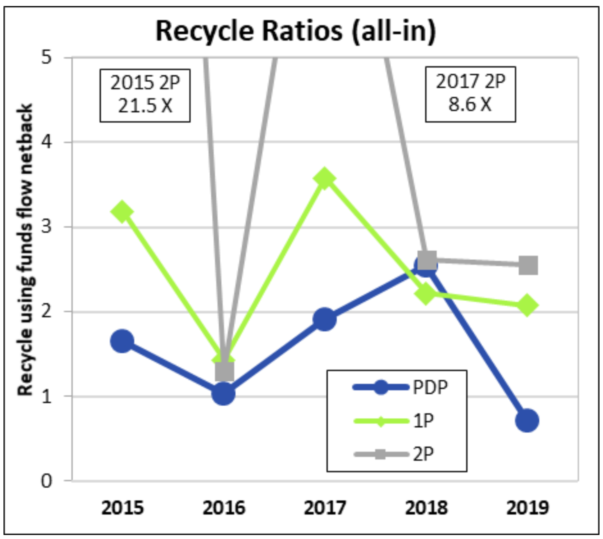
Numbers in this table may not add due to rounding.

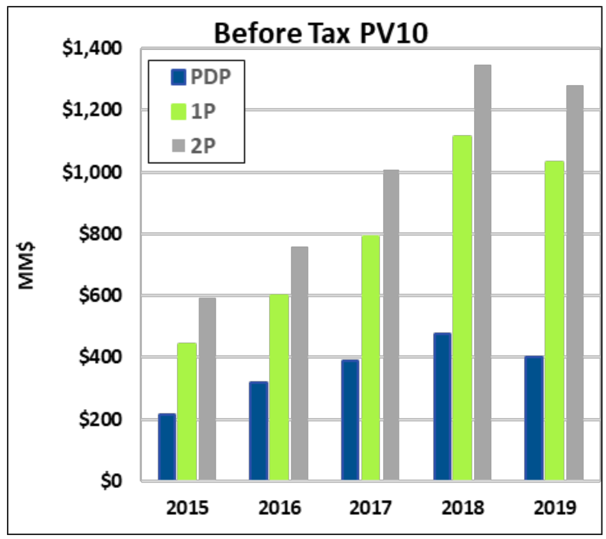
InSite Escalating Price Forecast as at December 31, 2019

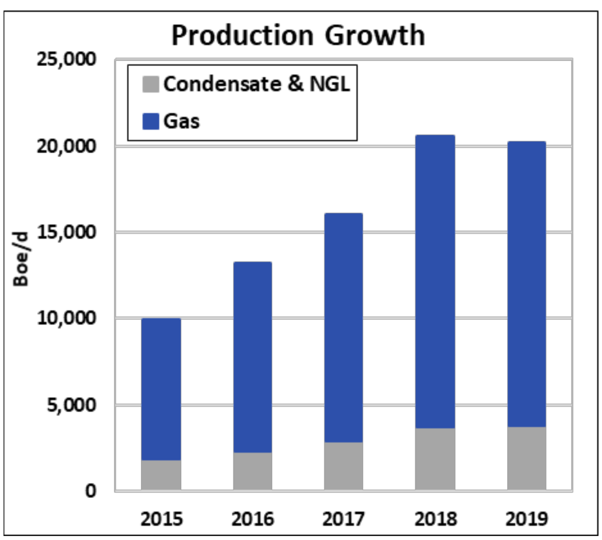
	Exchange Rate (US$/Cdn$)	WTI Crude Oil (US$/Bbl)	Condensate (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	BC Station 2 (Cdn$/Mmbtu)
2020	0.76	61.00	76.93	2.50	2.05	1.70
2021	0.77	64.50	80.22	2.75	2.32	2.02
2022	0.78	66.50	82.30	3.00	2.60	2.30
2023	0.80	68.20	84.40	3.15	2.69	2.44
2024	0.80	69.90	86.91	3.25	2.81	2.59

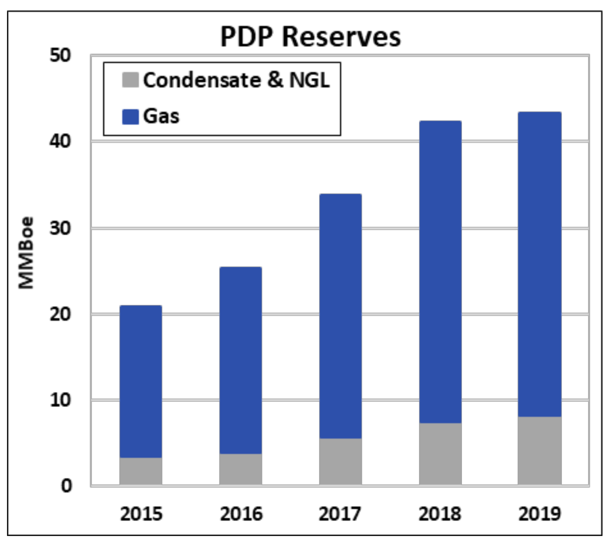

1 Year All-in FD&A
$/Boe
$25
$20
$15
$10
$5
$0
2015
2016
2017
2018
2019
PDP
1P
2P

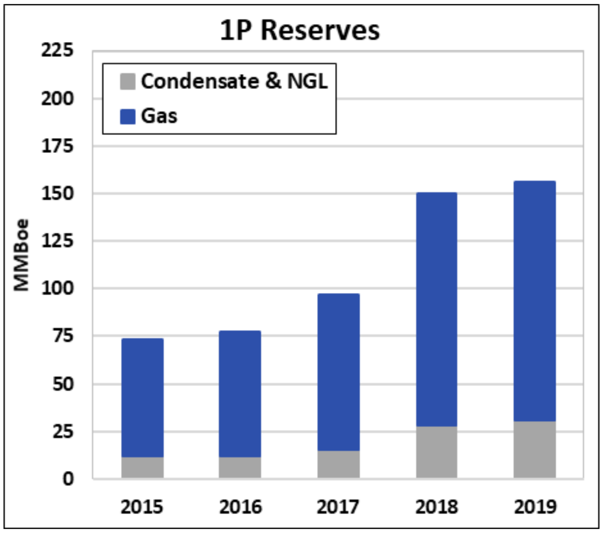

3 Year All-in FD&A
$/Boe
$25
$20
$15
$10
$5
$0
2015
2016
2017
2018
2019
PDP
1P
2P

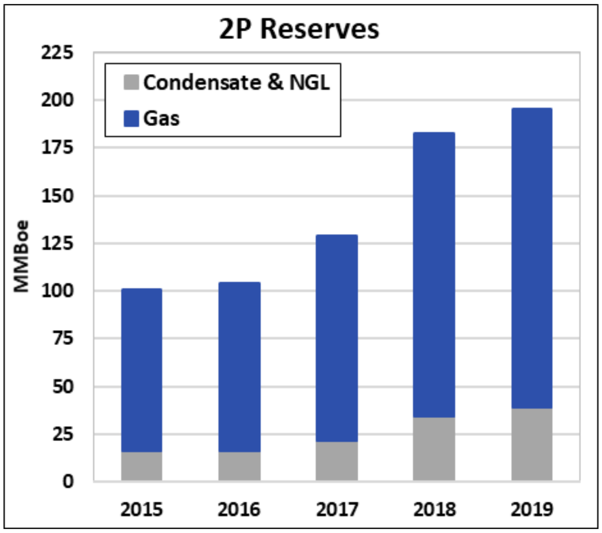

Recycle Ratios (all-in)
Recycle using funds flow netback
5
4
3
2
1
0
2015 2P
21.5 X
2017 2P
8.6 X
2015
2016
2017
2018
2019
PDP
1P
2P

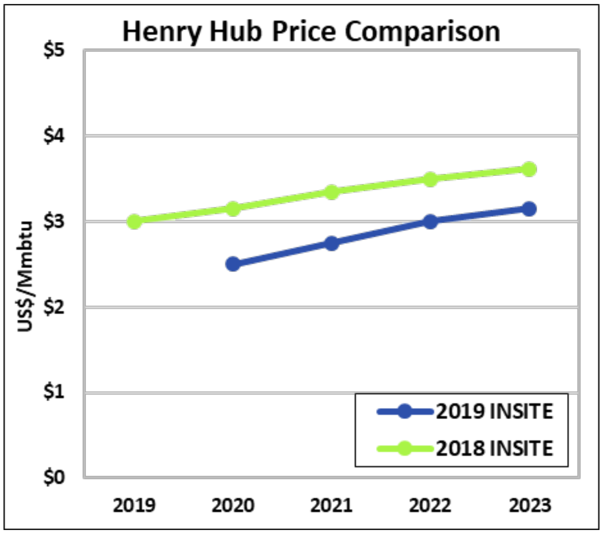

Before Tax PV10
MM$
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
PDP
1P
2P
2015
2016
2017
2018
2019

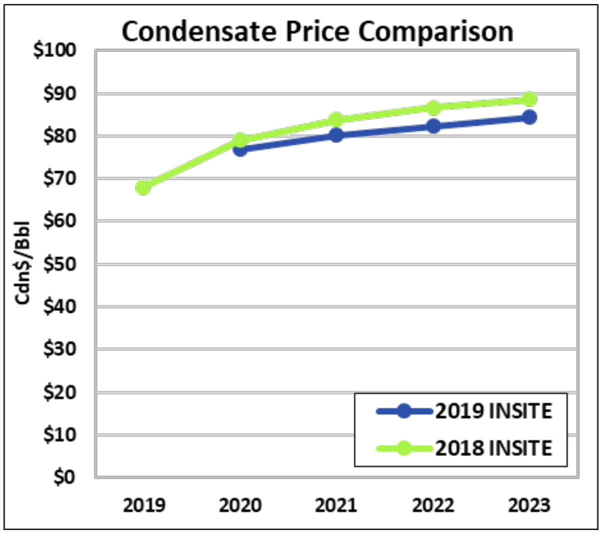

Production Growth
Boe/d
25,000
20,000
15,000
10,000
5,000
0
Condensate & NGL
Gas
2015
2016
2017
2018
2019

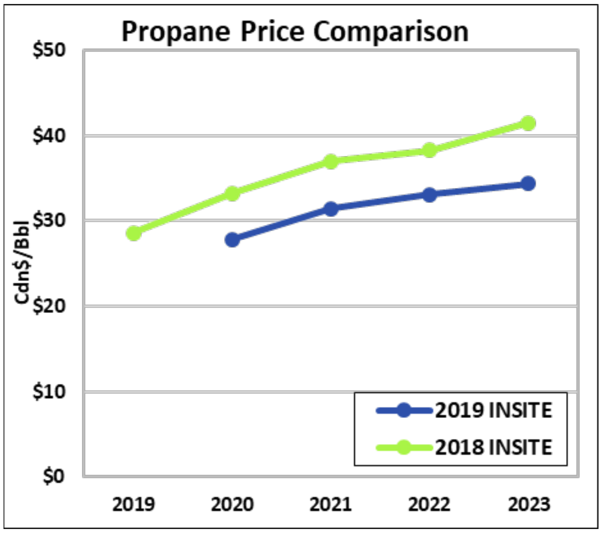

PDP Reserves
MMBoe
50
40
30
20
10
0
Condensate & NGL
Gas
2015
2016
2017
2018
2019

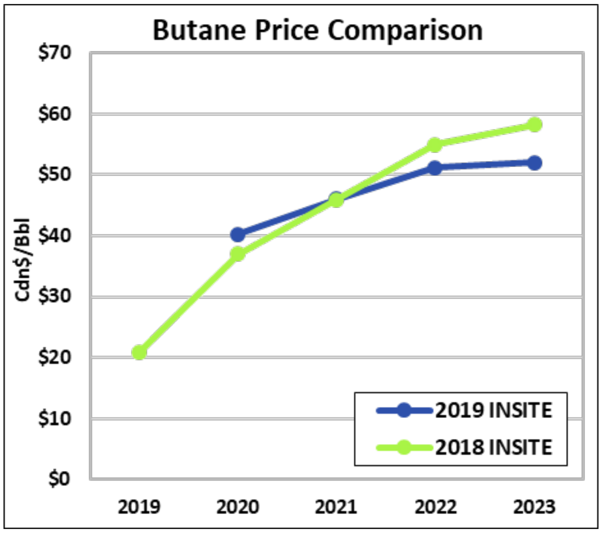

1P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2015
2016
2017
2018
2019


2P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2015
2016
2017
2018
2019


Henry Hub Price Comparison
US$/Mmbtu
$5
$4
$3
$2
$1
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Condensate Price Comparison
Cdn$/Bbl
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Propane Price Comparison
Cdn$/Bbl
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Butane Price Comparison
Cdn$/Bbl
$70
$60
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023

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 27, 2020 for the period ended December 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 February 27, 2020 for the period ended December 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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