BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2020 FINANCIAL AND OPERATING RESULTS AND YEAR END 2020 RESERVES

CALGARY, ALBERTA (February 24, 2021) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three months and year ended December 31, 2020 (all amounts are in Canadian dollars unless otherwise noted).

"In 2020, we responded aggressively to the downturn brought on by Covid-19, improved our cost structure and capital efficiencies, exceeded our GHG emissions intensity target, and enhanced our overall sustainability. The strong recovery in commodity prices in early 2021 has us on track to deliver over $250 million ($0.45 per basic share) of free cash flow in 2021. We resumed drilling activity late last year and are building significant operational momentum with current production over 78,000 boe/d. We are executing our plan to maximize free cash flow and accelerate our debt reduction strategy," commented Ed LaFehr, President and Chief Executive Officer.

2020 Highlights

- Production in line with guidance at 70,475 boe/d (82% oil and NGL) in Q4/2020 and 79,781 boe/d (82% oil and NGL) for the full-year 2020.
- Exploration and development expenditures totaled $78 million in Q4/2020, bringing aggregate spending for 2020 to $280 million, in line with guidance.
- Delivered adjusted funds flow of $82 million ($0.15 per basic share) in Q4/2020 and $312 million ($0.56 per basic share) for 2020.
- Generated free cash flow of $2 million in Q4/2020 and $18 million ($0.03 per basic share) for 2020.
- Refinanced US$500 million of long-term notes to 2027 and extended credit facility to 2024.
- Maintained undrawn credit capacity of $367 million and liquidity, net of working capital, of $319 million.
- Achieved a 46% reduction in our GHG emissions intensity through year-end 2020, relative to our 2018 baseline. This represents an annual reduction of 1.6 million tonnes of CO_2e and is equivalent to taking 340,000 cars off the road annually.
- Our net asset value at year-end 2020, discounted at 10%, is estimated to be $2.78 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

Our 2020 reserves report reflects the impact of a materially lower commodity price forecast being utilized by our reserves evaluator, which has WTI averaging US$56/bbl over the next ten years, down 20% from one year ago. At year-end 2020, proved developed producing reserves total 120 mmboe, proved reserves total 271 mmboe and our proved plus probable reserves total 462 mmboe. We removed 29 million barrels of proved reserves (65% heavy oil and bitumen) and 41 million barrels of proved plus probable reserves (80% heavy oil and bitumen), which are uneconomic using this commodity price forecast.

2021 Outlook

In 2021, we will benefit from a disciplined approach to capital allocation as well as our continued drive to improve our cost structure and capital efficiencies. Our high graded capital program is focused largely on our high netback light oil assets in the Viking and Eagle Ford. At current commodity prices, we intend to implement a heavy oil program in the second half of the year.

Our 2021 guidance remains unchanged as we target production of 73,000 to 77,000 boe/d with exploration and development expenditures of $225 to $275 million. During Q4/2020, we resumed drilling activity, which is leading to operational momentum early in 2021 with current production over 78,000 boe/d.

Based on the forward strip[(1)], we expect to generate over $250 million of free cash flow in 2021 and increase our financial liquidity to over $550 million. We have entered into hedges on approximately 48% of our net crude oil exposure for 2021, largely utilizing a 3-way option structure that provides WTI price protection at US$45/bbl with upside participation to US$52/bbl.

(1) 2021 pricing assumptions: WTI - US$58/bbl; WCS differential - US$12/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$3.00/mcf; AECO Gas - $3.05/mcf and Exchange Rate (CAD/USD) - 1.27.

	Three Months Ended			Twelve Months Ended	
	December 31, 2020	September 30, 2020	December 31, 2019	**December 31, 2020**	December 31, 2019
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 233,636**	$ 252,538	$ 445,895	**$ 975,477**	$ 1,805,919
Adjusted funds flow (1)	**82,176**	78,508	232,147	**311,506**	902,426
Per share – basic	**0.15**	0.14	0.42	**0.56**	1.62
Per share – diluted	**0.15**	0.14	0.42	**0.56**	1.62
Net income (loss)	**221,160**	(23,444)	(117,772)	**(2,438,964)**	(12,459)
Per share – basic	**0.39**	(0.04)	(0.21)	**(4.35)**	(0.02)
Per share – diluted	**0.39**	(0.04)	(0.21)	**(4.35)**	(0.02)
Capital Expenditures					
Exploration and development expenditures (1)	**$ 77,809**	$ 15,902	$ 153,117	**$ 280,340**	$ 552,291
Acquisitions, net of divestitures	**(33)**	(98)	563	**(182)**	2,180
Total oil and natural gas capital expenditures	**$ 77,776**	$ 15,804	$ 153,680	**$ 280,158**	$ 554,471
Net Debt					
Credit facilities	**$ 651,173**	$ 624,826	$ 506,471	**$ 651,173**	$ 506,471
Long-term notes	**1,147,950**	1,199,160	1,337,200	**1,147,950**	1,337,200
Long-term debt	**1,799,123**	1,823,986	1,843,671	**1,799,123**	1,843,671
Working capital deficiency	**48,478**	82,093	28,120	**48,478**	28,120
Net debt (1)	**$ 1,847,601**	$ 1,906,079	$ 1,871,791	**$ 1,847,601**	$ 1,871,791
Shares Outstanding - basic (thousands)					
Weighted average	**561,173**	561,128	558,228	**560,657**	557,048
End of period	**561,227**	561,163	558,305	**561,227**	558,305
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 42.66**	$ 40.93	$ 56.96	**$ 39.40**	$ 57.03
MEH oil (US$/bbl)	**43.05**	41.63	60.73	**40.15**	62.84
MEH oil differential to WTI (US$/bbl)	**0.39**	0.70	3.77	**0.75**	5.81
Edmonton par ($/bbl)	**50.24**	49.83	68.10	**45.34**	69.22
Edmonton par differential to WTI (US$/bbl)	**(4.11)**	(3.51)	(5.37)	**(5.60)**	(4.86)
WCS heavy oil ($/bbl)	**43.46**	42.40	54.29	**35.95**	58.75
WCS differential to WTI (US$/bbl)	**(9.31)**	(9.09)	(15.83)	**(12.60)**	(12.75)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.66**	$ 1.98	$ 2.50	**$ 2.08**	$ 2.63
AECO ($/mcf)	**2.77**	2.18	2.34	**2.24**	1.62
CAD/USD average exchange rate	**1.3031**	1.3316	1.3201	**1.3413**	1.3269

	Three Months Ended			Twelve Months Ended	
	December 31, 2020	September 30, 2020	December 31, 2019	**December 31, 2020**	December 31, 2019
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**29,568**	34,101	43,906	**37,056**	43,587
Heavy oil (bbl/d)	**21,725**	22,138	27,050	**21,142**	26,741
NGL (bbl/d)	**6,495**	7,417	8,699	**7,340**	10,229
Total liquids (bbl/d)	**57,788**	63,656	79,655	**65,538**	80,557
Natural gas (mcf/d)	**76,116**	84,945	100,235	**85,464**	102,742
Oil equivalent (boe/d @ 6:1) (2)	**70,475**	77,814	96,360	**79,781**	97,680
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (3)	**$ 222,745**	$ 241,865	$ 427,728	**$ 927,096**	$ 1,737,124
Royalties	**(37,807)**	(40,052)	(77,282)	**(163,735)**	(320,241)
Operating expense	**(79,748)**	(73,447)	(99,573)	**(331,345)**	(397,716)
Transportation expense	**(6,692)**	(6,372)	(8,840)	**(28,437)**	(43,942)
Operating netback (1)	**$ 98,498**	$ 121,994	$ 242,033	**$ 403,579**	$ 975,225
General and administrative	**(9,313)**	(7,741)	(9,893)	**(34,268)**	(45,469)
Cash financing and interest	**(25,194)**	(25,418)	(24,389)	**(106,534)**	(107,417)
Realized financial derivatives gain (loss)	**17,105**	(9,743)	22,956	**47,836**	75,620
Other (4)	**1,081**	(584)	1,440	**893**	4,467
Adjusted funds flow (1)	**$ 82,176**	$ 78,508	$ 232,147	**$ 311,506**	$ 902,426
Netback (per boe)					
Total sales, net of blending and other expense (3)	**$ 34.35**	$ 33.79	$ 48.25	**$ 31.75**	$ 48.72
Royalties	**(5.83)**	(5.59)	(8.72)	**(5.61)**	(8.98)
Operating expense	**(12.30)**	(10.26)	(11.23)	**(11.35)**	(11.16)
Transportation expense	**(1.03)**	(0.89)	(1.00)	**(0.97)**	(1.23)
Operating netback (1)	**$ 15.19**	$ 17.05	$ 27.30	**$ 13.82**	$ 27.35
General and administrative	**(1.44)**	(1.08)	(1.12)	**(1.17)**	(1.28)
Cash financing and interest	**(3.89)**	(3.55)	(2.75)	**(3.65)**	(3.01)
Realized financial derivatives gain (loss)	**2.64**	(1.36)	2.59	**1.64**	2.12
Other (4)	**0.17**	(0.09)	0.16	**0.03**	0.13
Adjusted funds flow (1)	**$ 12.67**	$ 10.97	$ 26.18	**$ 10.67**	$ 25.31

Notes:

(1) The terms "adjusted funds flow", "exploration and development expenditures", "net debt" and "operating netback" do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the 2020 MD&A for further information on these amounts.

2020 Results

In one of the most challenging years experienced by our industry, we delivered on our commitment to preserve financial liquidity, capture cost savings, generate free cash flow and keep our operations safe. We also re-set our business in response to the volatile crude oil market and improved our capital efficiencies and overall sustainability.

Production during the fourth quarter averaged 70,475 boe/d (82% oil and NGL), as compared to 77,814 boe/d (82% oil and NGL) in Q3/2020. The reduced volumes reflect a lower level of completion activity in the Viking and Eagle Ford from March through November, and the carry-over of drilled and uncompleted wells into 2021. As we execute our plans for 2021, production has increased to over 78,000 boe/d, consistent with our full-year guidance.

Production in 2020 averaged 79,781 boe/d as compared to 97,680 boe/d in 2019. The lower volumes reflect the approximate 50% reduction in capital spending and the impact of voluntary shut-ins earlier in the year. Exploration and development expenditures totaled $78 million in Q4/2020 and $280 million for full-year 2020. We participated in the completion of 217 (152.4 net) wells with a 100% success rate during the year.

We delivered adjusted funds flow of $82 million ($0.15 per basic share) in Q4/2020 and $312 million ($0.56 per basic share) in 2020. This resulted in free cash flow of $18 million in 2020, which, along with the Canadian dollar strengthening relative to the U.S. dollar, contributed to a $24 million reduction in our net debt this year.

We recorded net income of $221 million ($0.39 per basic share) in Q4/2020 and a net loss of $2.4 billion ($4.35 per basic share) in 2020. In March 2020, due to the sharp decline in forecasted commodity prices, we recorded total impairments of $2.7 billion as the carrying value of our oil and gas properties exceeded the estimated recoverable amounts. At December 31, 2020 with updated development plans and changes in commodity prices, we recorded an impairment reversal of $356 million. Revisions to forecast crude oil prices could result in reversals or additional impairment charges in the future.

The following table compares our 2020 results to our 2020 guidance.

	2020 Guidance		
	Original (1)	**Revised (2)**	**2020 Results**
Exploration and development expenditures	$500 - $575 million	$260 - $290 million	$280 million
Production (boe/d)	93,000 - 97,000	78,000 - 82,000	79,781
Expenses:			
Royalty rate	18.0% - 18.5%	18.5%	17.7%
Operating	$11.25 - $12.00/boe	$11.75 - $12.50/boe	$11.35/boe
Transportation	$1.20 - $1.30/boe	$0.95 - $1.05/boe	$0.97/boe
General and administrative	$45 million ($1.30/boe)	$38 million ($1.30/boe)	$34.3 million ($1.17/boe)
Interest	$112 million ($3.23/boe)	$112 million ($3.84/boe)	$106.5 million ($3.65/boe)
Leasing expenditures	$7 million	$7 million	$6 million
Asset retirement obligations	$19 million	$10 million	$7 million

Note:

(1) As announced on December 4, 2019, prior to Covid-19.
(2) As announced on June 25, 2020. This guidance reference date included a corporate update announcing the resumption of previously shut-in crude oil production.

2021 Guidance

In 2021, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Our priority is to generate stable production, maximize free cash flow and further strengthen our balance sheet.

There is no change to our 2021 annual guidance as announced on December 2, 2020.

	2021 Guidance
Exploration and development expenditures	$225 - $275 million
Production (boe/d)	73,000 – 77,000
Expenses:	
Royalty rate	18.0% - 18.5%
Operating	$11.50 - $12.25/boe
Transportation	$1.00 - $1.10 /boe
General and administrative	$42 million ($1.53/boe)
Interest	$105 million ($3.84/boe)
Leasing expenditures	$4 million
Asset retirement obligations	$6 million

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 25,154 boe/d (77% oil and NGL) during Q4/2020, as compared to 28,650 boe/d in Q3/2020. Production for the full-year 2020 averaged 31,179 boe/d, as compared to 39,055 boe/d in 2019. The lower volumes reflect reduced completion activity as we adjusted our development plan in response to volatile commodity prices. In 2020, we invested $105 million on exploration and development in the Eagle Ford and generated an operating netback of $202 million.

Activity in the Eagle Ford resumed during the fourth quarter with 26 (7.1 net) wells drilled and 9 (2.7 net wells) brought onstream. The remainder of the wells drilled during the fourth quarter are expected to be onstream in Q1/2021. We expect to bring approximately 18 net wells on production in the Eagle Ford in 2021.

Production in the Viking averaged 15,326 boe/d (89% oil and NGL) during Q4/2020, as compared to 18,774 boe/d in Q3/2020. Full-year 2020 production averaged 19,614 boe/d, as compared to 22,546 boe/d in 2019. In 2020, we invested $105 million on exploration and development in the Viking and generated an operating netback of $163 million.

We had previously suspended all drilling in the Viking, and as such, there was limited activity from March through October. We resumed drilling in November with two rigs mobilized to execute a 30-well drilling program. In 2021, we expect to bring approximately 120 net wells onstream, including 43 net wells during the first quarter.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 24,228 boe/d (90% oil and NGL) during the fourth quarter, as compared to 24,791 boe/d in Q3/2020. Production for the full-year 2020 averaged 23,335 boe/d, as compared to 29,378 boe/d in 2019. The impact of voluntary shut-ins for the full-year 2020 was approximately 6,000 boe/d. In addition, we had previously suspended all heavy oil drilling, and as such, there was limited activity during the year. In 2020, we invested $41 million on exploration and development on our heavy oil assets and generated an operating netback of $27 million.

We have scheduled minimal heavy oil development for the first half of 2021. At current commodity prices, we intend to implement a drilling program in the second half of the year, which could see us drill upwards of 30 net wells at Lloydminster and 6 net wells at Peace River.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 2,031 boe/d (84% oil and NGL) during Q4/2020, as compared to 1,474 boe/d in Q3/2020. Production for the full-year 2020 averaged 1,507 boe/d, as compared to 1,688 boe/d in 2019.

We continue to prudently advance our Pembina Duvernay Shale light oil play. Our most recent two wells were completed in October. The 10-16 well was brought on-stream November 2 and generated a 30-day initial production rate of 1,300 boe/d (69% oil). The 11-16 well was brought on-stream November 17 and generated a facility constrained 30-day initial production rate of 900 boe/d (68% oil). Based on early flowback results, these two wells demonstrate repeatability of our 11-30 pad completed in 2019. We have the flexibility in 2021 to drill up to 4 net wells in the second half of the year.

Financial Liquidity

Our credit facilities total approximately $1.03 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of December 31, 2020, we had $367 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $319 million. We are well within our financial covenants and our first long-term note maturity of US$400 million is not until June 2024.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.85 billion at December 31, 2020, down from $1.91 billion at September 30, 2020. Based on the forward strip, we expect to increase our financial liquidity to over $550 million in 2021.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow.

For 2021, we have entered into hedges on approximately 48% of our net crude oil exposure utilizing a combination of fixed price swaps at US$45/bbl and a 3-way option structure that provides price protection at US$44.71/bbl with upside participation to US$52.42/bbl.

We also have WTI-MSW differential hedges on approximately 50% of our expected 2021 Canadian light oil production at US$5.05/bbl and WCS differential hedges on approximately 50% of our expected 2021 heavy oil production at a WTI-WCS differential of approximately US$13.31/bbl.

For 2021, we are contracted to deliver 5,500 bbl/d of our heavy oil volumes to market by rail.

A complete listing of our financial derivative contracts can be found in Note 18 to our 2020 financial statements.

Board Renewal and Governance

Naveen Dargan, a long-standing board member, has announced his intent to retire from the Baytex Board at the 2021 Annual Meeting of Shareholders to be held in April 2021. Baytex thanks Mr. Dargan for his valued contribution during his tenure on the Board. His hard work and dedication for the benefit of all stakeholders is greatly appreciated.

Baytex has an ongoing board renewal process led by the Nominating and Governance Committee of the Board. Since September 2019, Baytex has added three independent Board members from various professional backgrounds. Following Mr. Dargan’s retirement, the Board will be comprised of eight directors with seven of eight being independent, including the Chair of the Board and all committee members. In addition, two of eight directors are women.

ESG – Update on GHG Emissions Reduction

In 2019, Baytex established for the first time a GHG emissions reduction target. Our objective was to reduce our corporate GHG emission intensity (tonnes of CO_2e per boe) by 30% by 2021, relative to our 2018 baseline. We are pleased to announce that we have exceeded this target in scope and timing, achieving a 46% reduction in our GHG emissions intensity through year-end 2020. This represents an annual reduction of 1.6 million tonnes of CO_2e and is equivalent to taking 340,000 cars off the road annually. To achieve our goal, we completed our Peace River gas plant in mid-2018 and significantly advanced our Viking emissions reduction project.

Continual improvement is an important element of our corporate culture and we are setting the bar higher. We have established a new target with an objective to reduce our corporate GHG emission intensity (tonnes of CO2 per boe) by a further 33% from current levels by 2025. This equates to an approximate 65% reduction by 2025, relative to our 2018 baseline. Our emissions reduction strategy includes increased gas conservation and combustion, reusing associated gas as fuel for field activities, reduced emissions from storage tanks, along with monitoring and preventing fugitive emissions.

GHG Emissions Intensity (Scope 1 and Scope 2)

	2018 Baseline	2019	2020	2025 Target
Tonnes CO_2e/boe	0.112	0.095	0.061	0.041

We look forward to publishing our fifth corporate sustainability report later this year as we continue to demonstrate our commitment to transparency and accountability, along with our progress in managing the environmental and social aspects of our business.

Year-end 2020 Reserves

Baytex's year-end 2020 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2021.

Reserves associated with our thermal heavy oil projects at Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2020, which will be filed on or before March 31, 2021.

Our 2020 reserves report reflects the impact of a materially lower commodity price forecast being utilized by our reserves evaluator, which was brought on by Covid-19 and the extremely volatile crude oil market. We highlight the updated commodity price forecast on page 11 which has WTI averaging US$56/bbl over the next ten years, down 20% from one year ago. Consistent with the $2.4 billion impairment we recorded in 2020, we removed 29 million barrels of proved reserves (65% heavy oil and bitumen) and 41 million barrels of proved plus probable reserves (80% heavy oil and bitumen), which are uneconomic under the commodity price forecast.

Reserves Highlights

- Our proved developed producing ("PDP") reserves total 120 mmboe, proved reserves ("1P") total 271 mmboe and our proved plus probable reserves ("2P") total 462 mmboe.
- Reserves on a 1P basis are comprised of 81% oil and NGL (48% light oil, 33% NGL's, 16% heavy oil and 3% bitumen) and 19% natural gas. PDP reserves represent 44% of 1P reserves (45% at year-end 2019) and 1P reserves represent 59% of 2P reserves (59% at year-end 2019).
- Baytex maintains a strong reserves life index of 4.7 years based on PDP reserves, 10.5 years based on 1P reserves and 17.9 years based on 2P reserves.
- Future development costs have been reduced by $464 million on a 1P basis and $709 million on a 2P basis.
- Our net asset value at year-end 2020, discounted at 10%, is estimated to be $2.78 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

The following table sets forth our gross and net reserves volumes at December 31, 2020 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
Gross [1]									
Proved producing	20,404	23,473	19,917	1,144	64,938	31,669	43,384	97,321	120,057
Proved developed non-producing	61	38	1,997	160	2,255	639	15,072	473	5,485
Proved undeveloped	31,601	29,805	13,499	4,433	79,339	40,167	29,438	128,541	145,835
Total proved	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378
Total probable	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332
Proved plus probable	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710
Net [2]									
Proved producing	19,106	17,445	18,404	1,027	55,983	23,635	40,568	72,440	98,452
Proved developed non-producing	59	28	1,895	152	2,135	504	13,080	350	4,877
Proved undeveloped	29,630	22,371	12,385	4,213	68,598	29,865	26,071	95,639	118,748
Total proved	48,795	39,844	32,684	5,393	126,716	54,003	79,270	168,429	222,077
Total probable	23,461	18,777	27,640	40,064	109,941	24,853	80,679	73,061	160,417
Proved plus probable	72,256	58,621	60,324	45,456	236,657	78,856	160,398	241,490	382,495

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category. Please note that the data in the table may not add due to rounding.

Proved Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (3) (mbbls)	Conventional Natural Gas (4) (mmcf)	Shale Gas (mmcf)	Total (5) (mboe)
December 31, 2019	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674
Extensions	2,840	1,618	160	3,027	7,645	1,541	12,937	4,038	12,015
Technical Revisions (2)	(1,275)	1,780	2,462	(1,224)	1,743	(758)	9,360	7,225	3,749
Acquisitions	16	—	—	—	16	1	19	—	20
Dispositions	(15)	—	(5)	—	(20)	—	(38)	—	(26)
Economic Factors	(3,421)	(592)	(11,698)	(6,945)	(22,655)	(1,748)	(23,824)	(2,877)	(28,854)
Production	(6,698)	(5,052)	(6,818)	(920)	(19,488)	(4,499)	(15,066)	(16,213)	(29,200)
December 31, 2020	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378

Probable Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (3) (mbbls)	Conventional Natural Gas (4) (mmcf)	Shale Gas (mmcf)	Total (5) (mboe)
December 31, 2019	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818
Extensions	(1,937)	1,291	244	696	294	908	(11,371)	5,283	187
Technical Revisions (2)	(3,643)	(648)	(1,634)	(366)	(6,291)	(3,954)	(10,854)	(6,929)	(13,208)
Acquisitions	3	—	—	—	3	—	3	—	4
Dispositions	(92)	—	(4)	—	(96)	(4)	(348)	—	(158)
Economic Factors	139	(141)	(5,867)	(7,980)	(13,849)	157	9,531	(1,240)	(12,311)
Production	—	—	—	—	—	—	—	—	—
December 31, 2020	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332

Proved Plus Probable Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (3) (mbbls)	Conventional Natural Gas (4) (mmcf)	Shale Gas (mmcf)	Total (5) (mboe)
December 31, 2019	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492
Extensions	903	2,909	404	3,723	7,939	2,449	1,565	9,320	12,202
Technical Revisions (2)	(4,917)	1,132	827	(1,590)	(4,548)	(4,712)	(1,494)	296	(9,460)
Acquisitions	19	—	—	—	19	1	22	—	24
Dispositions	(107)	—	(8)	—	(116)	(4)	(386)	—	(184)
Economic Factors	(3,282)	(733)	(17,565)	(14,925)	(36,505)	(1,592)	(14,293)	(4,118)	(41,165)
Production	(6,698)	(5,052)	(6,818)	(920)	(19,488)	(4,499)	(15,066)	(16,213)	(29,200)
December 31, 2020	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Positive and negative revisions in heavy oil, bitumen, light and medium oil and tight oil are due to variations in performance versus previous forecasts in our Viking, Eagle Ford, Peace River and Lloydminster assets. Technical revisions for conventional natural gas are a combination of performance revisions in our Deep Basin assets and performance revisions for solution gas (classified as conventional natural gas) from our light and heavy oil properties. Positive revisions for shale gas are attributed to improved performance in the Duvernay and Eagle Ford assets.

(3) Natural gas liquids include condensate.

(4) Conventional natural gas includes associated, non-associated and solution gas.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2021	276	283
2022	439	491
2023	477	560
2024	432	538
2025	420	580
Remainder	50	1,153
Total FDC undiscounted	2,094	3,606

F&D and FD&A Costs – including future development costs

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our capital program is summarized in the following table.

millions except for per boe amounts	2020	2019	2018	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Net change in Future Development Costs	($705.9)	$96.7	$132.3	($476.8)
Gross Reserves additions (mmboe)	(38.4)	39.8	31.2	32.6
F&D Costs ($/boe)	$11.08	$16.30	$20.11	$26.09
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Net change in Future Development Costs	($709.3)	$79.9	$1,064.5	$435.1
Gross Reserves additions (mmboe)	(38.6)	38.6	123.9	123.9
FD&A Costs ($/boe)	$11.12	$16.42	$25.55	$27.19
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Net change in Future Development Costs	($464.4)	($90.4)	$117.4	($437.4)
Gross Reserves additions (mmboe)	(13.1)	35.8	17.5	40.2
F&D Costs ($/boe)	$14.06	$12.92	$35.05	$22.18
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Net change in Future Development Costs	($464.4)	($107.2)	$987.4	$415.8
Gross Reserves additions (mmboe)	(13.1)	34.7	88.4	110.0
FD&A Costs ($/boe)	$14.07	$12.88	$34.91	$30.44
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Gross Reserves additions (mmboe)	7.7	42.5	31.3	81.3
F&D Costs ($/boe)	$36.63	$13.04	$15.82	$16.33
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Gross Reserves additions (mmboe)	7.6	42.5	63.7	113.9
FD&A Costs ($/boe)	$36.64	$13.04	$32.95	$25.76

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2020 by annualized Q4/2020 production.

	Q4/2020 Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Crude Oil and NGL (bbl/d)	57,788	10.4	18.0
Natural Gas (mcf/d)	76,116	11.3	17.9
Oil Equivalent (boe/d)	70,475	10.5	17.9

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2020. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2020.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2020 act.	39.20	45.00	35.35	2.05	2.25	0.2	0.745
2021	47.17	55.76	44.63	2.83	2.78	0.0	0.768
2022	50.17	59.89	48.18	2.87	2.70	1.3	0.765
2023	53.17	63.48	52.10	2.90	2.61	2.0	0.763
2024	54.97	65.76	54.10	2.96	2.65	2.0	0.763
2025	56.07	67.13	55.19	3.02	2.70	2.0	0.763
2026	57.19	68.53	56.29	3.08	2.76	2.0	0.763
2027	58.34	69.95	57.42	3.14	2.81	2.0	0.763
2028	59.50	71.40	58.57	3.20	2.87	2.0	0.763
2029	60.69	72.88	59.74	3.26	2.92	2.0	0.763
2030	61.91	74.34	60.93	3.33	2.98	2.0	0.763
Thereafter			Escalation rate of 2.0%			2.0	0.763

Net Present Value of Reserves (1) (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2020 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	1,089	1,203	1,118	1,018
Proved developed non-producing	69	59	51	46
Proved undeveloped	2,221	1,443	972	671
Total proved	3,379	2,704	2,141	1,735
Probable	3,374	1,837	1,138	771
Total Proved Plus Probable (before tax)	6,753	4,542	3,279	2,505

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.

Net Asset Value (Forecast Prices and Costs)

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel at year-end, plus the estimated value of our undeveloped land holdings, less net debt. This calculation can vary significantly depending on the oil and natural gas price assumptions. In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development.

The following table sets forth our net asset value as at December 31, 2020.

($ millions, except per share amounts, discounted at)	**5%**	**10%**	**15%**
Net present value of proved plus probable reserves (1)	4,542	3,279	2,505
Undeveloped land holdings (2)	130	130	130
Net Debt	(1,848)	(1,848)	(1,848)
Net Asset Value	2,824	1,561	787
Net Asset Value per Share (3)	5.03	2.78	1.40

Notes:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.
(2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(3) Based on 561.2 million common shares outstanding as at December 31, 2020.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2020 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, February 25, 2021, starting at 9:00am MST (11:00am EST). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytex20210225.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", ""estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we are on track to deliver $250 million ($0.45 per basic share) of free cash flow in 2021, are building operational momentum and executing our plan to maximize free cash flow and accelerate our debt reduction strategy; in 2021 that: we will benefit from a disciplined approach to capital allocation and a continued drive to improve our cost structure and capital efficiencies, our high graded capital program is focused on high netback light oil assets in the Viking and Eagle Ford and that, at current commodity prices, we intend to implement a heavy oil program in the second half of the year; our guidance for 2021 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; that 48% of our net crude oil exposure for 2021 is hedged; In 2021, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively and that our priority is to generate stable production, maximize free cash flow and further strengthen our balance sheet; for 2021 in the Eagle Ford: we expect to bring wells drilled in Q4/2020 on stream in Q1/2021 and bring 18 net wells on production; in the Viking: that we expect to bring 43 net wells on stream in Q1/2020 and 120 net wells on stream in 2021; we have minimal heavy oil development scheduled in H1/2021 and, at current commodity prices, we intend to implement a drilling program in H2/2021 with upwards of 30 net wells drilled at Lloydminster and 6 net wells drilled at Peace River; in Pembina Duvernay we have flexibility to drill up to 4 net wells in H2/2021; based on the forward strip, we expect to increase our financial liquidity to approximately $500 million in 2021; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility and the percentage of our expected production in 2021 of Canadian light oil and heavy oil for which we have hedged the differential to WTI; our 2025 GHG emissions intensity reduction target and our strategy to reach the target; that we plan to publish our fifth corporate sustainability report this year; future development costs, F&D and FD&A; our reserves life index; forecast prices for oil and natural gas; forecast inflation and exchange *rates; the net present value before income taxes of the future net revenue attributable to our reserves; the value of our undeveloped land holdings and our estimated net asset value. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.*

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); the availability and cost of capital or borrowing; risks associated with our ability to exploit our properties and add reserves; availability and cost of gathering, processing and pipeline systems; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; costs to develop and operate our properties; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; results of litigation; risks associated with large projects; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2020, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2021 and in our other public filings

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial and Capital Management Measures

In this press release, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP ("non-GAAP measures") and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2020.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. Our *determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.*

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2020, which will be filed on or before March 31, 2021. Listed below are cautionary statements that are specifically required by NI 51-101:

- *The term barrels of oil equivalent (''boe'') may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2020. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2020					Twelve Months Ended December 31, 2020				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	10,918	9	14	13,295	13,157	9,853	7	12	11,630	11,810
Lloydminster	10,807	8	—	1,541	11,072	11,289	12	—	1,346	11,525
Canada - Light										
Viking	—	13,524	127	10,044	15,326	—	17,658	113	11,058	19,614
Duvernay	—	1,138	572	1,929	2,031	—	803	432	1,634	1,507
Remaining Properties	—	533	651	15,309	3,736	—	623	668	17,131	4,147
United States										
Eagle Ford	—	14,356	5,131	33,999	25,154	—	17,953	6,116	42,665	31,179
Total	21,725	29,568	6,495	76,116	70,475	21,142	37,056	7,340	85,463	79,781

This press release discloses per boe 30-day initial production volumes for two wells drilled in the Pembina Duvernay. The disaggregated 30-day initial production volumes for the 10-16 well were 885 bbl/d Light and Medium Oil, 279 bbl/d NGL and 750 Mcf/d Natural Gas and for the 11-16 well were 601 bbl/d Light and Medium Oil, 195 bbl/d NGL and 522 Mcf/d Natural Gas.

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "net asset value", and "reserves life index." These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Finding, development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2020, plus the estimated value of our undeveloped land holdings, less net debt.

Reserve life index means the reserves for the particular reserve category divided by annualized 2020 fourth quarter production.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 81% of Baytex’s production is weighted toward crude oil and natural gas liquids. Baytex’s common shares trade on the Toronto Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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