STORM RESOURCES

NEWS RELEASE

March 2, 2021
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, 2020

Storm has also filed its audited consolidated financial statements as at December 31, 2020 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, 2020, as well as reserves information at December 31, 2020, appears below and should be read in conjunction with the related financial statements and MD&A.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Dec. 31, 2020	Three Months to Dec. 31, 2019	Year Ended Dec. 31, 2020	Year Ended Dec. 31, 2019
FINANCIAL				
Revenue from product sales(1)	52,941	48,671	155,065	173,422
Funds flow	22,350	18,469	56,824	59,549
Per share - basic and diluted ($)	0.18	0.15	0.47	0.49
Net income (loss)	17,873	2,906	(214)	11,313
Per share - basic and diluted ($)	0.15	0.02	(0.00)	0.09
Cash return on capital employed ("CROCE")(2)	12%	12%	12%	12%
Return on capital employed ("ROCE")(2)(4)	2%	4%	2%	4%
Capital expenditures	16,163	23,913	59,251	96,843
Debt including working capital deficiency/ surplus(2)(3)	131,705	128,901	131,705	128,901
Common shares (000s)				
Weighted average - basic	121,581	121,557	121,563	121,557
Weighted average - diluted	122,536	121,557	121,563	121,557
Outstanding end of period - basic	121,689	121,557	121,689	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	22.15	23.64	18.25	23.54
Transportation costs	(4.81)	(5.20)	(5.36)	(5.66)
Revenue net of transportation	17.34	18.44	12.89	17.88
Royalties	(0.92)	(1.59)	(0.78)	(1.11)
Production costs	(4.13)	(5.67)	(4.64)	(5.87)
Field operating netback(2)	12.29	11.18	7.47	10.90
Realized gain (loss) on risk management contracts	(1.09)	(0.80)	0.89	(1.20)
General and administrative	(0.67)	(0.70)	(0.74)	(0.93)
Interest and finance costs	(0.96)	(0.71)	(0.85)	(0.68)
Decommissioning expenditures	(0.22)	-	(0.08)	-
Funds flow per Boe	9.35	8.97	6.69	8.09
Barrels of oil equivalent per day (6:1)	25,985	22,375	23,219	20,182
Natural gas production				
Thousand cubic feet per day	124,927	108,679	111,776	98,458
Price (Cdn$ per Mcf)(1)	3.21	3.28	2.64	3.21
Condensate production				
Barrels per day	2,502	2,416	2,265	2,138
Price (Cdn$ per barrel)(1)	52.04	66.56	46.96	66.03
NGL production				
Barrels per day	2,662	1,846	2,325	1,634
Price (Cdn$ per barrel)(1)	16.41	6.11	9.62	10.75
Wells drilled (net)	3.0	-	8.0	6.0
Wells completed (net)	4.0	-	7.5	5.0
Wells started production (net)	4.0	4.0	7.0	7.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 38 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.
(4) Includes a non-cash unrealized loss on risk management contracts of $6.5 million for the year ended December 31, 2020 (December 31, 2019 – unrealized gain of $1.5 million).

PRESIDENT'S MESSAGE

2020 FOURTH QUARTER HIGHLIGHTS

Production benefitted from the start-up of four wells at Nig Creek in late October and cost structure continues to improve. Production costs decreased with increased volumes processed at the 100% working interest Nig Creek Gas Plant and transportation costs decreased with a higher proportion of natural gas sales into Western Canadian markets where pipeline tariffs are lower.

- Production was 25,985 Boe per day, a 37% increase from the previous quarter and a 16% increase year over year. This was consistent with guidance of 25,000 to 27,000 Boe per day.

- Liquids production (condensate plus NGL) totaled 5,164 barrels per day which was 20% of total production and 30% of total revenue. NGL production increased 44% from last year largely as a result of higher recoveries realized at the Nig Creek Gas Plant.

- At Nig Creek, sales from the gas plant averaged 9,930 Boe per day (27% increase from the previous quarter) with a production cost of $1.30 per Boe. Four new wells (4.0 net) in the upper Montney started producing in late October with the IP120 averaging 9.4 Mmcf raw per day which is 18% higher than earlier wells.

- Revenue net of transportation was $17.34 per Boe, a 6% decline from last year mainly as a result of a lower condensate price caused by the decline in the WTI crude oil price. The lower natural gas price was offset by a reduction in the transportation cost per Boe as less natural gas was sold into US markets where pipeline tariffs are higher.

- Production, general and administrative, and interest and finance costs totaled $5.76 per Boe, a year-over-year reduction of 19%. This was mainly driven by the start-up of the Nig Creek Gas Plant in February 2020 which reduced third-party processing fees and resulted in production costs per Boe declining by 27%.

- The realized hedging loss was $2.6 million, larger than the loss of $1.6 million in the previous year as a result of the rapid recovery in commodity prices in the second half of 2020.

- Funds flow was $22.4 million, or $0.18 per share, an increase of 21% from last year and the highest quarterly funds flow since the fourth quarter of 2018. This was largely the result of higher production given that lower production costs per Boe offset the decline in revenue net of transportation per Boe.

- Net income was $17.9 million and benefitted from an unrealized (non-cash) hedging gain of $14.9 million which represents the change in the value of future hedging contracts from the previous quarter.

- Capital investment was $16.2 million (versus guidance for $15 million) with the majority, or $12.5 million, directed to drilling three horizontal wells at Umbach and finishing the completions on four wells at Nig Creek.

- Total debt including working capital deficiency was $132 million which was 1.5X annualized fourth quarter funds flow. Compared to the previous quarter, this was a reduction of $6 million.

- The current commodity price hedge position protects revenue on approximately 44% of forecast production for 2021. At year end, the financial liability for future hedging contracts was $8 million.

2020 YEAR-END HIGHLIGHTS

As planned, capital investment during the year was approximately equal to funds flow which resulted in year-over-year production growth of 15% and a material improvement in the cost structure.

- Production averaged 23,219 Boe per day, a 15% increase from the previous year although this ended up being below initial guidance provided in November 2019 (24,000 to 26,000 Boe per day) as a result of reducing capital investment in May 2020 in response to lower commodity prices.

- The realized natural gas price at $2.64 per Mcf was higher than Western Canadian pricing (AECO daily index $2.11 per GJ and Station 2 $2.07 per GJ) as a result of diversified sales with 62% of sales into US markets.

- During 2020, seven horizontal wells started production and contributed approximately 2,850 Boe per day to average annual production and 7,160 Boe per day to fourth quarter production. Based on the fourth quarter addition, the implied corporate decline rate from Q4/19 to Q4/20 was 16%.

- Production, general and administrative, and interest and finance costs were $6.23 per Boe, a 17% decrease from the previous year which was mainly from the start-up of the Nig Creek Gas Plant which reduced production costs to $4.64 per Boe from $5.87 per Boe in 2019.

- The realized hedging gain was $8 million, a reversal from the previous year's loss of $9 million mainly as a result of gains realized from WTI crude oil price hedges.

- Funds flow was $57 million ($6.69 per Boe), a decline of 5% from the previous year with 15% production growth being more than offset by a large 22% reduction in revenue per Boe caused by lower condensate and natural gas prices.

- Net income was effectively nil ($0.00 per share) as compared to $11 million in the previous year with the decrease caused by a large decline in revenue and a reversal in the unrealized (non-cash) hedging gain or loss from a gain of $2 million in 2019 to a loss of $7 million in 2020.

- Capital investment was $59 million which included $12 million to complete the Nig Creek Gas Plant and $37 million to drill nine wells (8.0 net) and complete eight wells (7.5 net).

- Drilling plus completion costs at Umbach and Nig Creek averaged $4.5 million per well, a reduction of 18% from last year mainly as a result of both lower service costs and modifications to the wellbore design to increase pumping rates during fracture stimulation (well length was unchanged).

- Return on capital employed (ROCE) was 2% and cash return on capital employed (CROCE) was 12%. ROCE includes the effect of non-cash hedging gains or losses which can make it less meaningful as a way of measuring return on capital.

- Carbon taxes paid to the BC government which are included in production costs, totaled $5.6 million (direct and indirect), a decrease of $0.1 million from 2019.

- Fugitive emissions are estimated to total 2,187 tonnes CO_2e from all of Storm's facilities and well sites based on the first survey that was completed in mid-2020 as part of complying with the BC Greenhouse Gas Industrial Reporting and Control Act which requires an independent party to determine emissions which are then audited/certified by an another independent party. This is approximately 1% of Storm's total direct and indirect GHG emissions in 2019. Low fugitive emissions are the result of all well sites being equipped with solar panels to operate controllers while Storm's facilities rely on compressed air to operate controllers with overhead vapors captured from all storage tanks. More details are available in the Environmental Performance section on Storm's website (under the Corporate Responsibility tab).

RESERVE EVALUATION HIGHLIGHTS

Increases in all reserves categories in 2020 were largely the result of step-out wells drilled and completed during the year, start-up of the Nig Creek Gas Plant, and positive technical revisions for well performance exceeding forecasts.

Reserves

	YOY Increase	2020	2019	2018
Proved Developed Producing (“PDP”) (MBoe)	+13%	49,134	43,322	42,204
Total Proved (“1P”) (Mboe)	+3%	160,496	156,118	149,905
Total Proved plus Probable (“2P”) (MBoe)	+2%	199,077	195,483	182,370
PDP as % of 2P		25%	22%	23%
1P as a % of 2P		81%	80%	82%
Reserve Life Index	PDP	5.2	5.3	5.2
using fourth quarter production (years)	1P	16.9	19.1	18.3
	2P	21.0	23.9	22.3

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

	2020	2019	2018	3-Year Total
PDP ($/Boe)	$4.14	$11.43	$5.24	$6.19
1P ($/Boe)	$4.16	$3.90	$6.01	$5.41
2P ($/Boe)	$5.07	$3.16	$5.10	$4.68

Recycle Ratio Using All-in FD&A Cost

	2020	2019	2018	3-Year Total
Funds Flow (000s)	$56,824	$59,549	$100,092	$216,465
Funds Flow Netback ($/Boe)	$6.69	$8.09	$13.34	$9.27
PDP Recycle	1.6	0.7	2.5	1.5
1P Recycle	1.6	2.1	2.2	1.7
2P Recycle	1.3	2.6	2.6	2.0

- Three year total PDP FD&A at $6.19 per Boe includes $84 million invested in 2018 to 2020 for the Nig Creek Gas Plant project and is representative of full-cycle costs including infrastructure.

- PDP additions totaled 14,295 Mboe and largely came from seven new step-out wells plus the start-up of the Nig Creek Gas Plant.

- Reserve additions replaced 169% of annual production for PDP, 152% for 1P and 142% for 2P.

- On a per-share basis, PDP reserves increased by 13%, 1P increased by 3% and 2P increased by 2%.

- Material future upside remains in the Montney given that PDP and 2P reserves are recognized on 18.5 and 46.7 net sections which is approximately 11% and 27%, respectively, of the total Montney land position.

OPERATIONS REVIEW

Umbach, Nig Creek and Fireweed Areas of Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and totals approximately 120,000 net acres (170 net sections) with 87 horizontal wells (81.9 net) drilled to the end of the fourth quarter.

Field activity in the fourth quarter included drilling three wells (3.0 net) at Umbach and finishing the completions and pipeline connections for four wells (4.0 net) at Nig Creek.

First quarter 2021 activity at Umbach will include completing and pipeline connecting three wells (3.0 net) and, at Fireweed, will include drilling three wells (1.5 net) plus constructing 19 kilometres of large diameter gathering and sales pipelines.

At the end of the fourth quarter, there were seven Montney horizontal wells (5.5 net) that had not started producing which included four wells (4.0 net) at Umbach and three wells (1.5 net) at Fireweed.

At Umbach (average 90% working interest), produced raw natural gas contains 1.2% H_2S with field compression capacity totaling 150 Mmcf raw per day. Firm processing commitments total 80 Mmcf raw per day (65 Mmcf per day at McMahon Gas Plant and 15 Mmcf per day at Stoddart Gas Plant). Inlet volumes in the fourth quarter averaged 88 Mmcf per day. Activity in 2021 is expected to maintain production and includes drilling the remaining three wells (3.0 net) on a six-well pad and completing six wells (6.0 net) with three completions in Q1 and three completions in Q4.

At Nig Creek (100% working interest), produced raw natural gas contains up to 0.5% H_2S and is directed to the 100% working interest sour gas plant that started up in February 2020. Gas plant inlet volumes in the fourth quarter averaged 50 Mmcf per day, sales were 9,930 Boe per day (46.2 Mmcf per day sales with total liquids of 48 barrels per Mmcf sales), and the production cost was $1.30 per Boe. Capacity of the gas plant is estimated to be 70 Mmcf raw per day at the current average H_2S of 0.3% (versus design capacity of 50 Mmcf raw per day at 0.5% H_2S). Future drilling is expected to include three to four wells each year to keep the gas plant full. Activity in 2021 will be focused on increasing volumes processed at the gas plant to 70 Mmcf raw per day which will come from adding inlet compression (expected to increase rates from existing wells by 10% to 30%) and from drilling and completing three to four wells (3.0 to 4.0 net) in the lower Montney where the H_2S is below 0.1%.

Recent wells at Nig Creek continue to exceed expectations:

- The first well in the lower Montney started producing in December 2019 with the IP365 being 760 Boe per day sales with 33% liquids (180 barrels per day of condensate plus 70 barrels per day of NGL). The half-cycle cost to drill, complete and tie-in the well was $5.2 million which was paid out in approximately 13 months (cumulative field operating netback was $5.1 million to December 2020);
- The four most recent wells in the upper Montney started producing in late October 2020 with the average IP120 being 9.4 Mmcf raw per day which is an average of 1,940 Boe per day sales with 25% liquids (250 barrels per day of condensate plus 230 barrels per day of NGL).

At Fireweed (50% working interest), activity was restarted in the fourth quarter of 2020 after being deferred following the collapse in the WTI crude oil price in April 2020. Based on production history from offsetting horizontal wells, first year average field condensate-gas ratios are expected to be 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach and Nig Creek. There are currently three standing wells (1.5 net) with two completed wells (1.0 net). Activity in 2021 will include constructing a 50 Mmcf raw per day field compression facility with 19 kilometres of gathering and sales pipelines (50% working interest), drilling five wells (2.5 net), and completing three wells (1.5 net). First production is expected in the fourth quarter of 2021 from five wells (2.5 net).

HEDGING

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

	2021	2022
Natural Gas Hedges		
% Current Nat Gas Production(1)	48%	18%
Collars	9,200 Mcf/d(2) Floor Cdn$3.44 per Mcf(3) Ceiling Cdn$4.10 per Mcf(3)	5,700 Mcf/d(2) Floor Cdn$3.77 per Mcf(3) Ceiling Cdn$4.71 per Mcf(3)
Fixed Price	51,200 Mcf/d(2) Cdn$3.17 per Mcf(3)	16,500 Mcf/d(2) Cdn$3.41 per Mcf(3)
Crude Oil Hedges		
% Current Liquids Production(1)	41%	11%
Collars	1,100 Bpd Floor WTI Cdn$52.44 per barrel(3) Ceiling WTI Cdn$62.56 per barrel(3)	400 Bpd Floor WTI Cdn$58.11 per barrel(3) Ceiling WTI Cdn$68.79 per barrel(3)
Fixed Price	800 Bpd WTI Cdn$53.41 per barrel 225 Bpd Propane Cdn$42.84 per barrel(3)	150 Bpd WTI Cdn$65.32 per barrel(3)

(1) Using Q4 2020 actual production.

(2) Using corporate average heat content 1.23 GJ per Mcf and 1.17 Mmbtu per Mcf.

(3) Hedges in US$ are converted using an exchange rate of Cdn$1.27 per US$1.

OUTLOOK

Production in the first quarter of 2021 is forecast to average 25,000 to 27,000 Boe per day while capital investment is estimated to be $25 million (approximately 45% allocated to the Fireweed area). Capital investment includes $4 million for equipment deposits related to the Fireweed facility and for inlet compression at the Nig Creek Gas Plant.

First quarter natural gas prices will benefit from elevated spot prices that were realized in February. Approximately 60% of corporate sales are at the daily index or spot price which included 26 Mmcf per day (30,000 Mmbtu per day) of sales at Chicago in February at an average of approximately US$14 per Mmbtu.

Updated guidance for 2021 is provided below. Forecast pricing is updated to reflect estimated prices to the end of the first quarter with prices for the remainder of the year being unchanged from previous guidance except for the WTI price which was increased to US$50 per barrel from US$40.

2021 Guidance

	Initial November 10, 2020	Current March 2, 2021
Cdn$/US$ exchange rate	0.76	0.79
Chicago daily natural gas - US$/Mmbtu(1)	$2.65	$3.50
AECO daily natural gas - Cdn$/GJ(1)	$2.50	$2.60
BC Station 2 daily natural gas - Cdn$/GJ	$2.50	$2.55
WTI - US$/Bbl	$40.00	$51.00
Edmonton condensate diff - US$/Bbl	($3.00)	($2.25)
Est transportation cost - $/Boe	not provided	$4.50 - $4.75
Est revenue net of transport (excl hedges) - $/Boe	$17.00 - $18.00	$19.50 - $20.50
Est royalty rate (% revenue net transportation)	7% - 8%	8% - 9%
Est production cost - $/Boe	$4.00 - $4.50	$4.00 - $4.50
Est mid-point field operating netback - $/Boe(2)	$11.95	$14.05
Est realized hedging gains or (losses) - $ million	($8.0 - $10.0)	($10.0 - $12.0)
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $7.0
Est interest expense - $ million	$7.0 - $8.0	$6.0 - $7.0
Est capital investment (excluding A&D) - $ million	$85.0 - $90.0	$85.0 - $90.0
Forecast fourth quarter Boe/d	30,000 - 32,000	30,000 - 32,000
Forecast fourth quarter liquids Bbls/d	6,800 - 7,300	6,800 - 7,300
Forecast annual Boe/d	26,000 - 28,000	26,000 - 28,000
Forecast annual liquids Bbls/d	5,600 - 6,000	5,600 - 6,000
Est annual funds flow - $ million(3)	$90.0 - $99.0	$109.0 - $120.0
Horizontal wells drilled - gross	11 (9.0 net)	11 - 12 (8.5 - 9.5 net)
Horizontal wells completed - gross	11 (10.0 net)	11 - 12 (10.5 - 11.5 net)
Horizontal wells starting production - gross	13 (11.0 net)	14 - 15 (11.5 - 12.5 net)

(1) Approximately 50% of natural gas sales are at the daily or spot price and 50% at the monthly index price.

(2) Based on the mid-point for each of revenue net of transportation, royalty rate and production costs.

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

2021 Guidance History

	Chicago Daily (US$/Mmbtu)	BC Station 2 Daily (Cdn$/GJ)	WTI (US$/Bbl)	Capital Investment ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 10, 2020	$2.65	$2.50	$40.00	$85.0 - $90.0	$90.0 - $99.0	26,000 - 28,000
Mar 2, 2021	$3.50	$2.55	$51.00	$85.0 - $90.0	$109.0 - $120.0	26,000 - 28,000

Total capital investment in 2021 is unchanged from previous guidance at $85 to $90 million with approximately 40% invested in the first half of the year. This is expected to increase average annual production by 16% (using mid-point of guidance) and will result in further reductions to the cost structure.

	Total Investment ($million)	Infrastructure ($million)	Net Wells Drilled	Net Wells Completed	Net Wells Starting Production
Fireweed	$30 - $35	$19	2.5	1.5	2.5
Nig Creek	$28	$7	3.0 - 4.0	3.0 - 4.0	3.0 - 4.0
Umbach	$27		3.0	6.0	6.0
Total	$85 - $90				

Based on forecast production, natural gas sales into Canadian markets will increase from approximately 35% in 2020 to 54% in 2021. The sales split in 2021 is expected to be 46% at Chicago, 36% at BC Station 2, 11% at AECO and 7% at Alliance ATP. The natural gas marketing strategy will continue to be based on diversifying sales as much as possible to mitigate regional price differences caused by supply/demand imbalances that are difficult to predict in terms of timing and duration. Diversification also includes an approximate 50/50 split between sales at daily spot pricing and at monthly index pricing (price is set at the start of each month).

NGL prices net of transportation for 2021 are expected to show a modest increase to 20% to 25% of WTI Cdn$ from 18% in 2020. Although marketing deductions which reflect the transportation cost to sales hubs are expected to increase for the next contract year (April 2021 to March 2022), this is expected to be offset by higher propane and butane pricing.

Cost structure on a per-Boe basis is expected to show further improvement in 2021 as production costs decline with rising throughput at the Nig Creek Gas Plant where capacity is estimated to be approximately 70 Mmcf per day and the production cost is $1.30 per Boe. In addition, transportation costs will continue to decline as a higher proportion of natural gas production is sold into Western Canadian markets which have lower pipeline tariffs.

Development at Fireweed is progressing with activity in the first quarter including drilling three horizontal wells, constructing 19 kilometers of large diameter gathering and sales pipelines, and ordering major equipment for the facility. First production of approximately 2,500 Boe per day net is expected in the fourth quarter of 2021.

The focus continues to be on growing asset value and funds flow per share. Near term (2021 to 2022), this is expected to come from:

1) Filling the Nig Creek Gas Plant where the production cost is $1.30 per Boe and liquids recovery is higher; and
2) Development at Fireweed where condensate is expected to be a higher proportion of total production.

'Free cash flow' in 2021 is estimated to be approximately $80 million using the mid-point for estimated annual funds flow in guidance (based on estimated capital investment required to maintain production being $33 million to drill, complete and tie-in 6.0 net wells). This will be directed to development at Fireweed ($30 to $35 million), growth from Umbach and Nig Creek ($22 million to drill and complete three wells plus install inlet compression), with the remainder initially used to reduce debt which increases financial flexibility. As always, capital investment will remain flexible and may be adjusted up or down depending on commodity prices.

The considerable efforts of everyone at Storm are much appreciated, especially over the last year which was complicated by having to manage the impacts of the COVID-19 pandemic at work and in everyone's personal lives. In addition, the advice, guidance and, most of all, the support of the Board of Directors has been invaluable.

We look forward to reporting on our progress during 2021 which is currently benefitting from a 'tailwind' with improving commodity prices.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

March 2, 2021

RESERVES AT DECEMBER 31, 2020

Storm's year-end reserve evaluation effective December 31, 2020 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 23, 2021. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2020 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, 2020 (the "AIF").

Summary

- Proved developed producing reserves ("PDP") increased to 49,134 Mboe during 2020, a 13% increase over the 2019 year-end PDP reserves of 43,322 Mboe. Total proved reserves ("1P") increased to 160,496 Mboe, a 3% increase over 2019 year-end 1P reserves of 156,118 Mboe. Total proved plus probable reserves ("2P") increased to 199,077 Mboe, a 2% increase over 2019 year-end 2P reserves of 195,482 Mboe.

- Reserve additions in 2020 replaced 169% of production for PDP reserves, 152% for 1P reserves and 142% for 2P reserves.

- Technical revisions increased PDP reserves by 1,981 Mboe (5%), reduced 1P reserves by 2,214 Mboe (-1%) and reduced 2P reserves by 5,611 Mboe (-2.9%). PDP revisions are largely the result of well performance exceeding expectations while 1P and 2P revisions are largely from forecast NGL yields being reduced by 7% from last year.

- Breaking down 2P reserves by area, 69% is at Umbach, 28% is at Nig Creek and 3% is at Fireweed.

- The all-in finding, development and acquisition ("FD&A") cost[(1)] to add reserves was $4.14 per Boe for PDP, $4.16 per Boe for 1P and $5.07 per Boe for 2P.

- Future development costs ("FDC") were $637 million for 1P and $677 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. For comparison, FDC last year was $642 million for 1P and $675 million for 2P.

- FDC includes $107 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $114 million net) with $87 million allocated to future infrastructure expansion at Nig Creek and Umbach, and $20 million net for construction of a Fireweed compressor station (Storm working interest 50%).

- The estimated cost to drill and complete a future Montney horizontal well at Umbach and Nig Creek is $5.1 million compared to $5.5 million used in 2019 (versus the actual cost of $4.5 million in 2020).

- Wells drilled in 2020 were assigned an average of 11 Bcf gross raw gas on a 2P basis.

- At Umbach, Nig Creek and Fireweed there are 94.1 net 2P future horizontal drills assigned an average of 7.8 Bcf gross raw gas (last year was 86.6 net 2P locations with 8.1 Bcf gross raw gas). The reduction in gross raw gas per undeveloped drill is a function of the additional locations (9.5 net) recognized in the lower Montney at Nig Creek and upper Montney locations at Fireweed where the proportion of NGL is higher.

- Future drilling locations total 94.1 net wells including 73.6 net wells at Umbach, 17.0 net at Nig Creek and 3.5 net at Fireweed. This represents approximately five years of activity at forecast commodity prices and complies with the Canadian Oil & Gas Evaluation ("COGE") Handbook.

- Future 2P drilling locations include 6.0 net wells in the lower Montney at Nig Creek and 3.5 net wells in the upper Montney at Fireweed. Previously no future drilling locations had been recognized in either area.

- At Umbach, Nig Creek and Fireweed, 2P reserves were recognized on 46.7 net sections (an increase of 2.7 net sections from last year), 1P on 45.2 net sections and PDP on 18.5 net sections. DPIIP averages 52 Bcf gross raw gas per section in the Montney (total net DPIIP 2.43 Tcf on 46.7 net sections). Forecast recovery of DPIIP totals 52% for 2P reserves.

- The full corporate decommissioning liability for all wells and facilities was included in this year's evaluation and totaled $38.5 million on an undiscounted basis. The decommissioning liability for inactive wells totaled $10.6 million on an undiscounted basis adjusted for inflation.

- The PDP NPV discounted at 10% increased by 9% to $424.6 million mainly as a result of the 13% increase in PDP reserves. Using this year's price forecast in last year's evaluation, the NPV discounted at 10% increased 15% 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, 2020, 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, 2020
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	235,474	9,888	49,134
Proved non-producing	2,512	91	509
Total proved developed	237,986	9,979	49,643
Proved undeveloped	536,859	21,376	110,853
Total proved	774,845	31,355	160,496
Probable additional	184,797	7,782	38,582
Total proved plus probable	959,642	39,137	199,077

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2020
(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, 2019 – opening balance	43,322	156,118	39,365	195,482
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	12,314	15,077	2,617	17,695
Dispositions	-	-	-	-
Technical revisions	1,981	(2,214)	(3,397)	(5,611)
Economic factors	-	(1)	(3)	(4)
Production	(8,484)	(8,484)	-	(8,484)
December 31, 2020 – closing balance	49,134	160,496	38,582	199,077

Numbers in this table may not add due to rounding.

Reserve Life Index ("RLI") Using Fourth Quarter Production

(Years)	2020	2019	2018
PDP	5.2	5.3	5.2
1P	16.9	19.1	18.3
2P	21.0	23.9	22.3

Future Development Costs ("FDC")

	Proved ($M)	Proved Plus Probable ($M)
2021	79,738	91,588
2022	88,052	91,290
2023	152,159	157,517
2024	162,789	162,789
2025	154,008	173,925
Total FDC - undiscounted	636,745	677,109
Total FDC - discounted at 10%	491,281	522,790

($million)	2020	2019	2018
1P FDC	$ 637	$ 642	$ 686
2P FDC	$ 677	$ 675	$ 707

Note: InSite escalates capital costs at 2% per year after 2020.

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

Proved Developed Producing FD&A Cost (All-in)	2020	2019	2018	3 Year Total
Net capital investment (000s)	$ 59,251	$ 96,843	$ 84,763	$ 240,857
Total capital including change in FDC (000s)	$ 59,251	$ 96,843	$ 83,641	$ 239,735
Total reserve additions (Mboe)	14,296	8,469	15,967	38,732
All-in PDP FD&A cost (per Boe)	$ 4.14	$ 11.43	$ 5.24	$ 6.19

Total Proved FD&A Cost (All-in)	2020	2019	2018	3 Year Total
Net capital investment (000s)	$ 59,251	$ 96,843	$ 84,763	$ 240,857
Change in FDC (000s)	(5,724)	(43,992)	274,814	225,098
Total capital including change in FDC (000s)	$ 53,527	$ 52,851	$ 359,577	$ 465,955
Total reserve additions (Mboe)	12,862	13,563	59,780	86,205
All-in 1P FD&A cost (per Boe)	$ 4.16	$ 3.90	$ 6.01	$ 5.41

Total Proved Plus Probable FD&A Cost (All-in)	2020	2019	2018	3 Year Total
Net capital investment (000s)	$ 59,251	$ 96,843	$ 84,763	$ 240,857
Change in FDC (000s)	2,022	(32,089)	226,058	195,991
Total capital including change in FDC (000s)	$ 61,273	$ 64,754	$ 310,821	$ 436,848
Total reserve additions (Mboe)	12,078	20,464	60,899	93,441
All-in 2P FD&A cost (per Boe)	$ 5.07	$ 3.16	$ 5.10	$ 4.68

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

Total Proved F&D Cost	2020	2019	2018	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 59,251	$ 96,843	$ 84,763	$ 240,857
Change in FDC (000s)	(5,724)	(43,992)	274,814	225,098
Total capital including change in FDC (000s)	$ 53,527	$ 52,851	$ 359,577	$ 465,955
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	15,077	12,582	43,347	71,007
1P F&D cost (per Boe)	$ 3.55	$ 4.20	$ 8.30	$ 6.56

Total Proved Plus Probable F&D Cost	2020	2019	2018	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 59,251	$ 96,843	$ 84,763	$ 240,857
Change in FDC (000s)	2,022	(32,089)	226,058	195,991
Total capital including change in FDC (000s)	$ 61,273	$ 64,754	$ 310,821	$ 436,848
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	17,695	21,235	39,608	78,538
2P F&D cost (per Boe)	$ 3.46	$ 3.05	$ 7.85	$ 5.56

Net Present Value Summary (before tax) as at December 31, 2020

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	605,499	500,522	424,596	369,626	328,689
Proved non-producing	3,274	2,011	1,234	735	402
Total proved developed	608,773	502,533	425,830	370,361	329,091
Proved undeveloped	1,062,800	673,371	444,030	300,504	206,216
Total proved	1,671,573	1,175,904	869,860	670,866	535,307
Probable additional	586,211	314,231	187,609	121,789	84,236
Total proved plus probable	2,257,783	1,490,135	1,057,469	792,655	619,542

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2020

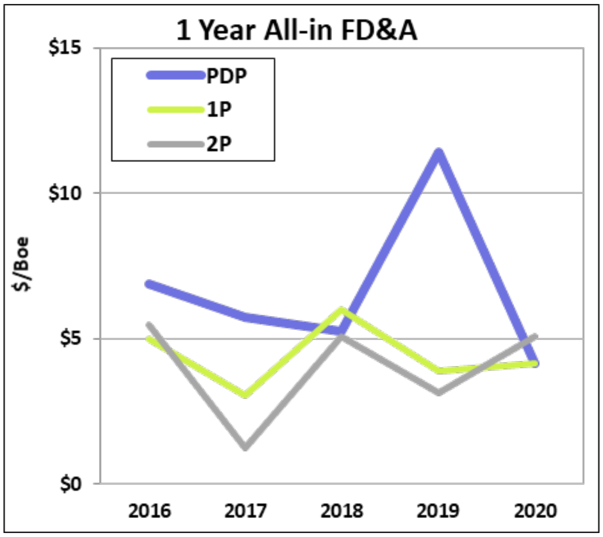
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

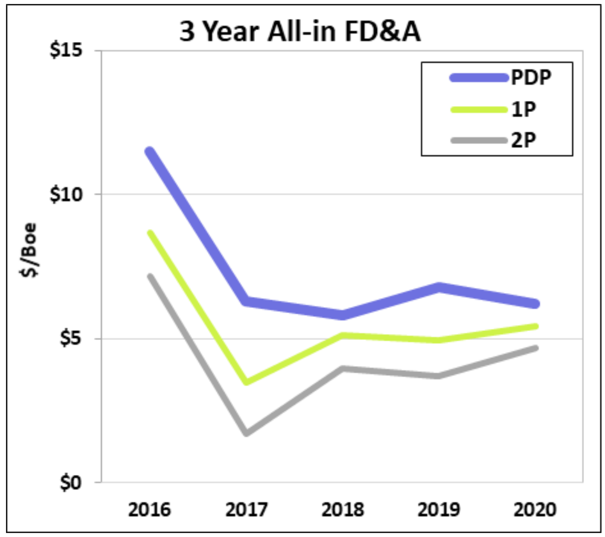
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	567,508	479,585	411,915	361,509	323,293
Proved non-producing	2,355	1,433	851	471	214
Total proved developed	569,863	481,018	412,766	361,980	323,507
Proved undeveloped	786,430	487,236	311,724	202,596	131,492
Total proved	1,356,293	968,255	724,491	564,577	455,000
Probable additional	435,636	232,832	138,381	89,396	61,528
Total proved plus probable	1,791,929	1,201,086	862,872	653,973	516,528

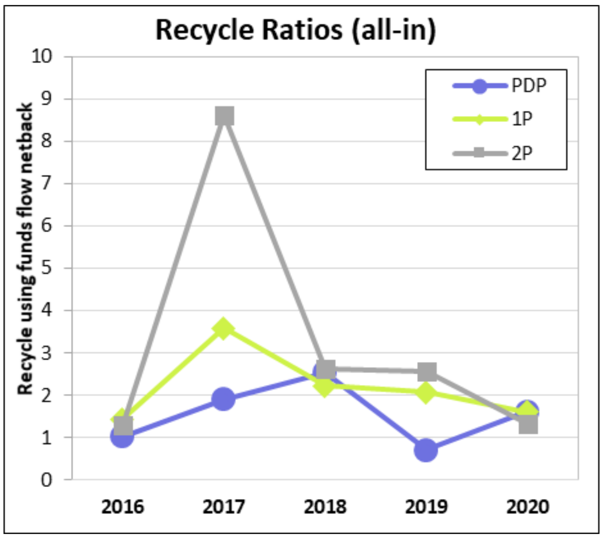
Numbers in this table may not add due to rounding.

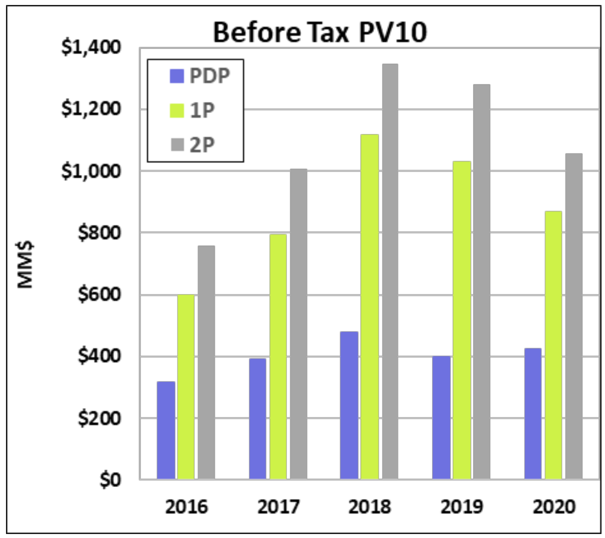
InSite Escalating Price Forecast as at December 31, 2020

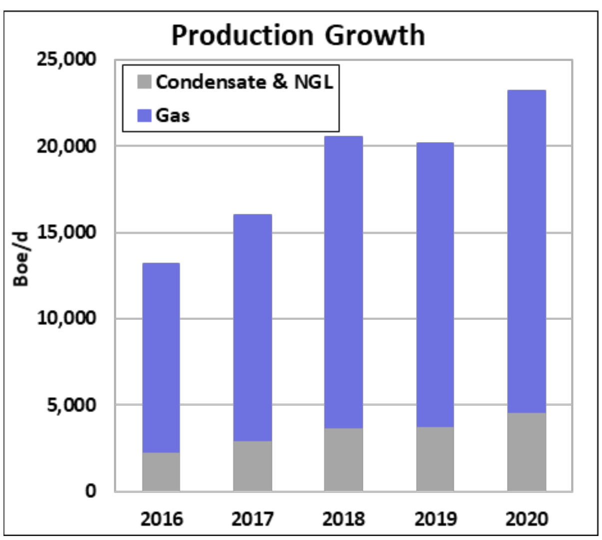
	Exchange Rate (US$/Cdn$)	WTI Crude Oil (US$/Bbl)	Condensate (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	BC Station 2 (Cdn$/Mmbtu)
2021	0.77	48.00	60.87	2.85	2.80	2.75
2022	0.77	51.00	64.56	2.91	2.71	2.66
2023	0.77	54.00	68.81	2.97	2.62	2.57
2024	0.77	55.08	70.78	3.02	2.67	2.62
2025	0.77	56.18	71.51	3.08	2.73	2.68

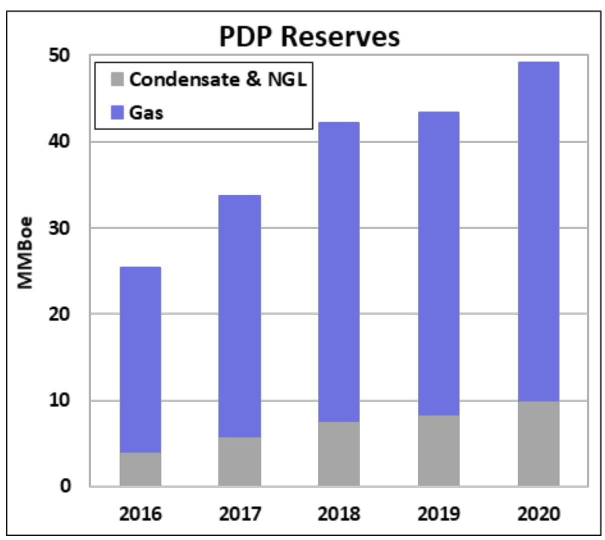

1 Year All-in FD&A
$15
$10
$5
$0
$/Boe
PDP
1P
2P
2016
2017
2018
2019
2020

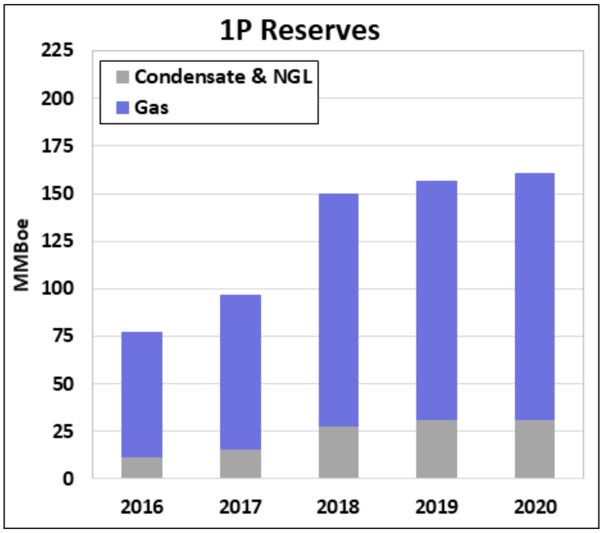

3 Year All-in FD&A
$15
$10
$5
$0
$/Boe
PDP
1P
2P
2016
2017
2018
2019
2020

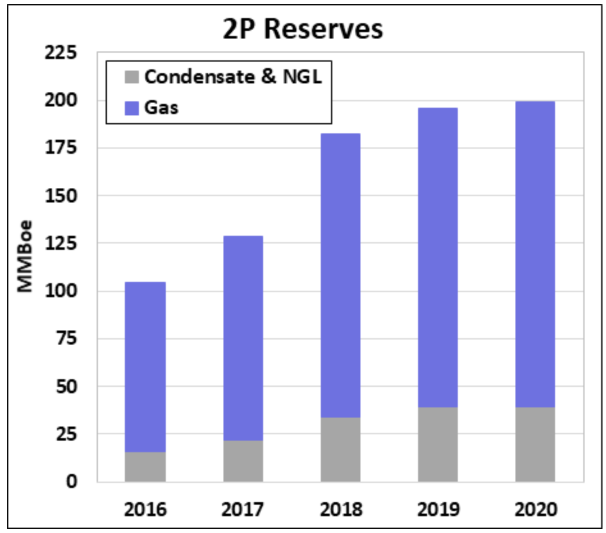

Recycle Ratios (all-in)
Recycle using funds flow netback
10
9
8
7
6
5
4
3
2
1
0
PDP
1P
2P
2016
2017
2018
2019
2020

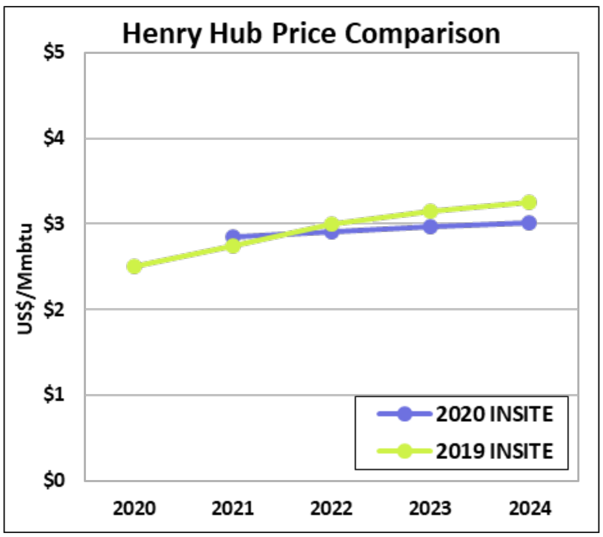

Before Tax PV10
MM$
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
PDP
1P
2P
2016
2017
2018
2019
2020

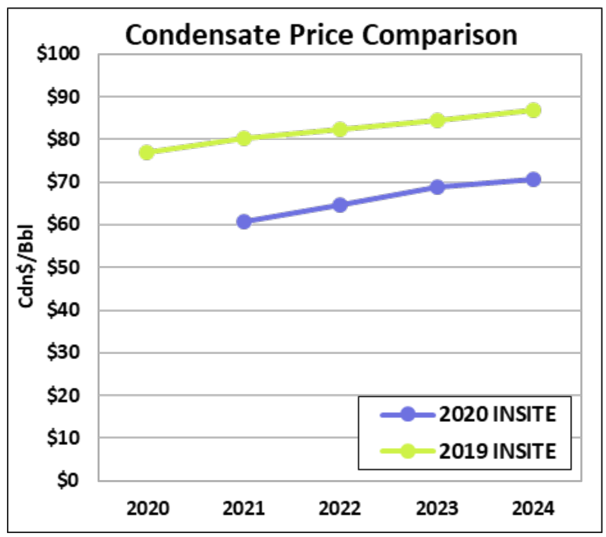

Production Growth
Boe/d
25,000
20,000
15,000
10,000
5,000
0
Condensate & NGL
Gas
2016
2017
2018
2019
2020

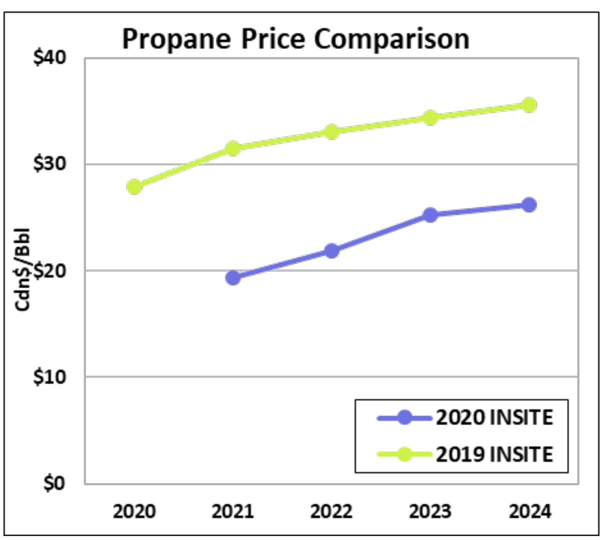

PDP Reserves
MMBoe
50
40
30
20
10
0
Condensate & NGL
Gas
2016
2017
2018
2019
2020

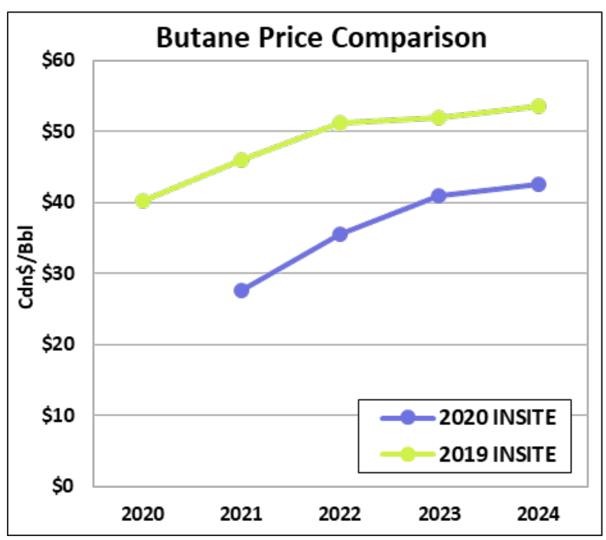

1P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2016
2017
2018
2019
2020


2P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2016
2017
2018
2019
2020


Henry Hub Price Comparison
US$/Mmbtu
$5
$4
$3
$2
$1
$0
2020
2021
2022
2023
2024
2020 INSITE
2019 INSITE


Condensate Price Comparison
Cdn$/Bbl
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
2020
2021
2022
2023
2024
2020 INSITE
2019 INSITE


Propane Price Comparison
Cdn$/Bbl
$40
$30
$20
$10
$0
2020
2021
2022
2023
2024
2020 INSITE
2019 INSITE


Butane Price Comparison
Cdn$/Bbl
$60
$50
$40
$30
$20
$10
$0
2020
2021
2022
2023
2024
2020 INSITE
2019 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 March 2, 2021 for the period ended December 31, 2020 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 30, 2020 and the MD&A dated March 2, 2021 for the period ended December 31, 2020 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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