UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): February 12, 2020

LAREDO PETROLEUM, INC.
(Exact name of registrant as specified in charter)

Delaware	**001-35380**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street	**Suite 900**	
Tulsa	**Oklahoma**	**74119**
(Address of principal executive offices)		(Zip code)

Registrant's telephone number, including area code: **(918) 513-4570**

Not Applicable
(Former name or former address, if changed since last report)

Securities registered pursuant to Section 12(b) of the Exchange Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common stock, $0.01 par value	**LPI**	**New York Stock Exchange**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

☐ Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.
☐

Item 2.02. Results of Operations and Financial Condition.

On February 12, 2020, the Company announced its financial and operating results for the quarter and year ended December 31, 2019. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on February 13, 2020 at 7:30 am Central Time to discuss these results. To access the call, please dial 1.877.930.8286 or 1.253.336.8309 for international callers, and use conference code 2388743. A replay of the call will be available through Thursday, February 20, 2020, by dialing 1.855.859.2056, and using conference code 2388743. The webcast may be accessed at the Company's website, www.laredopetro.com, under the tab "Investor Relations."

In accordance with General Instruction B.2 of the Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibits attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended (the "Securities Act"), or the Exchange Act.

Item 7.01. Regulation FD Disclosure.

On February 12, 2020, the Company furnished the press release described above in Item 2.02 of this Current Report on Form 8-K. The press release is attached hereto as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

On February 12, 2020, The Company also posted to its website a corporate presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached hereto as Exhibit 99.2 and incorporated into this Item 7.01 by reference.

All statements in the press release, teleconference and the Presentation, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. See the Company's Annual Report on Form 10-K for the year ended December 31, 2018 and the Company's Annual Report on Form 10-K for the year ended December 31, 2019, to be filed with the SEC, and the Company's other filings with the SEC for a discussion of other risks and uncertainties. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of the Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibits attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Exchange Act, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference in any filing under the Securities Act or the Exchange Act.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit Number	Description
99.1	Press Release dated February 12, 2020.
99.2	Corporate Presentation dated February 12, 2020.
104	Cover Page Interactive Data File (formatted as Inline XBRL).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Date: February 12, 2020	By:	/s/ Michael T. Beyer
		Michael T. Beyer
		Senior Vice President and Chief Financial Officer

EXHIBIT 99.1

15 West 6th Street, Suite 900 · Tulsa, Oklahoma 74119 · (918) 513-4570 · Fax: (918) 513-4571
www.laredopetro.com

Laredo Petroleum Announces Fourth-Quarter and Full-Year 2019 Financial and Operating Results

TULSA, OK - February 12, 2020 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its fourth-quarter and full-year 2019 results. For the fourth quarter of 2019, the Company reported a net loss attributable to common stockholders of $241.7 million, or $1.04 per diluted share, which includes a non-cash full cost ceiling impairment charge of $222.7 million. Adjusted Net Income, a non-GAAP financial measure, for the fourth quarter of 2019 was $39.7 million, or $0.17 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the fourth quarter of 2019 was $137.9 million.

For full-year 2019, the Company reported a net loss attributable to common stockholders of $342.5 million, or $1.48 per diluted share, which includes a non-cash full cost ceiling impairment charge of $620.6 million. Adjusted Net Income for full-year 2019 was $172.0 million, or $0.74 per adjusted diluted share and Adjusted EBITDA was $560.2 million.

Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures, including a calculation of Adjusted EBITDA, Adjusted Net Income and Free Cash Flow.

2019 Full-Year Highlights

- Generated $475.1 million of net cash provided by operating activities and $59.7 million of Free Cash Flow in 2019 as the Company reduced capital expenditures by 25% from full-year 2018
- Executed two accretive acquisitions of high-margin, oily inventory at valuations significantly below historic averages while maintaining a competitive leverage ratio
- Produced 28,429 barrels of oil per day ("BOPD") and 80,883 barrels of oil equivalent ("BOE") per day, increases of 2% and 19%, respectively, from full-year 2018
- Grew total proved reserves by 55 million BOE and proved oil reserves by 17 million barrels, increases of 23% and 27%, respectively, versus year-end 2018
- Drove well costs down to $6.6 million for a 10,000-foot lateral with the Company's standard completion design, a decrease from $7.7 million at year-end 2018
- Reduced controllable cash costs of combined unit lease operating expenses ("LOE") and unit cash general and administrative expenses ("G&A") to $4.65 per BOE, a 23% decrease from full-year 2018 results of $6.07 per BOE

- Received net cash of $48.7 million on settlements of derivatives, as the Company's hedges mitigated the impact of commodity price declines

"During 2019, we successfully completed our transition to a returns-focused, free-cash-flow-oriented strategy," stated Jason Pigott, President and Chief Executive Officer. "We substantially improved well productivity, aligned staffing with our moderated development plan and continued to drive down both our well costs and operational expenses. Our strong performance in all facets of the business drove improved capital efficiency and Free Cash Flow generation of approximately $60 million for full-year 2019."

"We leveraged our strengths to complete two accretive acquisitions in oilier areas of the Midland Basin," continued Mr. Pigott. "By deploying our proven operational expertise on acreage with higher oil content, we expect to further improve margins and capital efficiency and drive our oil mix above 40% by 2022. Our development program over the next three years is designed to maintain production levels, generate positive Projected Free Cash Flow at $50 per barrel and deliver more than $100 million in Projected Free Cash Flow at $55 per barrel."

"Financially, we are well positioned to continue delivering on our returns-focused strategy. In January of 2020, we opportunistically refinanced our senior unsecured notes, extending our maturities to 2025 and 2028. For 2020, we have hedged a substantial portion of our expected production at prices well above current levels. Laredo is committed to maintaining its financial strength, improving inventory quality and utilizing Free Cash Flow to reduce debt."

E&P Update

During the fourth quarter of 2019, Laredo completed 15 gross (13.1 net) horizontal wells, all on the Company's wider spacing development plan, with an average completed lateral length of 9,900 feet. Drilling and completion cost incurred of $97 million was in-line with expectations, even with one additional completion, as the Company achieved performance records for both feet drilled and completed feet per day.

In the fourth quarter of 2019, the Company exceeded both oil and total production expectations for the fourth consecutive quarter. Oil production of 27,296 BOPD beat guidance by 5% and total production of 83,968 BOE per day beat guidance by 10%. The primary driver of oil production exceeding expectations during the quarter was the outperformance of the nine-well Sugg/Von Gonten package. This package is currently exceeding the Company's Upper/Middle Wolfcamp oil type curve by 39%.

In the first quarter of 2020, Laredo expects to complete 28 gross (27.7 net) widely-spaced horizontal wells with an average completed lateral length of 8,500 feet. All anticipated first-quarter 2020 completions are on the Company's established acreage in Reagan and Glasscock counties. The Company is currently operating two completion crews and expects to reduce activity to one completion crew by the end of March 2020 as completion activities transition to the newly acquired acreage in Howard and Glasscock counties in the second quarter of 2020.

Howard County Update

Laredo's transition to its recently acquired Howard County position is moving forward as planned. Two of the Company's four drilling rigs have been deployed to Howard County and a third is expected early in March 2020. The first well of Laredo's first 15-well package in Howard County has been successfully drilled and completion operations are expected to commence on the full package during the second quarter of 2020. Additionally, the Company is in negotiations with multiple third-party providers of oil, natural gas and water infrastructure services and does not expect costs for these services to be significantly different from those on the Company's established acreage base.

In early-February 2020, Laredo executed a bolt-on transaction to its tier-one Howard County position, adding 1,100 net acres for $22.5 million. The acquisition increases the Company's working interest on its operated acreage from 83% to 96%, bringing Laredo's Howard County leasehold to 8,380 net acres (99% operated). The transaction increases the Company's operated inventory in Howard County to 130 gross (124 net) primary locations in the Lower Spraberry, Upper Wolfcamp and Middle Wolfcamp formations.

2019 Capital Program

During the fourth quarter of 2019, excluding non-budgeted acquisitions, total costs incurred were $107 million, comprised of $97 million in drilling and completions activities, $2 million in land and data related costs, $2 million in infrastructure, including Laredo Midstream Services investments, and $6 million in other capitalized costs.

Total costs incurred of $482 million for full-year 2019, excluding non-budgeted acquisitions, was below the Company's $490 million capital budget. For full-year 2019, Laredo delivered approximately $60 million in Free Cash Flow, excluding non-budgeted acquisitions.

Commodity Derivatives

For full-year 2020, the Company has hedged 9.6 million barrels of oil, including 7.2 million barrels at $59.50 WTI and 2.4 million barrels at $63.07 Brent, and 23.8 million MMBtu of natural gas at $2.72 per MMBtu Henry Hub. Combined, Laredo's commodity derivatives are expected to generate $152 million of positive cash flow at $50 per barrel WTI and $2.25 per MMBtu Henry Hub.

Liquidity

At December 31, 2019, the Company had outstanding borrowings of $375 million on its $1.0 billion senior secured credit facility, resulting in available capacity, after the reduction for outstanding letters of credit, of $610 million. Including cash and cash equivalents of $41 million, total liquidity was $651 million.

In January 2020, Laredo issued $1.0 billion of new senior unsecured notes with the net proceeds to be used to redeem its existing $800 million of outstanding senior unsecured notes and to partially repay its senior secured credit facility. To date, the Company has redeemed $749.4 million of the existing notes and has issued call notices for the remaining $50.6 million. In conjunction with the closing of the notes issuance, the Company's borrowing base under its senior secured credit facility was reduced to approximately $950 million.

At February 11, 2020, the Company had outstanding borrowings of $275 million on its senior secured credit facility, resulting in available capacity, after reductions for outstanding letters of credit, of $660 million. Including cash and cash equivalents of $67 million, net of expected cash to be used to redeem the remaining March 2023 Notes, total liquidity was $727 million.

First-Quarter 2020 Guidance

	1Q-2020E
Total production (MBOE per day)	81.2 - 81.7
Oil production (MBOPD)	26.8 - 27.3
Average sales price realizations (excluding derivatives):	
Oil (% of WTI)	100%
NGL (% of WTI)	14%
Natural gas (% of Henry Hub)	13%
Other ($ MM):	
Net income / (expense) of purchased crude oil	($4.0)
Net midstream income / (expense)	$1.5
Selected average costs & expenses:	
Lease operating expenses ($/BOE)	$3.00
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)	6.50%
Transportation and marketing expenses ($/BOE)	$2.15
General and administrative:	
Cash ($/BOE)	$1.60
Non-cash stock-based compensation, net ($/BOE)	$0.55
Depletion, depreciation and amortization ($/BOE)	$9.00

Conference Call Details

On Thursday, February 13, 2020, at 7:30 a.m. CT, Laredo will host a conference call to discuss its fourth-quarter and full-year 2019 financial and operating results and management's outlook, the content of which is not part of this earnings release. A slide presentation providing summary financial and statistical information that will be discussed on the call will be posted to the Company's website and available for review. The Company invites interested parties to listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." Portfolio managers and analysts who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 2388743, 10 minutes prior to the scheduled conference time. A telephonic replay will be available two hours after the call on February 13, 2020 through Thursday, February 20, 2020. Participants may access this replay by dialing 855.859.2056, using conference code 2388743.

About Laredo

Laredo Petroleum, Inc. is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas.

Additional information about Laredo may be found on its website at www.laredopetro.com.

Forward-Looking Statements

This press release and any oral statements made regarding the subject of this release, including in the conference call referenced herein, contain forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo assumes, plans, expects, believes, intends, projects, indicates, enables, transforms, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. This press release and any accompanying disclosures may include or reference certain forward-looking, non-GAAP financial measures, such as free cash flow, and certain related estimates regarding future performance, results and financial position. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, long-term performance of wells, drilling and operating risks, the increase in service and supply costs, tariffs on steel, pipeline transportation constraints in the Permian Basin, hedging activities, possible impacts of litigation and regulations and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, and those set forth from time to time in other filings with the Securities and Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2019, to be filed with the SEC. These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this press release and the conference call, the Company may use the terms "resource potential" and "estimated ultimate recovery," "type curve" or "EURs," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling and production costs, availability and cost of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. EURs from reserves may change significantly as development of the

Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The "standardized measure" of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company's proved reserves.

Unless otherwise specified, references to "average sales price" refer to average sales price excluding the effects of our derivative transactions. All amounts, dollars and percentages presented in this press release are rounded and therefore approximate.

Laredo Petroleum, Inc.
Selected operating data

	Three months ended December 31,		Year ended December 31, 2019	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,511	2,571	10,376	10,175
NGL (MBbl)	2,475	1,931	9,118	7,259
Natural gas (MMcf)	16,438	11,983	60,169	44,680
Oil equivalents (MBOE)(1)(2)	7,725	6,500	29,522	24,881
Average daily oil equivalent sales volumes (BOE/D)(2)	83,968	70,653	80,883	68,168
Average daily oil sales volumes (Bbl/D)(2)	27,296	27,949	28,429	27,878
Average sales prices(2):				
Oil ($/Bbl)(3)	$ 56.55	$ 52.59	$ 55.21	$ 59.48
NGL ($/Bbl)(3)	$ 10.26	$ 17.53	$ 11.00	$ 20.64
Natural gas ($/Mcf)(3)	$ 0.74	$ 0.63	$ 0.55	$ 1.20
Average sales price ($/BOE)(3)	$ 23.24	$ 27.18	$ 23.93	$ 32.50
Oil, with commodity derivatives ($/Bbl)(4)	$ 56.79	$ 49.55	$ 54.37	$ 55.49
NGL, with commodity derivatives ($/Bbl)(4)	$ 13.02	$ 17.47	$ 13.61	$ 20.03
Natural gas, with commodity derivatives ($/Mcf)(4)	$ 0.94	$ 1.74	$ 1.05	$ 1.77
Average sales price, with commodity derivatives ($/BOE)(4)	$ 24.62	$ 28.01	$ 25.45	$ 31.72
Average selected costs and expenses per BOE sold(2):				
Lease operating expenses	$ 2.84	$ 3.51	$ 3.08	$ 3.67
Production and ad valorem taxes	1.43	1.73	1.38	1.99
Transportation and marketing expenses	1.32	0.79	0.86	0.47
Midstream service expenses	0.14	0.16	0.15	0.12
General and administrative:				
Cash	1.33	2.08	1.57	2.40
Non-cash stock-based compensation, net(5)	0.39	1.18	0.28	1.46
Depletion, depreciation and amortization	8.78	9.29	9.00	8.55
Total selected costs and expenses	$ 16.23	$ 18.74	$ 16.32	$ 18.66
Average cash margins per BOE sold(2)(6):				
Without derivatives	$ 16.18	$ 18.91	$ 16.89	$ 23.85
With commodity derivatives	$ 17.56	$ 19.74	$ 18.41	$ 23.07

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

(3) Price reflects the average of actual sales prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point.

(4) Price reflects the after-effects of our commodity derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured commodity derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to commodity derivatives that settled during the respective periods.

(5) For the year ended December 31, 2019, non-cash stock-based compensation, net, excluding forfeitures related to our organizational restructuring, on a per BOE sold basis was $0.66.

(6) For each period presented, on a per BOE sold basis, average cash margin is calculated as average sales price less (i) lease operating expenses, (ii) production and ad valorem taxes, (iii) transportation and marketing expenses, (iv) midstream service expenses and (v) cash general and administrative.

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

	Three months ended December 31,		Year ended December 31, 2019	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 179,558	$ 176,671	$ 706,548	$ 808,530
Midstream service revenues	3,356	2,397	11,928	8,987
Sales of purchased oil	35,208	36,219	118,805	288,258
Total revenues	218,122	215,287	837,281	1,105,775
Costs and expenses:				
Lease operating expenses	21,948	22,823	90,786	91,289
Production and ad valorem taxes	11,080	11,225	40,712	49,457
Transportation and marketing expenses	10,164	5,134	25,397	11,704
Midstream service expenses	1,085	1,048	4,486	2,872
Costs of purchased oil	39,034	36,222	122,638	288,674
General and administrative	13,302	21,182	54,729	96,138
Organizational restructuring expenses	—	—	16,371	—
Depletion, depreciation and amortization	67,846	60,399	265,746	212,677
Impairment expense	222,999	—	620,889	—
Other operating expenses	1,041	1,131	4,118	4,472
Total costs and expenses	388,499	159,164	1,245,872	757,283
Operating income (loss)	(170,377)	56,123	(408,591)	348,492
Non-operating income (expense):				
Gain (loss) on derivatives, net	(57,562)	112,195	79,151	42,984
Interest expense	(15,044)	(15,117)	(61,547)	(57,904)
Litigation settlement	—	—	42,500	—
Other, net	(514)	(766)	3,440	(4,728)
Total non-operating income (expense), net	(73,120)	96,312	63,544	(19,648)
Income (loss) before income taxes	(243,497)	152,435	(345,047)	328,844
Income tax benefit (expense):				
Current	—	426	—	807
Deferred	1,776	(3,288)	2,588	(5,056)
Total income tax benefit (expense)	1,776	(2,862)	2,588	(4,249)
Net income (loss)	$ (241,721)	$ 149,573	$ (342,459)	$ 324,595
Net income (loss) per common share:				
Basic	$ (1.04)	$ 0.65	$ (1.48)	$ 1.40
Diluted	$ (1.04)	$ 0.65	$ (1.48)	$ 1.39
Weighted-average common shares outstanding:				
Basic	231,718	229,700	231,295	232,339
Diluted	231,718	230,190	231,295	233,172

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

	Three months ended December 31,		Year ended December 31, 2019	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income (loss)	$ (241,721)	$ 149,573	$ (342,459)	$ 324,595
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash stock-based compensation, net	3,046	7,648	8,290	36,396
Depletion, depreciation and amortization	67,846	60,399	265,746	212,677
Impairment expense	222,999	—	620,889	—
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	57,562	(112,195)	(79,151)	(42,984)
Settlements received for matured commodity derivatives, net	14,394	12,033	63,221	6,090
Settlements paid for early terminations of commodity derivatives, net	—	—	(5,409)	—
Premiums paid for commodity derivatives	(1,399)	(5,405)	(9,063)	(20,335)
Deferred income tax (benefit) expense	(1,776)	3,288	(2,588)	5,056
Other, net	6,996	3,544	21,791	15,882
Cash flows from operating activities before changes in operating assets and liabilities, net	127,947	118,885	541,267	537,377
Change in current assets and liabilities, net	(15,818)	10,842	(64,123)	1,157
Change in noncurrent assets and liabilities, net	(3,923)	(451)	(2,070)	(730)
Net cash provided by operating activities	108,206	129,276	475,074	537,804
Cash flows from investing activities:				
Acquisitions of oil and natural gas properties, net of closing adjustments	(196,404)	(1,198)	(199,284)	(17,538)
Capital expenditures:				
Oil and natural gas properties	(90,803)	(151,114)	(458,985)	(673,584)
Midstream service assets	(1,169)	(1,020)	(7,910)	(6,784)
Other fixed assets	(713)	(1,363)	(2,433)	(7,308)
Proceeds from dispositions of capital assets, net of selling costs	54	170	6,901	14,258
Net cash used in investing activities	(289,035)	(154,525)	(661,711)	(690,956)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	195,000	20,000	275,000	210,000
Payments on Senior Secured Credit Facility	(5,000)	—	(90,000)	(20,000)
Share repurchases	—	—	—	(97,055)
Other, net	(7)	(7)	(2,657)	(6,801)
Net cash provided by financing activities	189,993	19,993	182,343	86,144
Net increase (decrease) in cash and cash equivalents	9,164	(5,256)	(4,294)	(67,008)
Cash and cash equivalents, beginning of period	31,693	50,407	45,151	112,159
Cash and cash equivalents, end of period	$ 40,857	$ 45,151	$ 40,857	$ 45,151

Laredo Petroleum, Inc.
Total Costs Incurred

The following table presents the components of our costs incurred, excluding non-budgeted acquisition costs:

(in thousands)	Three months ended December 31, 2019	Three months ended December 31, 2018	Year ended December 31, 2019 2019	Year ended December 31, 2019 2018
	(unaudited)		(unaudited)	
Oil and natural gas properties	$ 104,616	$ 145,345	$ 470,455	$ 631,674
Midstream service assets	1,071	969	8,655	4,618
Other fixed assets	504	1,125	2,470	7,322
Total costs incurred, excluding non-budgeted acquisition costs	$ 106,191	$ 147,439	$ 481,580	$ 643,614

Laredo Petroleum, Inc.
Supplemental reconciliations of GAAP to non-GAAP financial measures

Non-GAAP financial measures

The non-GAAP financial measures of Free Cash Flow, Adjusted Net Income and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP financial measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flows from operating activities. Free Cash Flow, Adjusted Net Income and Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Free Cash Flow (Unaudited)

Free Cash Flow, a non-GAAP financial measure, does not represent funds available for future discretionary use because it excludes funds required for future debt service, capital expenditures, acquisitions, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating operating trends in our business that are affected by production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flows from operating activities before changes in operating assets and liabilities, net, less costs incurred, excluding non-budgeted acquisition costs, for the calculation of Free Cash Flow (non-GAAP):

	Three months ended December 31,		Year ended December 31, 2019	
(in thousands)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 108,206	$ 129,276	$ 475,074	$ 537,804
Less:				
(Increase) decrease in current assets and liabilities, net	(15,818)	10,842	(64,123)	1,157
Increase in noncurrent assets and liabilities, net	(3,923)	(451)	(2,070)	(730)
Cash flows from operating activities before changes in operating assets and liabilities, net	127,947	118,885	541,267	537,377
Less costs incurred, excluding non-budgeted acquisition costs:				
Oil and natural gas properties(1)	104,616	145,345	470,455	631,674
Midstream service assets	1,071	969	8,655	4,618
Other fixed assets	504	1,125	2,470	7,322
Total costs incurred, excluding non-budgeted acquisition costs	106,191	147,439	481,580	643,614
Free Cash Flow (non-GAAP)	$ 21,756	$ (28,554)	$ 59,687	$ (106,237)

(1) Includes non-cash stock-based compensation, net of $1.3 million and $1.9 million for the three months ended December 31, 2019 and 2018, respectively, and $4.5 million and $7.9 million for the years ended December 31, 2019 and 2018, respectively. Additionally, includes asset retirement costs of $0.1 million and $0.2 million for the three months ended December 31, 2019 and 2018, respectively, and $0.6 million and $0.7 million for the years ended December 31, 2019 and 2018, respectively.

Adjusted Net Income (Unaudited)

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to income taxes, mark-to-market on derivatives, premiums paid for derivatives, impairment expense, gains or losses on disposal of assets and other non-recurring income and expenses and after applying adjusted income tax expense. We believe Adjusted Net Income helps investors in the oil and natural gas industry to measure and compare our performance to other oil and natural gas companies by excluding from the calculation items that can vary significantly from company to company depending upon accounting methods, the book value of assets and other non-operational factors.

The following table presents a reconciliation of income (loss) before income taxes (GAAP) to Adjusted Net Income (non-GAAP):

	Three months ended December 31,		Year ended December 31, 2019	
(in thousands, except per share data)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Income (loss) before income taxes	$ (243,497)	$ 152,435	$ (345,047)	$ 328,844
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	57,562	(112,195)	(79,151)	(42,984)
Settlements received for matured commodity derivatives, net	14,394	12,033	63,221	6,090
Settlements paid for early terminations of commodity derivatives, net	—	—	(5,409)	—
Premiums paid for commodity derivatives	(1,399)	(5,405)	(9,063)	(20,335)
Organizational restructuring expenses	—	—	16,371	—
Impairment expense	222,999	—	620,889	—
Litigation settlement	—	—	(42,500)	—
(Gain) loss on disposal of assets, net	(67)	1,207	248	5,798
Write-off of debt issuance costs	935	—	935	—
Adjusted income before adjusted income tax expense	50,927	48,075	220,494	277,413
Adjusted income tax expense(1)	(11,204)	(10,577)	(48,509)	(61,031)
Adjusted Net Income	$ 39,723	$ 37,498	$ 171,985	$ 216,382
Net income (loss) per common share:				
Basic	$ (1.04)	$ 0.65	$ (1.48)	$ 1.40
Diluted	$ (1.04)	$ 0.65	$ (1.48)	$ 1.39
Adjusted Net Income per common share:				
Basic	$ 0.17	$ 0.16	$ 0.74	$ 0.93
Diluted	$ 0.17	$ 0.16	$ 0.74	$ 0.93
Adjusted diluted	$ 0.17	$ 0.16	$ 0.74	$ 0.93
Weighted-average common shares outstanding:				
Basic	231,718	229,700	231,295	232,339
Diluted	231,718	230,190	231,295	233,172
Adjusted diluted	231,828	230,190	231,897	233,172

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for each of the periods ended December 31, 2019 and 2018.

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for non-cash stock-based compensation, net, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid for commodity derivatives, accretion expense, gains or losses on disposal of assets, write-off of debt issuance costs, interest expense, income taxes and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because it excludes funds required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items that can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss and the lack of comparability of results of operations to different companies due to the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended December 31,		Year ended December 31, 2019	
(in thousands)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Net income (loss)	$ (241,721)	$ 149,573	$ (342,459)	$ 324,595
Plus:				
Non-cash stock-based compensation, net	3,046	7,648	8,290	36,396
Depletion, depreciation and amortization	67,846	60,399	265,746	212,677
Impairment expense	222,999	—	620,889	—
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	57,562	(112,195)	(79,151)	(42,984)
Settlements received for matured commodity derivatives, net	14,394	12,033	63,221	6,090
Settlements paid for early terminations of commodity derivatives, net	—	—	(5,409)	—
Premiums paid for commodity derivatives	(1,399)	(5,405)	(9,063)	(20,335)
Accretion expense	1,041	1,131	4,118	4,472
(Gain) loss on disposal of assets, net	(67)	1,207	248	5,798
Write-off of debt issuance costs	935	—	935	—
Interest expense	15,044	15,117	61,547	57,904
Organizational restructuring expenses	—	—	16,371	—
Litigation settlement	—	—	(42,500)	—
Income tax (benefit) expense	(1,776)	2,862	(2,588)	4,249
Adjusted EBITDA	$ 137,904	$ 132,370	$ 560,195	$ 588,862

Projected Free Cash Flow

Projected Free Cash Flow, a non-GAAP financial measure, is calculated as estimated cash flows from operating activities before changes in assets and liabilities, less estimated costs incurred, excluding non-budgeted acquisition costs, made during the period. Management believes this is useful to management and investors in evaluating the operating trends in its business due to production, commodity prices, operating costs and other related factors.

# # #

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EXHIBIT 99.2

L A R E D O P E T R O L E U M
Fourth-Quarter & Full-Year 2019 Earnings Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes, intends, projects, indicates, enables, transforms, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, long-term performance of wells, drilling and operating risks, the increase in service and supply costs, tariffs on steel, pipeline transportation constraints in the Permian Basin, hedging activities, possible impacts of litigation and regulations, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018 and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2019, to be filed with the SEC. These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "resource potential," "estimated ultimate recovery" ("EURs") or "type curve," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The "standardized measure" of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company's proved reserves.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA, Cash Flow and Free Cash Flow. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA, Cash Flow and Free Cash Flow to the nearest comparable measure in accordance with GAAP, please see the Appendix.

Unless otherwise specified, references to "average sales price" refer to average sales price excluding the effects of our derivative transactions. All amounts, dollars and percentages presented in this presentation are rounded and therefore approximate.

Surpassing Guidance on Production & Expenses

4Q-19 Select Results

Production

Oil Production
27.3 MBO/d
5% beat vs guidance

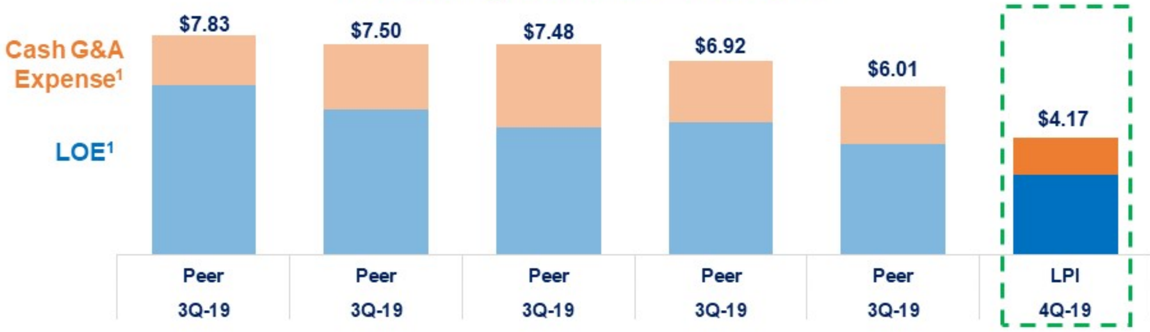
Total Production
84.0 MBOE/d
10% beat vs guidance

Controllable Cash Costs

Lease Operating Expense
$2.84/BOE
11% beat vs guidance

G&A Cash Expense
$1.33/BOE
17% beat vs guidance

Peer-Leading Controllable Cash Costs



[1]Representative of unit expenses; Peers include: CDEV, CPE, MTDR, QEP, SM

Successful Transition to Returns-Focused Strategy in 2019

2019

Management transition complete, executing on strategy

FREE CASH FLOW[1]
Generated $60 MM in 2019

OIL PRODUCTION
Above guidance for four consecutive quarters

PROVED RESERVES
Oil growth of 27% YoY & total reserves growth of 23% YoY

ACQUISTIONS
Executed two high-margin, oily acquisitions while maintaining a competitive leverage ratio

LOW-COST OPERATIONS
Remain among the lowest cost operator vs peers on controllable cash costs[2] and Midland Basin per well D&C[3]

[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow
[2]Representative of unit expenses; Peer data as of 3Q-19 and includes: CDEV, CPE, MTDR, QEP, SM
[3]Source: RSEG 1-21-20 2019 average lateral cost per foot. Peers include: APA, CPE, CVX, CXO, ECA, ESTE, FANG, OXY, PE, PXD, QEP, SM and XOM

Pivoted Strategy to Increase Stakeholder Value

Target consistent Free Cash Flow[1] generation and oil growth per net debt-adjusted share

Continuous	In Process	Opportunistic
Optimize existing acreage	**Improve corporate returns through accretive acquisitions**	**Increase scale through consolidation**
High-grade development to maximize oil productivity	Opportunistically target high-margin inventory	Combine operations to eliminate redundancies
+	+	+
Maintain capital and operational cost advantages	Utilize Free Cash Flow[1] to maintain a competitive leverage profile	Leverage basin-leading low cost structure to achieve synergies
=	=	=
Improves capital efficiency on existing acreage	Accelerates Cash Flow[1] & oil growth	Delivers increased return of cash to stakeholders

[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow and Cash Flow

Disciplined Acquisition Strategy, Committed to a Strong Balance Sheet

Target consistent Free Cash Flow[1] generation and oil growth per net debt-adjusted share

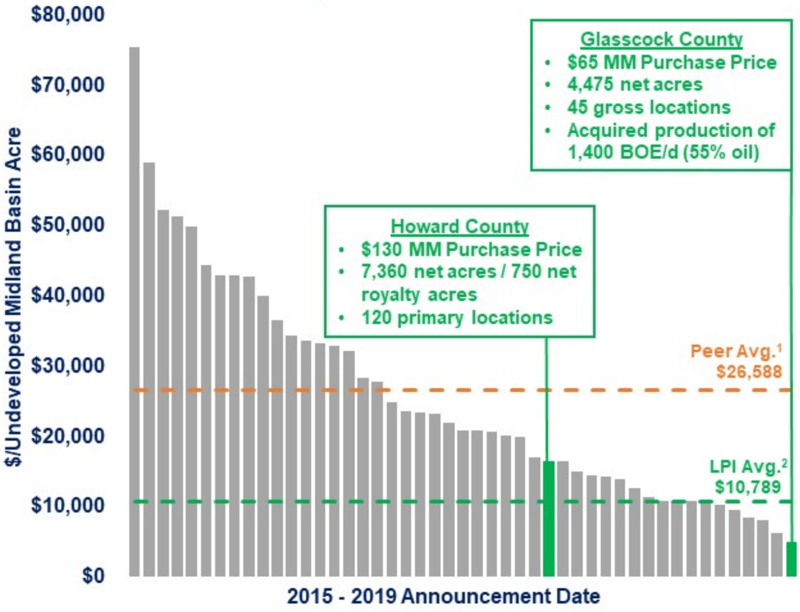
- High-margin, higher-return (50+% oil) inventory
- Contiguous Midland Basin acreage positioned to benefit from LPI's peer-leading operational costs and efficiencies
- Utilize Free Cash Flow[1] to drive long-term target leverage ratio to a level at or below pre-acquisitions level

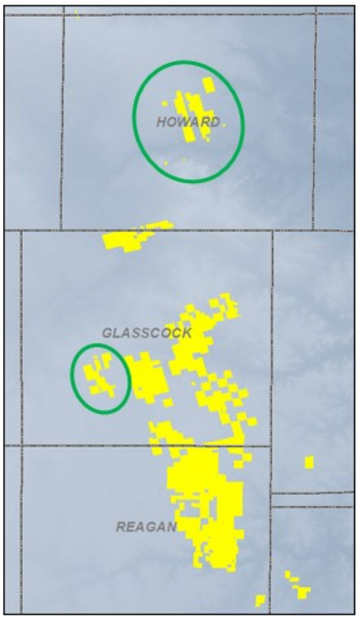
Net Debt to TTM Adjusted EBITDA[2]

[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow; [2]Peers are as of 3Q-19, and peers include CDEV, CPE PF (pro forma for the CRZO acquisition), MTDR, OAS, QEP, and SM. Peer company Net Debt is calculated using each peer company's cash, total debt and preferred equity as of 9-30-19 as they appear in such peer company's public filings (note: CPE is presented pro forma for the CRZO acquisition). Peer company TTM Adjusted EBITDA is as of 9-30-19 as presented in each company's public filings. Net Debt and Adjusted EBITDA are non-GAAP financial measures, and each company's calculation of Adjusted EBITDA may therefore not be directly comparable to that of another company's. LPI includes FY-19 TTM Adjusted EBITDA and net debt as of 2-11-20

Laredo's Recent Acquisitions at Discount to Precedent Trades

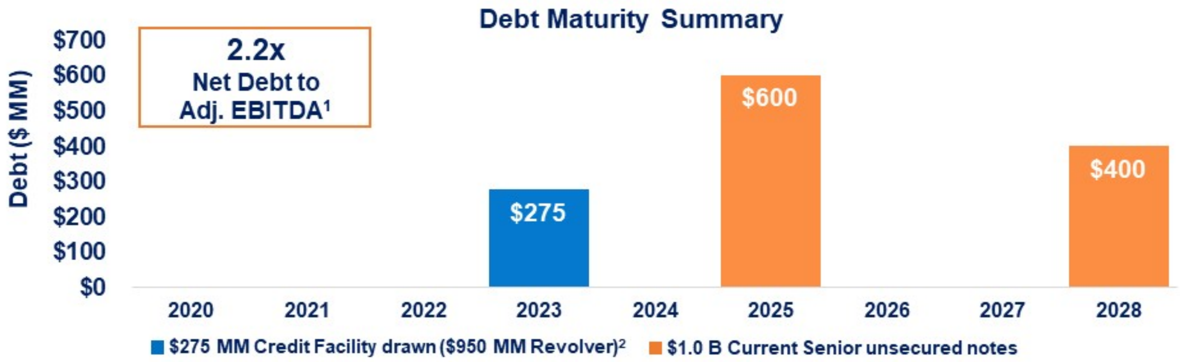
Focused on employing a disciplined approach to acquisition economic evaluation

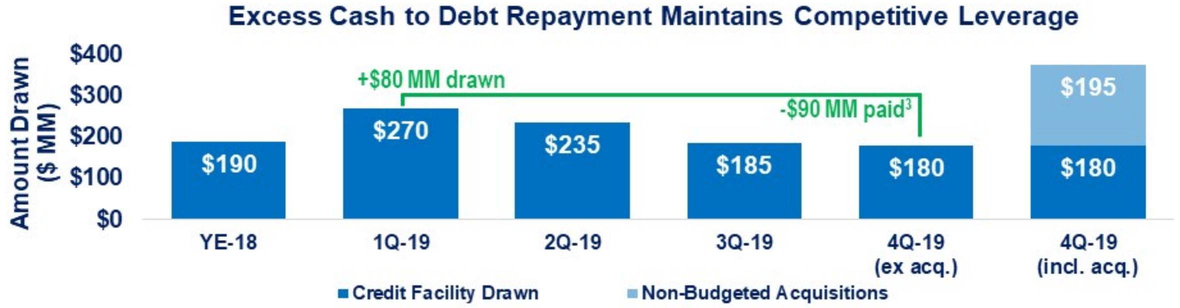




Note: Data from company disclosures and Enverus as of 12-11-19
[1]Includes all Midland basin transactions >$50 MM since 1-1-15
[2]Average of recently announced Glasscock and Howard acquisitions

Demonstrated Discipline Preserves Competitive Leverage





[1]See Appendix for reconciliations of non-GAAP measures and the calculations of Net Debt to Adjusted EBITDA and Free Cash Flow; Includes TTM Adjusted EBITDA as of 12-31-19 and net debt as of 2-11-20; [2]LPI issued $1 B of new senior unsecured notes in Jan-20, with the net proceeds to be used to redeem its previously-existing $800 MM of outstanding senior unsecured notes and to partially repay its senior unsecured credit facility. In conjunction with the closing of the notes issuance, LPI's borrowing base in place under its Fifth Amended and Restated Senior Secured Credit Facility was reduced to ~$950 MM; Amount drawn is as of 2-11-20; [3]Excluding non-budgeted acquisitions

Hedging Strategy Reduces Impact of Commodity Price Fluctuations

2020 Vol Hedged[2]

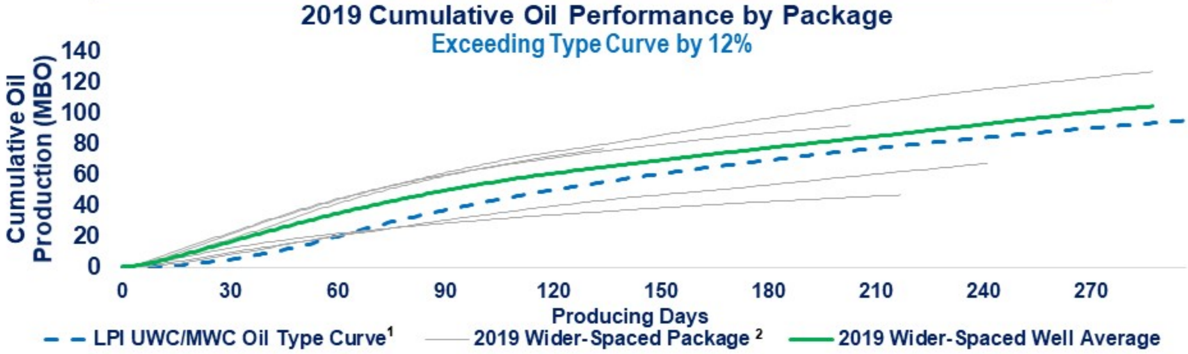
WTI:	Brent:	Natural Gas:	Waha Basis:
7,173,600 BO	2,379,000 BO	23,790,000 MMBtu	32,574,000 MMBtu

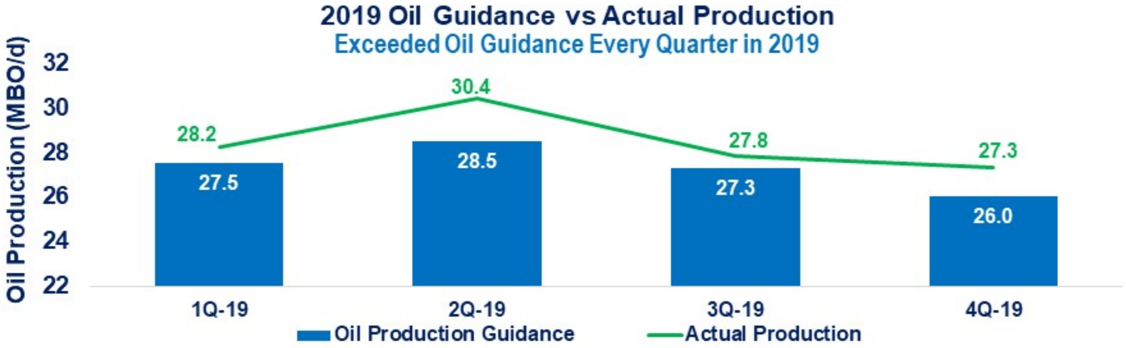
	2020 Volume Hedged[2] (gal)	Strip[1] ($/gal)	LPI ($/gal)
Ethane	15,372,000	$0.14	$0.32
Propane	52,264,800	$0.43	$0.63
Normal Butane	18,446,400	$0.56	$0.68
Iso Butane	4,611,600	$0.61	$0.71
Natural Gasoline	16,909,200	$1.00	$1.08

$150+ MM hedge income at $50/BO WTI & $2.25/MMBtu HH

[1]Strip as of 2-10-20
[2]2020 volume hedged as of 2-11-20
Note: LPI representative of weighted-average price for the period presented

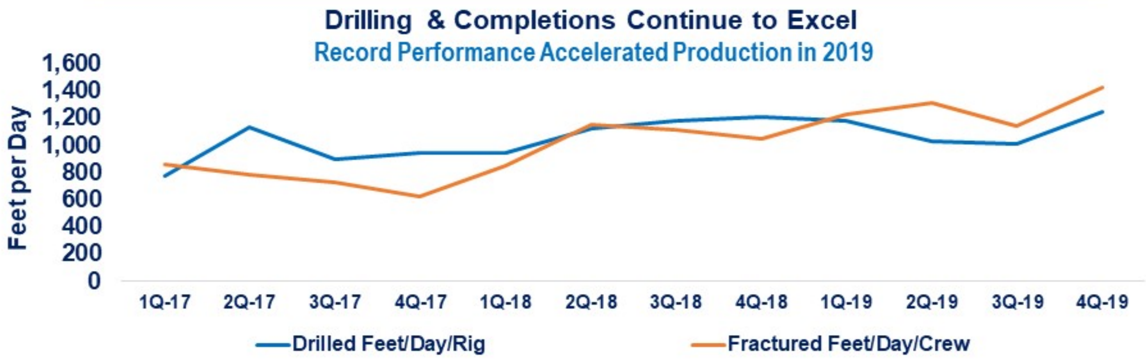
Wider-Spaced Packages Support Consistent Oil Outperformance

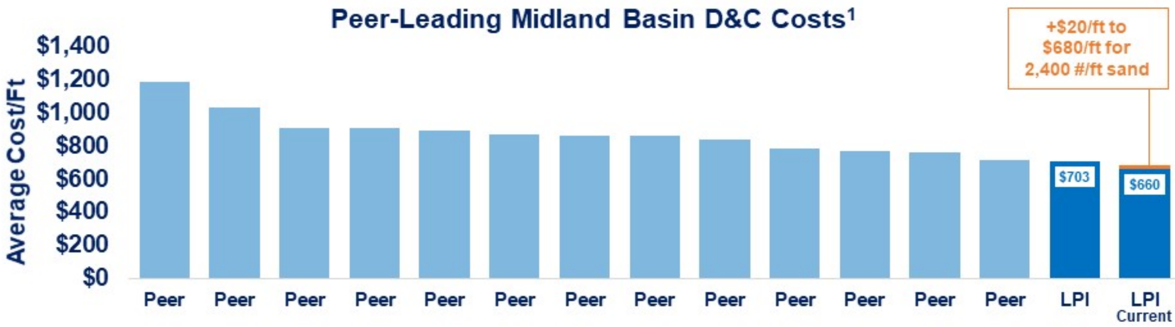




[1]UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor
[2]Includes an average of the Yellow Rose package (8 wells), Hoelscher package (4 wells), Frysak/Halfmann (4 wells), Sugg-B (7 wells), Von Gonten package (9 wells) & Driver-Agnell package (6 wells); All wells show cumulative oil production, normalized to a 10,000' lateral, as of 2-6-20

Operational Efficiencies Drive Peer-Leading Capital Costs





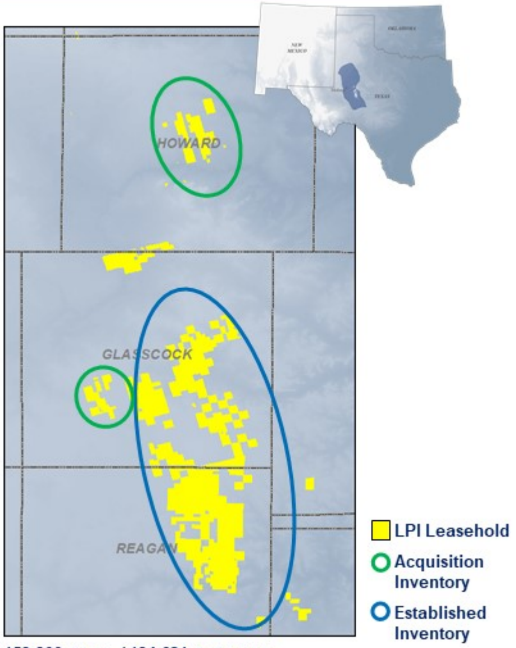
[1]Source: RSEG 1-21-2020 2019 average lateral cost per foot. Peers include: APA, CPE, CVX, CXO, ECA, ESTE, FANG, OXY, PE, PXD, QEP, SM and XOM; LPI Current per internal data

Acquisitions Add Oily, High-Margin Inventory

Total Inventory (Acquired + Established)	
Inventory	Inventory Years
655 - 825	12.5

Acquired Inventory Lower Spraberry/UWC/MWC	
Inventory	Inventory Years
175	3

Established Inventory UWC/MWC	
Inventory	Inventory Years
350 - 500	7
Cline	
Inventory	Inventory Years
140 - 160	2.5

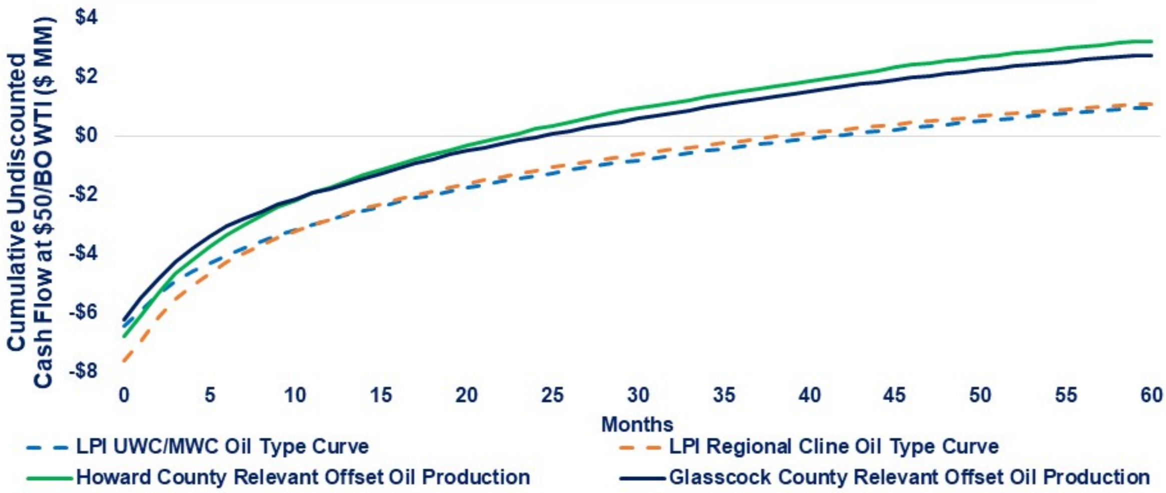


153,300 gross / 134,621 net acres

Acquired locations move to front of drill schedule

Note: Inventory expected to average oil type curve productivity
Inventory Years is calculated as Inventory divided by 60 wells per year

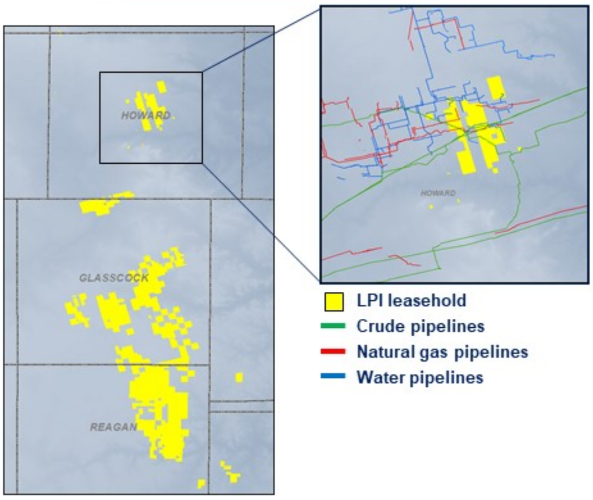
Acquisitions Support Oil Growth & Free Cash Flow[1] Generation



	Established UWC/MWC Oil Type Curve		Established Cline Oil Type Curve		Glasscock County Acquisition Relevant Offset Oil Production		Howard County Acquisition Relevant Offset Oil Production	
WTI ($/BO)	$50	$55	$50	$55	$50	$55	$50	$55
24 Mo. Cumulative Oil (MBO)	148	148	186	186	202	202	232	232
ROR (%)	20%	28%	19%	28%	37%	51%	39%	54%
Payback Period (Months)	43	33	40	29	26	20	24	19

[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow
Note: Utilizes $2.25/MMBtu HH

Successfully Transitioning to Howard County



- **Operations transition is currently under way:**
  - **Two of four drilling rigs in Howard County, with third expected in Mar-20**
  - **First well of 15-well package has been drilled, completions beginning in 2Q-20E**
- **Current negotiations with multiple third-party service infrastructure providers indicate service costs similar to the established acreage**

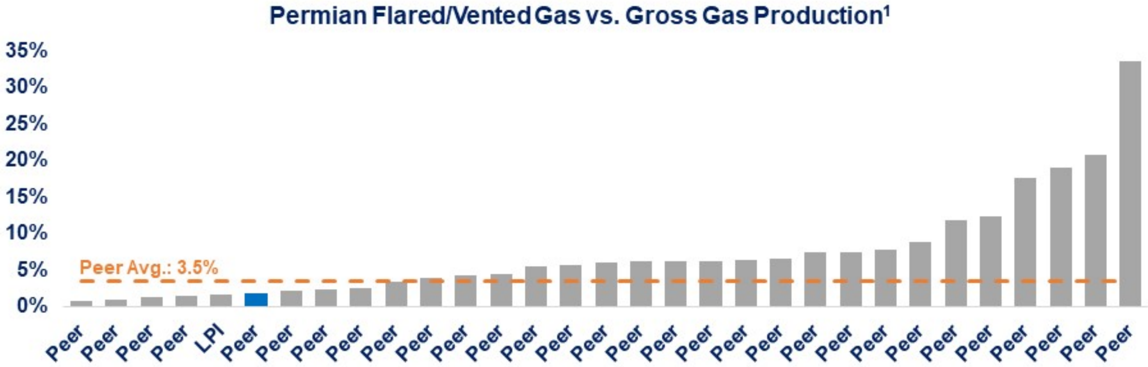
Howard County Acquisitions	#1	#2	Current Net Total
Purchase Price ($ MM)	$130[1]	$22.5	$155.5
Net Acres	7,360	1,100	8,380
Net Royalty Acres	750	0	750
Gross Locations	120	10	130
Net Locations	100	24	124
Closing Date	Dec-19	Feb-20	

Acquisition prices are well below historic Howard County averages, with potential for additional bolt-on acquisitions

LAREDO PETROLEUM

[1]Pursuant to the terms of the purchase agreement, if the average WTI crude price exceeds $60/BO for the year ending 12-31-20, the Company is obligated to pay the seller $20 MM

Prioritizing the Environment in Our Operations



[1]Source: Rystad Energy as of 2-10-20, with data beginning as of January 2018; Peers include: APA, AXAS, BP, CDEV, COP, CPE, CVX, CXO, DVN, EOG, FANG, HALC, LLEX, MRO, MTDR, NBL, OAS, OVV, OXY, PDCE, PE, PXD, QEP, REI, ROSE, RYDAF, SM, WPX, XEC and XOM

Infrastructure Protects the Environment & Enhances Economics

LPI In-Place Infrastructure

60 Miles
Crude oil gathering pipelines

54 MBWPD
Produced water recycling capacity

110 Miles
Water gathering & distribution pipelines

170 miles
Natural gas gathering and distribution pipelines

Environmental Impact

Additional gas sold vs. vented/flared	Barrels of recycled water utilized in completions	Truckloads eliminated from the field
>2.4 Bcf	>11,500,000	>250,000

Net Shareholder Value[1]

$0.57/BOE
Reduction in unit LOE, helping to control operating costs

$175,000
Per well reduction in capital due to in-place water infrastructure

$3.7 MM
Revenue from natural gas sold versus vented/flared

[1]Net Shareholder Value calculated assuming 95% GWI / 75% NRI
Note: Existing infrastructure as of 1-1-20
Environmental impact and shareholder value include owned infrastructure and third-party contracts as of FY-19

APPENDIX

1Q-20 Guidance

Production:	
Total production (MBOE/d)	81.2 - 82.7
Oil production (MBbl/d)	26.8 - 27.3
Average sales price realizations: *(excluding derivatives)*	
Oil (% of WTI)	100%
NGL (% of WTI)	14%
Natural gas (% of Henry Hub)	13%
Other ($ MM):	
Net income / (expense) of purchased crude oil	($4.0)
Net midstream income / (expense)	$1.5
Operating costs & expenses ($/BOE):	
Lease operating expenses	$3.00
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	6.50%
Transportation and marketing expenses	$2.15
General and administrative expenses:	
Cash	$1.60
Non-cash stock-based compensation, net	$0.55
Depletion, depreciation and amortization	$9.00

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-20	FY-21
Oil total volume (Bbl)	9,552,600	1,460,000
Oil wtd-avg price ($/Bbl) - WTI	$59.50	
Oil wtd-avg price ($/Bbl) - Brent	$63.07	$60.16
Nat gas total volume (MMBtu)	23,790,000	14,052,500
Nat gas wtd-avg price ($/MMBtu) - HH	$2.72	$2.63
NGL total volume (Bbl)	2,562,000	2,202,775

Oil Swaps	FY-20	FY-21
WTI		
Volume (Bbl)	7,173,600	
Wtd-avg price ($/Bbl)	$59.50	
Brent		
Volume (Bbl)	2,379,000	1,460,000
Wtd-avg price ($/Bbl)	$63.07	$60.16

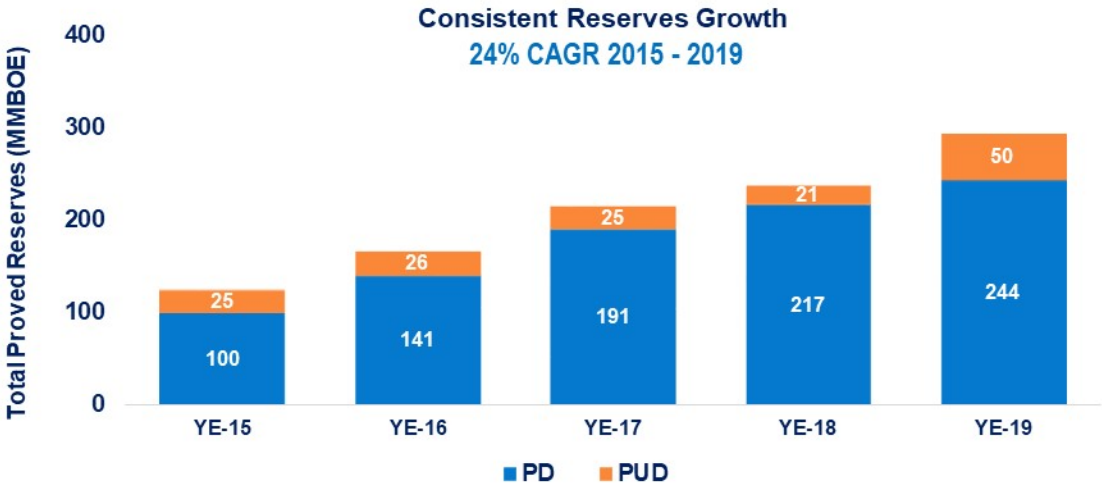
Natural Gas Swaps	FY-20	FY-21
HH		
Volume (MMBtu)	23,790,000	14,052,500
Wtd-avg price ($/MMBtu)	$2.72	$2.63

Basis Swaps	FY-20	FY-21
Waha/HH		
Volume (MMBtu)	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$0.76	-$0.47

Natural Gas Liquids Swaps	FY-20	FY-21
Ethane		
Volume (Bbl)	366,000	912,500
Wtd-avg price ($/Bbl)	$13.60	$12.01
Propane		
Volume (Bbl)	1,244,400	730,000
Wtd-avg price ($/Bbl)	$26.58	$25.52
Normal Butane		
Volume (Bbl)	439,200	255,500
Wtd-avg price ($/Bbl)	$28.69	$27.72
Isobutane		
Volume (Bbl)	109,800	67,525
Wtd-avg price ($/Bbl)	$29.99	$28.79
Natural Gasoline		
Volume (Bbl)	402,600	237,250
Wtd-avg price ($/Bbl)	$45.15	$44.31

Note: Open positions as of 1-1-20, hedges executed through 2-11-20
Natural gas liquids consist of Mt. Belvieu purity ethane and Mt. Belvieu non-TET propane, normal butane, isobutane, and natural gasoline

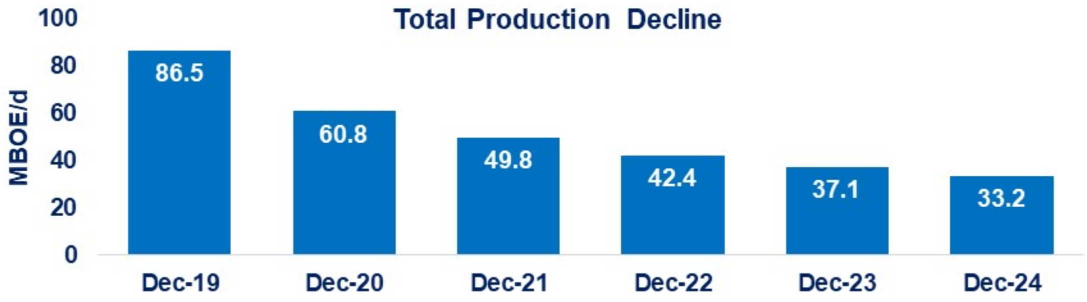
23% YoY Total Proved Reserves Growth in 2019

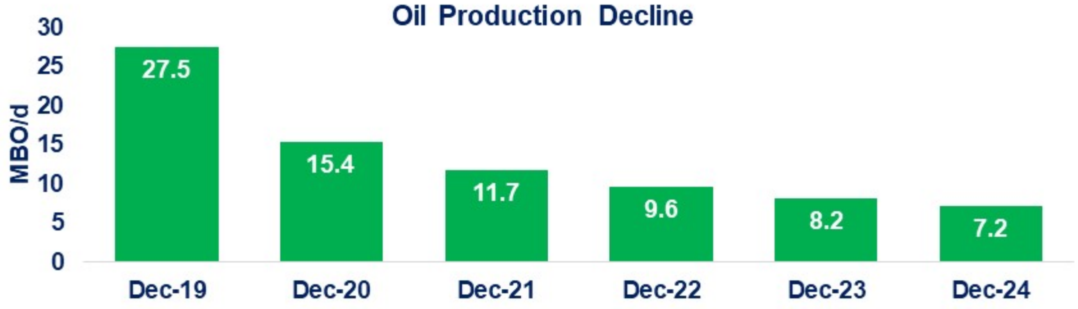


70% of YE-19 PUD locations booked in Howard County

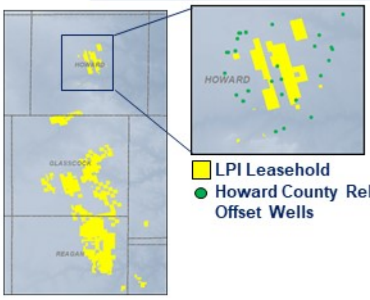
Note: YE-15 to YE-19 3-stream Reserves prepared by Ryder Scott

YE-19 Base Production Decline Expectations





Howard County Tier-One Acquisitions Deliver Higher-Margin Production



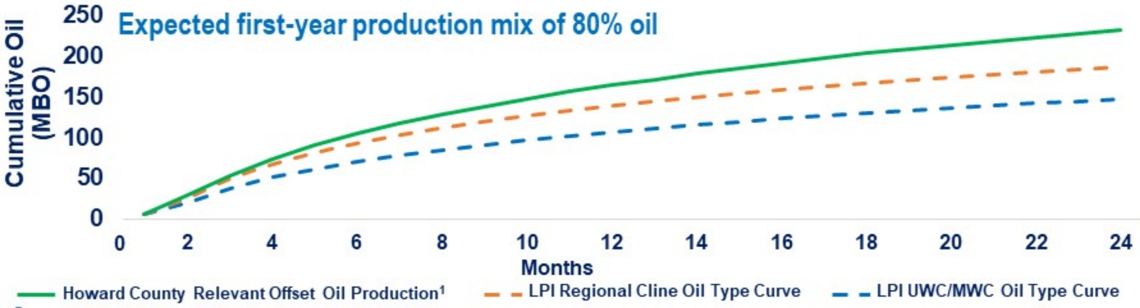
LPI Leasehold
Howard County Relevant Offset Wells

Acquisition prices are well below historic Howard County averages, with potential for additional bolt-on acquisitions

Howard County Acquisitions	#1	#2	Current Net Total
Purchase Price ($ MM)	$130[1]	$22.5	$155.5
Net Acres	7,360	1,100	8,380
Net Royalty Acres	750	0	750
Gross Locations	120	10	130
Net Locations	100	24	124
Closing Date	Dec-19	Feb-20	

Acquired Howard County Acreage Transforms Near-Term Drilling Plans

- Co-developing primarily as 16-well packages (4 LS & 12 UWC/MWC)
- Drilling began in early 1Q-20, with the first package completed in 3Q-20E

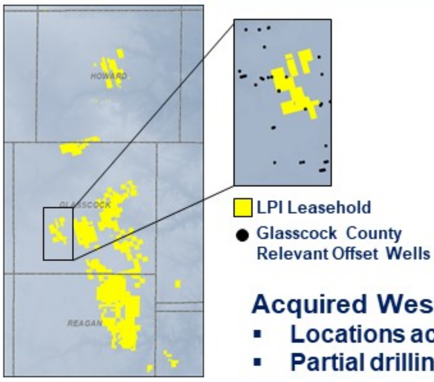


LAREDO PETROLEUM

[1]Pursuant to the terms of the purchase agreement, if the average WTI crude price exceeds $60/BO for the year ending 12-31-20, the Company is obligated to pay the seller $20 MM

[2]Howard County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus (as of 10-28-19)

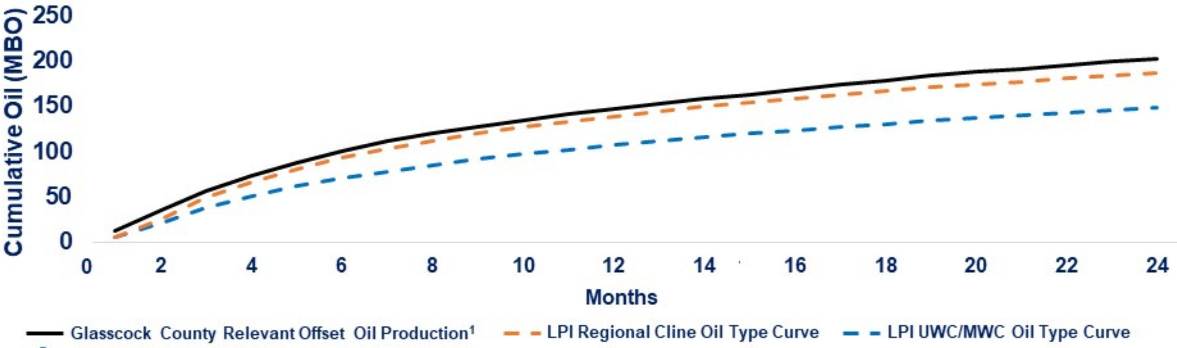
Bolt-On Glasscock County Acquisition Adds High-Return Inventory



W. Glasscock County Acquisition	Current Net Total
Purchase Price ($ MM)	$65
Net Acres	4,475
Net Production, BOE/d (% oil)	1,400 (55%)
Gross Locations	45
Net Locations	36
Closing Date	Dec-19

Acquired Western Glasscock Acreage Bolsters High-Margin Inventory

- Locations across LS & UWC/MWC formations
- Partial drilling expected in 2020 & 2021, with primary development in 2022

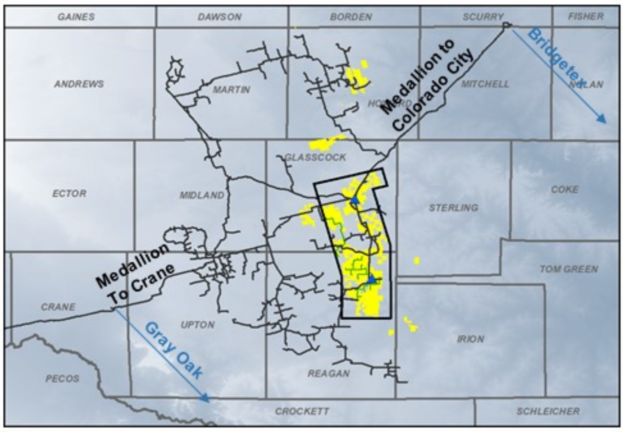


[1]Glasscock County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus and internal data (as of 10-28-19)

Oil Value Enhanced Via Gulf Coast Access

<u>Gross Physical Transportation Contracts:</u>

- **Medallion firm transportation secured for all crude oil produced within dedication area**
- **10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26 (USGC pricing)**
- **Firm transportation on Gray Oak upon full-service startup in 1Q-20E (Brent-related pricing):**
  - **Year 1: 25 MBOPD**
  - **Years 2 - 7: 35 MBOPD**



LPI leasehold
LMS truck stations
Medallion-dedicated LPI acreage
Medallion intra-basin pipelines
Long-haul pipelines
LMS oil gathering pipelines

Firm transportation to the US Gulf Coast provides exposure to Brent-based pricing for majority of crude oil production

LAREDO PETROLEUM

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income taxes, depletion, depreciation and amortization, impairment expense, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for future discretionary use because those funds are required for future debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure: is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors; helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting. There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended December 31,		Twelve months ended December 31,	
(in thousands, unaudited)	2019	2018	2019	2018
Net income (loss)	($241,721)	$149,573	($342,459)	$324,595
Plus:				
Non-cash stock based compensation, net	3,046	7,648	8,290	36,396
Depletion, depreciation and amortization	67,846	60,399	265,746	212,677
Impairment expense	222,999	-	620,889	-
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	57,562	(112,195)	(79,151)	(42,984)
Settlements received for matured derivatives, net	14,394	12,033	63,221	6,090
Settlements paid for early termination of commodity derivatives, net	-	-	(5,409)	-
Premiums paid for derivatives	(1,399)	(5,405)	(9,063)	(20,335)
Accretion expense	1,041	1,131	4,118	4,472
(Gain) Loss on disposal of assets, net	(67)	1,207	248	5,798
Write-off of debt issuance costs	935	-	935	-
Interest expense	15,044	15,117	61,547	57,904
Organizational restructuring expenses	-	-	16,371	-
Litigation settlement	-	-	(42,500)	-
Income tax (benefit) expense	(1,776)	2,862	(2,588)	4,249
Adjusted EBITDA	$137,904	$132,370	$560,195	$588,862

Supplemental Financial Calculations

Net debt to TTM Adjusted EBITDA

Net Debt to TTM Adjusted EBITDA is calculated as net debt divided by trailing twelve-month Adjusted EBITDA. Net debt is calculated as the face value of debt, reduced by cash and cash equivalents.

Net Debt to Adjusted EBITDA includes TTM Adjusted EBITDA ending 12-31-19 of $560 million and net debt as of 2-11-20. Net Debt as of 2-11-20 is calculated as the face value of debt of $1.275 billion, reduced by cash and cash equivalents of $67 million, which is net of expected cash to be used to redeem the remaining March 2023 Notes.

Net Debt to Adjusted EBITDA is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

See previous slide for a definition of Adjusted EBITDA and for a reconciliation of Net Income to Adjusted EBITDA.

Liquidity

Calculated as the Company's outstanding borrowings on its senior secured credit facility, less outstanding letters of credit, plus cash and cash equivalents.

Free Cash Flow

Free Cash Flow is a non-GAAP financial measure that does not represent funds available for future discretionary use because those funds are required for future debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating the operating trends in its business due to production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flows from operating activities before changes in assets and liabilities, net (non-GAAP), less costs incurred, excluding non-budgeted acquisition costs, for the calculation of Free Cash Flow (non-GAAP):

	Three months ended December 31,		Twelve months ended December 31,	
(in thousands, unaudited)	2019	2018	2019	2018
Net cash provided by operating activities	$108,206	$129,276	$475,074	$537,804
Less:				
Increase in current assets and liabilities, net	(15,818)	10,842	(64,123)	1,157
(Increase) decrease in noncurrent assets and liabilities, net	(3,923)	(451)	(2,070)	(730)
Cash flows from operating activities before changes in assets and liabilities, net ('Cash Flow')	127,947	118,885	541,267	537,377
Less costs incurred, excluding non-budgeted acquisition costs				
Oil and natural gas properties	104,616	145,345	470,455	631,674
Midstream service assets	1,071	970	8,655	4,618
Other fixed assets	504	1,124	2,470	7,322
Total costs incurred, excluding non-budgeted acquisition costs	106,191	147,439	481,580	643,614
Free Cash Flow	$21,756	($28,554)	$59,687	($106,237)