BAYTEX ANNOUNCES FIRST QUARTER 2021 FINANCIAL AND OPERATING RESULTS AND PROVIDES FIVE YEAR OUTLOOK WITH CUMULATIVE FREE CASH FLOW OF $1 BILLION

CALGARY, ALBERTA (April 29, 2021) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three months ended March 31, 2021 (all amounts are in Canadian dollars unless otherwise noted).

"We delivered strong first quarter production and free cash flow as we accelerate our deleveraging strategy. At current commodity prices, we expect to generate over $250 million of free cash flow in 2021 and we have an exciting, new, oil exploration discovery in the Clearwater oil play in Peace River with follow-up drilling already scheduled for H2/2021. I am also pleased to announce our five-year outlook which demonstrates our operational and financial strength in a US$55 WTI pricing environment as we target over $1 billion of cumulative free cash flow through 2025," commented Ed LaFehr, President and Chief Executive Officer.

Q1 2021 Highlights

- Generated production of 78,780 boe/d (81% oil and NGL), a 12% increase over Q4/2020.
- Delivered adjusted funds flow of $157 million ($0.28 per basic share), a 91% increase compared to $82 million ($0.15 per basic share) in Q4/2020.
- Generated free cash flow of $70 million ($0.13 per basic share).
- Realized an operating netback of $29.80/boe, up from $15.19/boe in Q4/2020.
- Reduced net debt by $89 million through a combination of free cash flow and the Canadian dollar strengthening relative to the U.S. dollar.

2021 Outlook

We are benefiting from a disciplined approach to capital allocation and improvements to our cost structure and capital efficiencies along with the recovery in commodity prices. Drilling activity resumed late last year and we are building significant operational momentum with first quarter production up 12% from Q4/2020, largely driven by our light oil business. We are on track to deliver over $250 million ($0.45 per basic share) of free cash flow, which will accelerate our debt reduction efforts.

As a result of this operational momentum and the strength in commodity prices, we are increasing both our production and capital spending guidance. This will position our business for continued strong operating performance and free cash flow generation going forward. We are now forecasting 2021 exploration and development expenditures of $285 to $315 million, up from $225 to $275 million, which was set in a US$40 to US$45 pricing environment. The increased expenditures will largely occur in the fourth quarter and will be allocated across our portfolio of light and heavy oil assets, including our emerging Clearwater play at Peace River. Our revised production guidance range is 77,000 to 79,000 boe/d, up from 73,000 to 77,000 boe/d.

Five-Year Outlook

We are providing a five-year outlook (2021 to 2025) to highlight our financial and operational sustainability and meaningful free cash flow generation. Through this plan period, we will maintain a disciplined and returns based capital allocation philosophy.

Assuming a constant US$55/bbl WTI price, we will target capital expenditures at less than 70% of our adjusted funds flow, while optimizing our production in the 80,000 to 85,000 boe/d range. We project annual capital spending of approximately $400 million from 2022 to 2025 and expect to generate over $1 billion of cumulative free cash flow. Our leverage ratios are expected to improve materially as we target a net debt to EBITDA ratio of under 1.5x. Throughout the plan period we will continue to monitor our leverage position and assess market conditions to determine the best methods or combination thereof to enhance shareholder returns. These could include share buy-backs, a dividend or reinvestment for organic growth.

	Three Months Ended		
	March 31, 2021	December 31, 2020	March 31, 2020
FINANCIAL			
(thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 384,702**	$ 233,636	$ 336,614
Adjusted funds flow (1)	**156,582**	82,176	132,935
Per share - basic	**0.28**	0.15	0.24
Per share - diluted	**0.28**	0.15	0.24
Net income (loss)	**(35,352)**	221,160	(2,498,217)
Per share - basic	**(0.06)**	0.39	(4.46)
Per share - diluted	**(0.06)**	0.39	(4.46)
Capital Expenditures			
Exploration and development expenditures (1)	**$ 83,588**	$ 77,809	$ 176,777
Acquisitions, net of divestitures	**(203)**	(33)	(40)
Total oil and natural gas capital expenditures	**$ 83,385**	$ 77,776	$ 176,737
Net Debt			
Credit facilities (2)	**$ 606,637**	$ 651,173	$ 678,740
Long-term notes (2)	**1,131,480**	1,147,950	1,270,800
Long-term debt	**1,738,117**	1,799,123	1,949,540
Working capital deficiency	**20,777**	48,478	102,077
Net debt (1)	**$ 1,758,894**	$ 1,847,601	$ 2,051,617
Shares Outstanding - basic (thousands)			
Weighted average	**562,085**	561,173	559,804
End of period	**564,111**	561,227	560,483
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 57.84**	$ 42.66	$ 46.17
MEH oil (US$/bbl)	**59.36**	43.05	49.54
MEH oil differential to WTI (US$/bbl)	**1.52**	0.39	3.37
Edmonton par ($/bbl)	**66.58**	50.24	51.43
Edmonton par differential to WTI (US$/bbl)	**(5.27)**	(4.11)	(7.92)
WCS heavy oil ($/bbl)	**57.46**	43.46	34.48
WCS differential to WTI (US$/bbl)	**(12.46)**	(9.31)	(20.53)
Natural gas			
NYMEX (US$/mmbtu)	**$ 2.69**	$ 2.66	$ 1.95
AECO ($/mcf)	**2.93**	2.77	2.14
CAD/USD average exchange rate	**1.2663**	1.3031	1.3445

	Three Months Ended		
	March 31, 2021	December 31, 2020	March 31, 2020
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**35,430**	29,568	45,717
Heavy oil (bbl/d)	**21,989**	21,725	28,854
NGL (bbl/d)	**6,238**	6,495	7,822
Total liquids (bbl/d)	**63,657**	57,788	82,393
Natural gas (mcf/d)	**90,739**	76,116	96,356
Oil equivalent (boe/d @ 6:1) (3)	**78,780**	70,475	98,452
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (4)	**$ 367,582**	$ 222,745	$ 315,257
Royalties	**(66,950)**	(37,807)	(56,720)
Operating expense	**(80,548)**	(79,748)	(104,470)
Transportation expense	**(8,788)**	(6,692)	(10,342)
Operating netback (1)	**$ 211,296**	**$ 98,498**	**$ 143,725**
General and administrative	**(8,733)**	(9,313)	(9,775)
Cash financing and interest	**(24,403)**	(25,194)	(28,535)
Realized financial derivatives (loss) gain	**(20,768)**	17,105	26,850
Other (5)	**(810)**	1,080	670
Adjusted funds flow (1)	**$ 156,582**	**$ 82,176**	**$ 132,935**
Netback (per boe)			
Total sales, net of blending and other expense (4)	**$ 51.84**	$ 34.35	$ 35.19
Royalties	**(9.44)**	(5.83)	(6.33)
Operating expense	**(11.36)**	(12.30)	(11.66)
Transportation expense	**(1.24)**	(1.03)	(1.15)
Operating netback (1)	**$ 29.80**	**$ 15.19**	**$ 16.05**
General and administrative	**(1.23)**	(1.44)	(1.09)
Cash financing and interest	**(3.44)**	(3.89)	(3.19)
Realized financial derivatives (loss) gain	**(2.93)**	2.64	3.00
Other (5)	**(0.12)**	0.17	0.07
Adjusted funds flow (1)	**$ 22.08**	**$ 12.67**	**$ 14.84**

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) Principal amount of instruments. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of capital or repayment obligations.

(3) 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.

(4) 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.

(5) 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 Q1/2021 MD&A for further information on these amounts.

Q1/2021 Results

During Q1/2021, we executed on our plan to maximize free cash flow and reduce debt. During the quarter, we delivered adjusted funds flow of $157 million ($0.28 per basic share). This resulted in free cash flow of $70 million, which, along with the Canadian dollar strengthening relative to the U.S. dollar, contributed to an $89 million reduction in our net debt.

Production during the first quarter averaged 78,780 boe/d (81% oil and NGL), up 12% as compared to 70,475 boe/d (82% oil and NGL) in Q4/2020. The increased production largely reflects the resumption of drilling activity in the Viking and Eagle Ford which began in the fourth quarter. Exploration and development expenditures totaled $84 million in Q1/2021 that included the drilling of 68 (46.5 net) wells with a 100% success rate.

2021 Guidance

In 2021, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Based on the forward strip(1), we expect to generate over $250 million of free cash flow in 2021.

As a result of our strong operational momentum and the strength in commodity prices, we are increasing both our production and capital spending guidance. This will position our business for continued strong operating performance and free cash flow generation going forward. We are now forecasting 2021 exploration and development expenditures of $285 to $315 million, up from $225 to $275 million, which was set in a US$40 to US$45 pricing environment. The increased spend will largely occur in the fourth quarter and will be allocated across our portfolio of light and heavy oil assets. Our revised production guidance range is 77,000 to 79,000 boe/d, up from 73,000 to 77,000 boe/d.

We have also fine-tuned several of our cost assumptions to reflect higher production volumes and increased activity. In addition, our interest expense guidance is 7% lower due to reduced net debt and the Canadian dollar strengthening relative to the U.S. dollar.

The following table highlights our updated 2021 annual guidance.

	2021 Guidance (2)	2021 Revised Guidance
Exploration and development expenditures	$225 - $275 million	$285 - $315 million
Production (boe/d)	73,000 - 77,000	77,000 - 79,000
Expenses:		
Royalty rate	18.0% - 18.5%	no change
Operating	$11.50 - $12.25/boe	$11.25 - $12.00/boe
Transportation	$1.00 - $1.10/boe	$1.15 - $1.25/boe
General and administrative	$42 million ($1.53/boe)	$42 million ($1.48/boe)
Interest	$105 million ($3.84/boe)	$98 million ($3.46/boe)
Leasing expenditures	$4 million	no change
Asset retirement obligations	$6 million	no change

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 26,741 boe/d (77% oil and NGL) during Q1/2021, as compared to 25,154 boe/d in Q4/2020. During the first quarter, we commenced production from 24 (7.0 net) wells, up from 9 (2.7 net) wells in Q4/2020. In Q1/2021, we invested $41 million on exploration and development in the Eagle Ford and generated an operating netback of $84 million. We expect to bring approximately 20 net wells on production in the Eagle Ford in 2021, up from 18 net wells previously.

Notes:

(1) 2021 full-year pricing assumptions: WTI - US$60/bbl; WCS differential - US$12/bbl; MSW differential – US$4.5/bbl, NYMEX Gas - US$2.80/mcf; AECO Gas - $2.80/mcf and Exchange Rate (CAD/USD) - 1.25.
(2) As announced on December 2, 2020.

Production in the Viking averaged 19,403 boe/d (91% oil and NGL) during Q1/2021, as compared to 15,326 boe/d in Q4/2020. During the first quarter, we commenced production from 44 (43.2 net) wells. In Q1/2021, we invested $35 million on exploration and development in the Viking and generated an operating netback of $72 million. We expect to bring approximately 120 net wells on production in the Viking in 2021.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 24,395 boe/d (90% oil and NGL) during the Q1/2021, as compared to 24,228 boe/d in Q4/2020. We scheduled minimal heavy oil development for the first half of 2021. Our heavy oil program is expected to kick off in July with 35 net wells planned for the year, including up to six net wells in our Spirit River (Clearwater equivalent) play.

Peace River Clearwater

Across all of our core assets, inventory enhancement continues to be a priority. We are also committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. One year ago, we executed a strategic agreement with the Peavine Metis settlement in the Peace River area that covers 60 sections of land directly to the south of our existing Seal operations. At the time, we identified significant potential for this early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent.

Our initial exploration well was drilled during the first quarter and has shown promising early results with a 30-day initial production rate of 175 bbl/d from two laterals. With this early success, we are planning up to six additional Clearwater multi-lateral wells for H2/2021. Across our acreage position in northwest Alberta, we estimate that over 100 sections are prospective for Clearwater development.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 2,138 boe/d (84% oil and NGL) during Q1/2021, as compared to 2,031 boe/d in Q4/2020. We now have nine producing wells in the Pembina area and have significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold 232 sections (100% working interest) of Duvernay land. We plan to drill a further two 100% working interest wells in the second half of the year.

Financial Liquidity

Our credit facilities total approximately $1.0 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 March 31, 2021, we had $401 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $381 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 $1.76 billion at March 31, 2021, down from $1.85 billion at December 31, 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 47% 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 55% of our expected 2021 heavy oil production at a WTI-WCS differential of approximately US$13.31/bbl.

For 2022, we have entered into hedges on approximately 33% of our net crude oil exposure utilizing a combination of swaptions at US$53.50/bbl and a 3-way option structure that provides price protection at US$54.91/bbl with upside participation to US$64.68/bbl. We also have WCS differential hedges on approximately 35% of our expected 2022 heavy oil production at a WTI-WCS differential of approximately US$12.47/bbl.

A complete listing of our financial derivative contracts can be found in Note 16 to our Q1/2021 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2021 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. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, April 30, 2021, starting at 9:00am MDT (11:00am EDT). 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/baytex20210430.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; our 2021 plan to maximize free cash flow and accelerate our deleveraging strategy; expected 2021 free cash flow and liquidity; that our 5 year-outlook demonstrates financial and operational sustainability at US$55 WTI and will generate >$1 billion of cumulative free cash flow; our Clearwater drilling plans for H2/2021; our revised capital spending and production guidance for 2021, and the timing and location of our incremental capital spending; for our 2021 outlook: that we will maintain a disciplined and returns based capital allocation philosophy, assumes US $55 WTI constant pricing, targets capital spending at less than 70% of adjusted fund flow; the associated annual capital spending, materially improves our leverage metrics, targets net debt to EBITDA of under 1.5x, positions for enhanced shareholder returns which could be share buy-backs, a dividend or reinvestment for organic growth; 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; updated 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; in 2021 that we expect to: bring on production 20 net wells in the Eagle Ford and 120 in the Viking, kick off our heavy oil program in July and drill 35 net wells, including 6 additional Clearwater wells, and drill 2 net wells in the Duvernay; that we have 100 sections of highly prospective Clearwater lands and that we have de-risked our approximately 38-kilometer acreage fairway in the Pembina Duvernay; that we expect to maintain our financial liquidity and our expected liquidity at year-end 2021; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility, the percentage of our expected production in 2021 and 2022 we have hedged and the percentage of our expected exposure to the light oil differential and heavy oil differential to WTI we have hedged. 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, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission 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 news 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 three months ended March 31, 2021.

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

Where applicable, 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.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Throughout this news 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 months ended March 31, 2021. 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 March 31, 2021				
	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	12,170	8	24	12,683	14,316
Lloydminster	9,819	5	—	1,529	10,079
Canada - Light					
Viking	—	17,466	133	10,823	19,403
Duvernay	—	1,148	657	1,997	2,138
Remaining Properties	—	601	1,156	26,077	6,103
United States					
Eagle Ford	—	16,202	4,268	37,630	26,741
Total	21,989	35,430	6,238	90,739	78,780

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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