LAREDO PETROLEUM

September 2021 Investor 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, the ability of the Company to execute its strategies, including its ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to its financial results and to successfully integrate acquired businesses, assets and properties, oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries and other producing countries (“OPEC+”), the outbreak of disease, such as the coronavirus (“COVID-19”) pandemic, and any related government policies and actions, changes in domestic and global production, supply and demand for commodities, including as a result of the COVID-19 pandemic and actions by OPEC+, long-term performance of wells, drilling and operating risks, the increase in service and supply costs, tariffs on steel, pipeline transportation and storage constraints in the Permian Basin, the possibility of production curtailment, hedging activities, the impacts of severe weather, including the freezing of wells and pipelines in the Permian Basin due to cold weather, possible impacts of litigation and regulations, the impact of the Company’s transactions, if any, with its securities from time to time, the impact of new laws and regulations, including those regarding the use of hydraulic fracturing, the impact of new environmental, health and safety requirements applicable to the Company’s business activities, the possibility of the elimination of federal income tax deductions for oil and gas exploration and development and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2020, Current Report on Form 8-K, filed with the Securities and Exchange Commission ("SEC") on May 11, 2021, and those set forth from time to time in other filings 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. Any forward-looking statement speaks only as of the date on which such statement is made. Laredo does not intend to, and disclaims any obligation to, correct, update or revise 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,” “resource play,” “estimated ultimate recovery,” or “EURs,” “type curve” and “standardized measure,” 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 and “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, 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, 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. “Type curve” refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. The “standardized measure” of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. 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”), such as 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 definitions of such non-GAAP financial measures, please see the Appendix.

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

Laredo Petroleum: Pure-Play Permian Energy Producer

Laredo Petroleum (NYSE: LPI)	
Market Capitalization[1]	$956 Million
Enterprise Value[1]	$2.35 Billion
Net Acres	~148,000
2021E Production[2]	~78.5 MBOE/d
2021E Oil Production[2]	~31.0 MBO/d

Principles

Expand High-Margin Inventory

- Opportunistically acquire oil-weighted inventory
- High-grade development to maximize capital efficiency and increase oil cut

Manage Risk

- Target Free Cash Flow[3] generation and debt reduction
- Manage balance sheet and liquidity to facilitate optimal transaction financing
- Maintain a consistent commodity hedging program

Continuously Improve

- Focus on efficiencies and low-cost operations
- Reduce GHG emissions intensity and flaring

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[1]As of market close 9/3/2021; [2]Utilizes mid-point of FY-21 guidance; [3]See Appendix for definitions of non-GAAP financial measures

Rapidly Executing Transformational Strategy

- Oct 2019 Jason Pigott named CEO
- Nov 2019 Initial Howard County acquisition
- Dec 2019 W. Glasscock County acquisition
- Dec 2019 Craig Jarchow appointed to Board
- Jan 2020 $1 billion debt issuance
- Feb 2020 1st Howard County bolt-on transaction
- Feb 2020 Bill Albrecht appointed to Board
- May 2020 Bill Albrecht named Chairman
- Jun 2020 Bryan Lemmerman named CFO
- Aug 2020 Lisa Lambert appointed to Board
- Oct 2020 2nd Howard County bolt-on transaction
- Nov 2020 Jarvis Hollingsworth appointed to Board
- Nov 2020 Lori Lancaster appointed to Board
- Feb 2021 Publication of inaugural ESG report
- Feb 2021 Announced "at-the-market" Equity Program
- May 2021 Transformational acquisition of Sabalo and divestment of legacy working interest
- Jul 2021 $400 million debt issuance
- Jul 2021 Moody's upgrades senior unsecured notes to B3 from Caa1

Expand High-Margin Inventory

- Added ~37,500 net acres of oil-weighted leasehold in five separate transactions
- Divested ~94 million BOE of legacy low-margin, gas-weighted reserves
- Development focused on recently acquired oil-weighted inventory in Howard and W. Glasscock counties
- Oil cut expected to rise from 31% in 1Q-21 to ~50% by YE-22

Manage Risk

- No term-debt maturities until 2025
- Extended credit facility maturity to 2025
- Executed $75 million "at-the-market" equity program during 1H-21
- Active hedge program in 2022 to protect forecasted Free Cash Flow[1]
- Expect to reduce total leverage ratio to ~1.5x by YE-22

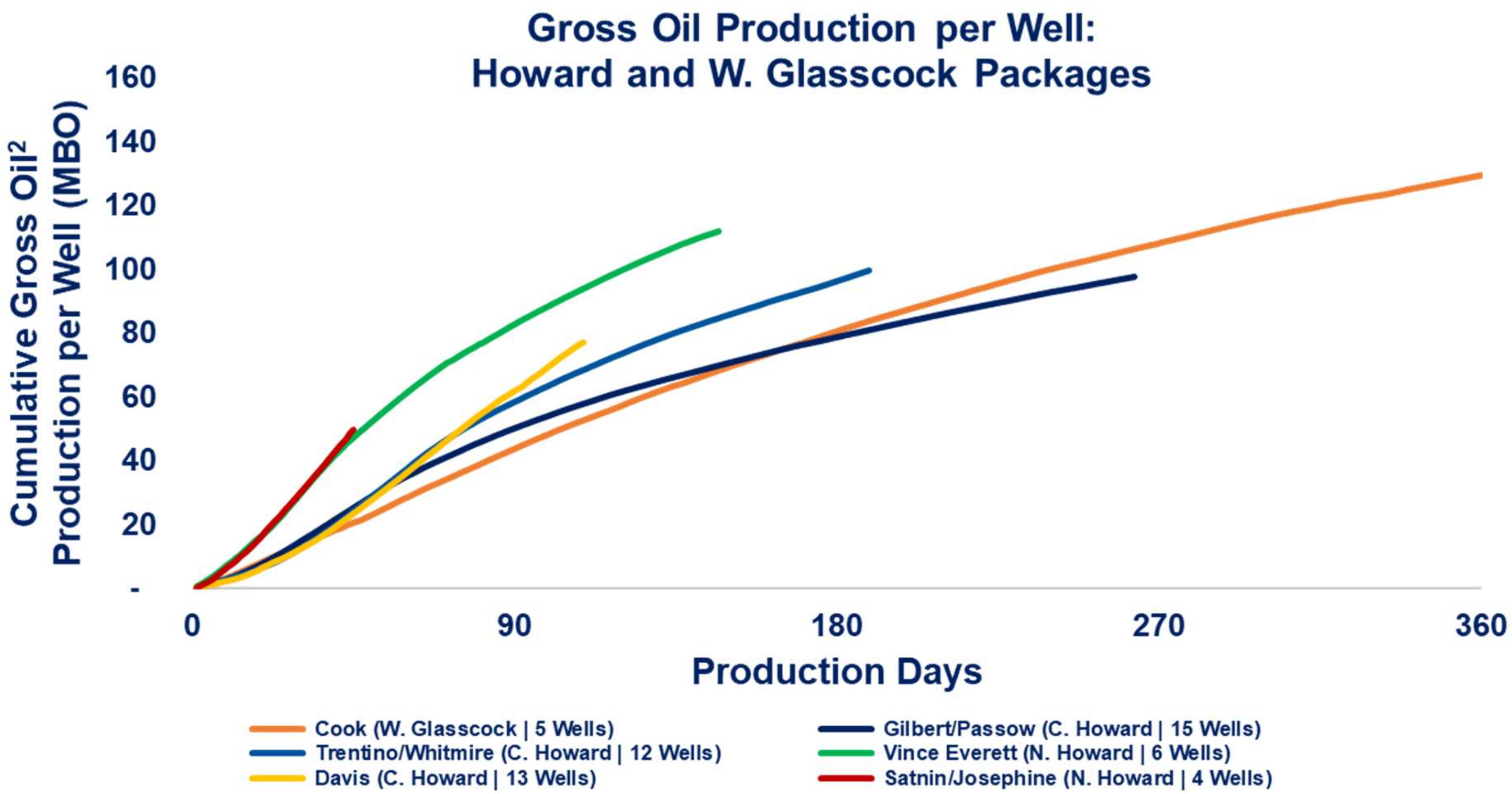
Continuously Improve

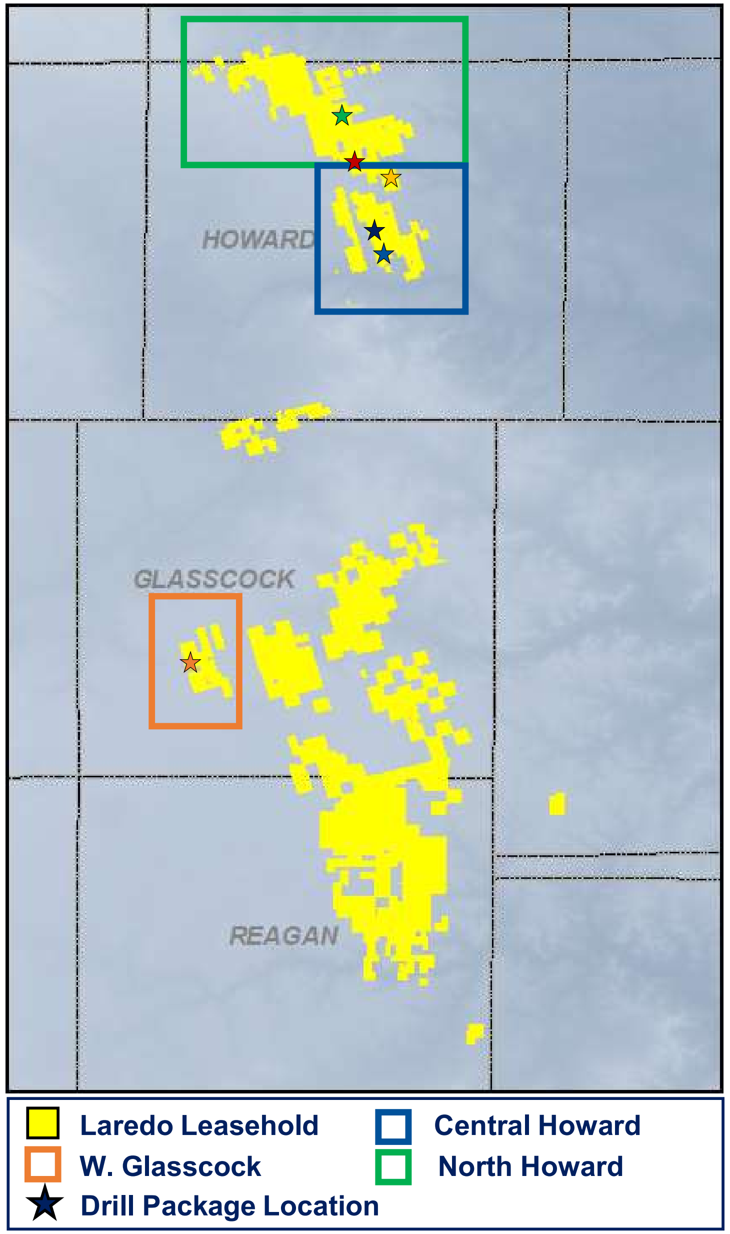
- Reduced percentage of produced natural gas flared/vented to 0.25% in 1H-21 from 0.71% for FY-20
- Reduced drilling costs by 14% in 1H-21 versus FY-20 average
- Company-owned sand mine protects against sand cost inflation, saving an estimated $200,000 per well
- Commitment to reduce GHG emissions by 20% and eliminate routine flaring by 2025

[1]See Appendix for reconciliations and definitions of non-GAAP measures

Oily, High-Margin Inventory Built Through Acquisition Strategy

	W. Glasscock County	Howard County	Total
Net acres	~4,350	~33,150	~37,500
Target formations	LS/WC-A/WC-B	LS/WC-A	*
Locations (gross)[1]	~40	~225	~265





[1]Gross operated locations as of January 2021 (adjusted for 2020 completions), pro forma for acquisition closed 7/1/2021;
[2]Production data normalized to 10,000' lateral length, downtime days excluded
Map and acreage as of 7-8-21

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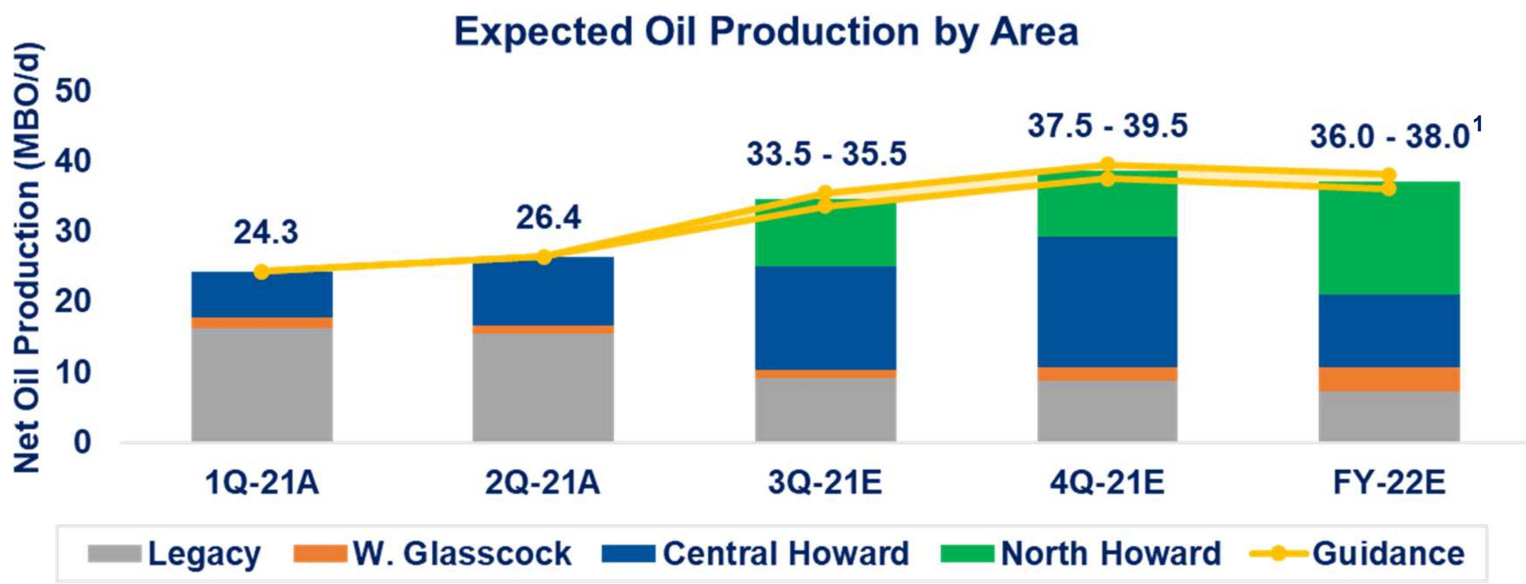
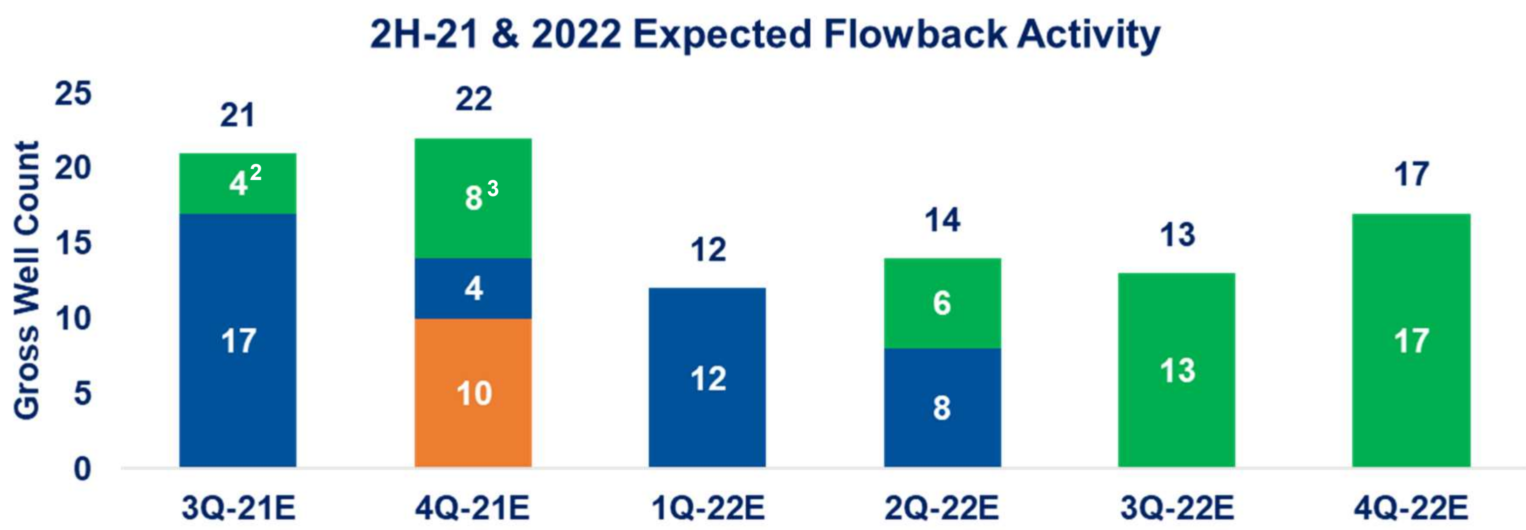
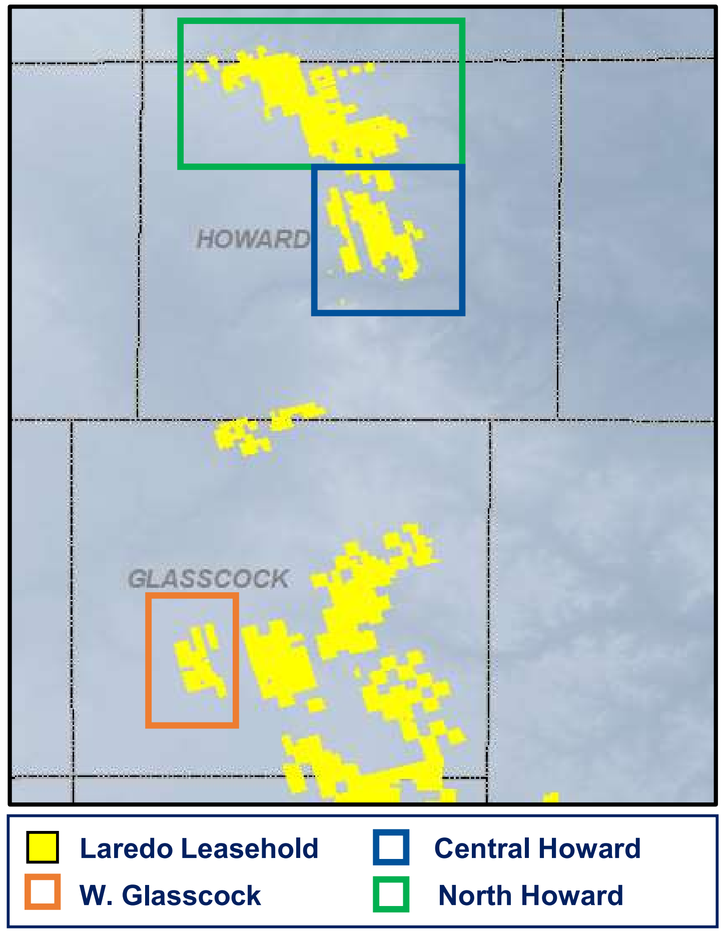
Development Focused on Acquired Leasehold







	FY-21E Guidance	FY-22E Preliminary[1]
Spuds	64	60
Completions	67	60
Working Interest	100%	96%
Lateral Length	10,000'	11,500'
Production, MBOE/d	77.0 - 80.0	75.0 - 78.0
Oil Production, MBO/d	30.5 - 31.5	36.0 - 38.0

[1]2022 oil production based on expected development plan of 2 rigs and 1 frac crew;
[2]Wells completed by Sabalo prior to closing of transaction on 7-1-21;
[2]Five wells were spud by Sabalo prior to closing of transactions on 7-1-21

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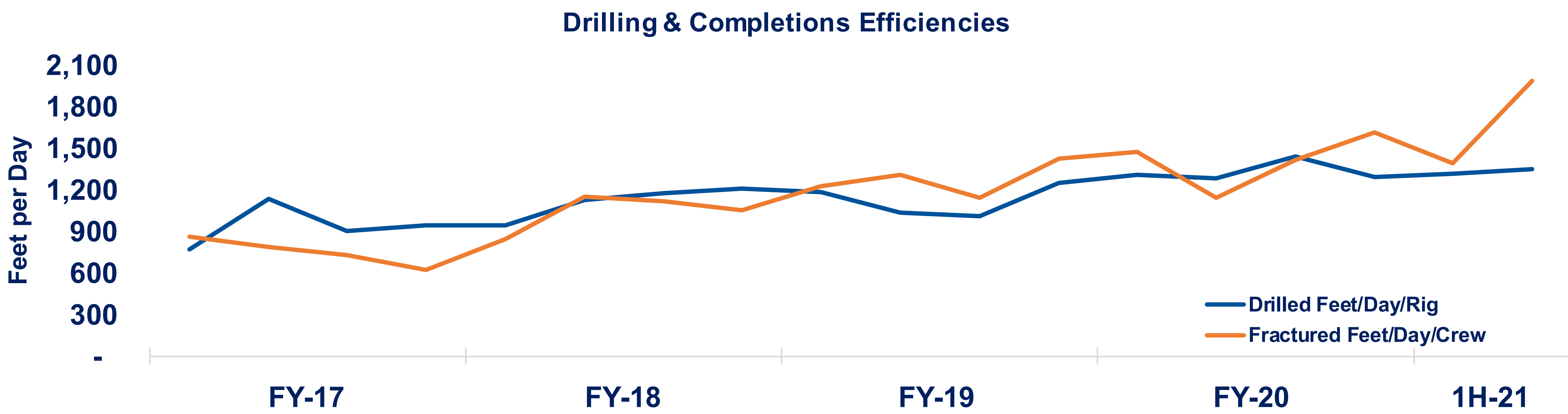
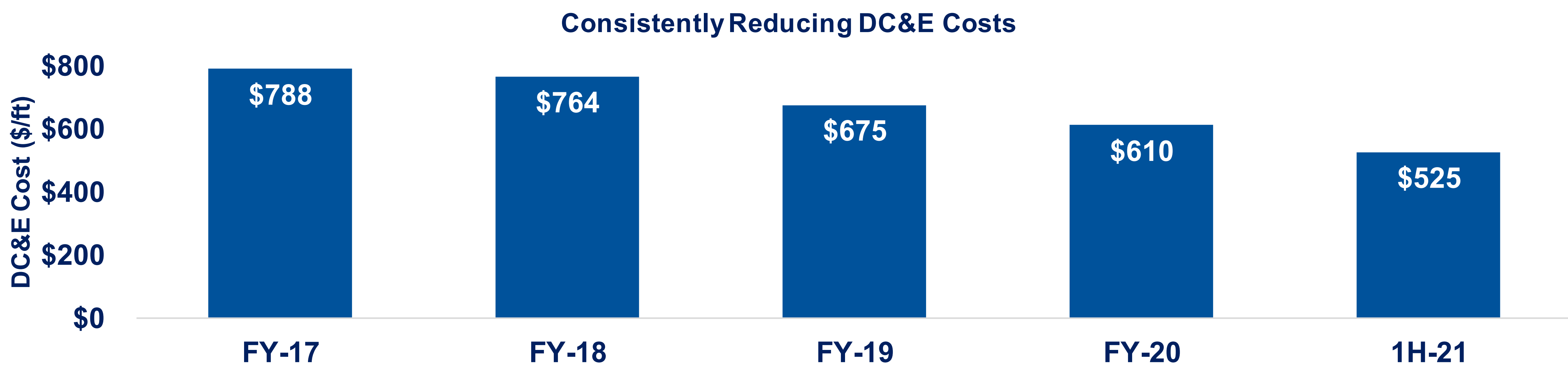
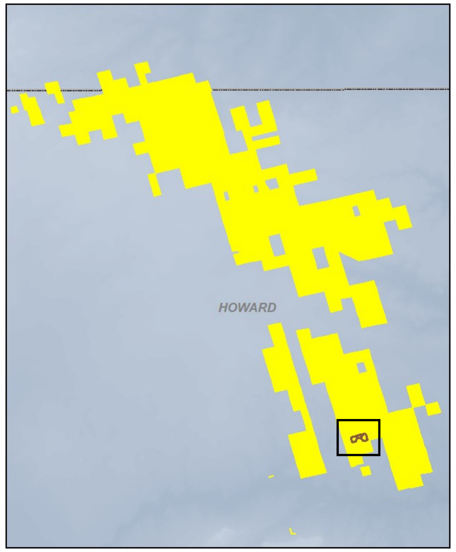
Maintaining Operational & Cost Advantages





Laredo-Owned Sand Mine Saves on Completions Costs



LPI Leasehold
Mining Area

Operated on Laredo-owned surface acreage

5+ years supply of sand

Protects against sand cost inflation

Reduces emissions

~$200,000[1] savings per well versus market price

- Utilized in all 2Q-21 completions, 98% of all sand used
- Mine operated by a third party
- No additional capital investment beyond surface acreage acquisition
- Elimination of 300,000 miles per month of truck traffic and utilization of wet sand reduces emissions

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[1]For Howard County completions

Operations Focused on Reducing Emissions

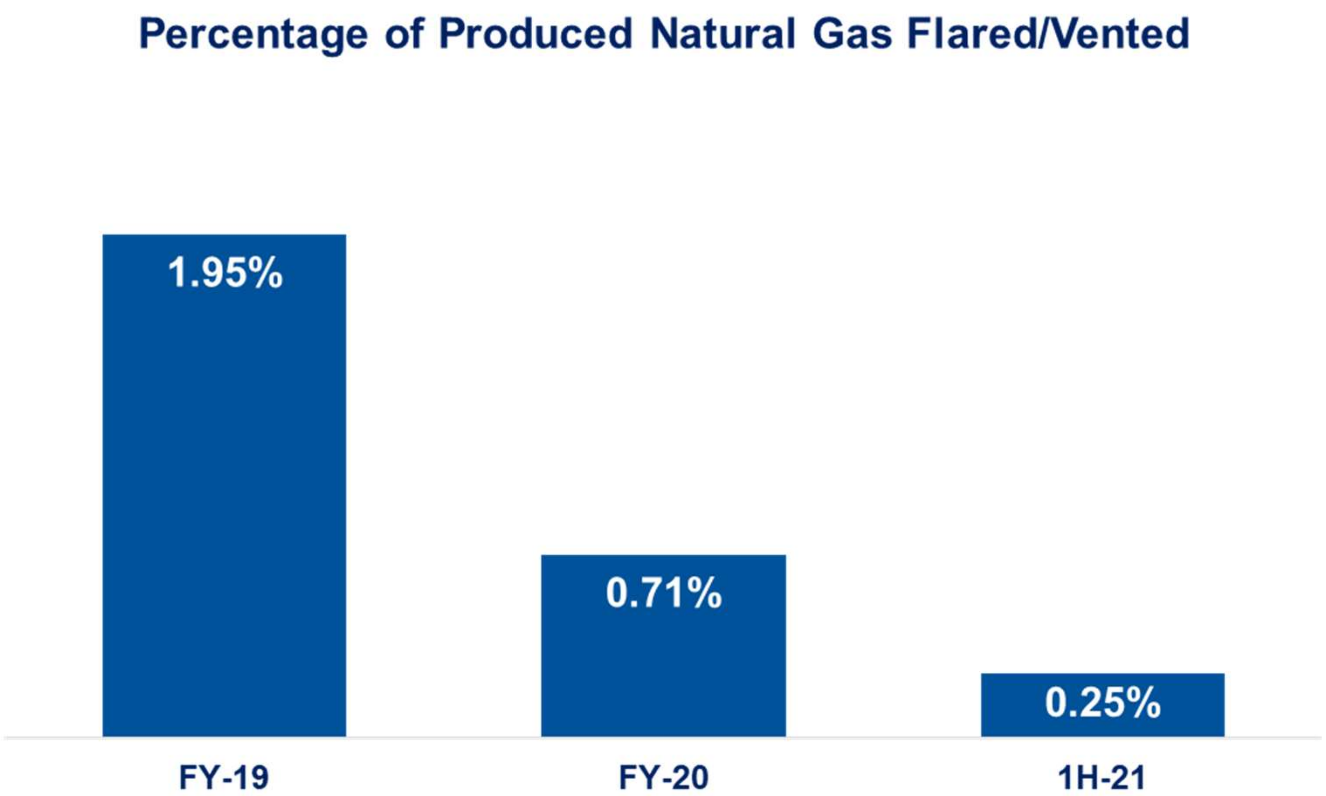
For the second consecutive year, flaring/venting reduction targets are part of executive compensation metrics

Emissions Reduction Targets for 2025

20% reduction in GHG intensity[1]

Zero routine flaring

<0.20% methane emissions[1,2]

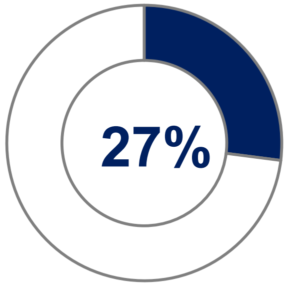


[1]2019 calendar year as baseline; [2]As a percentage of natural gas production

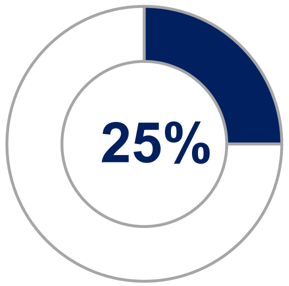
Corporate and Community Responsibility

Diversity[1]

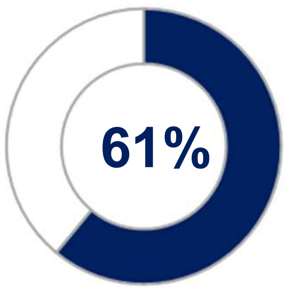
Women in workforce



Minorities in workforce



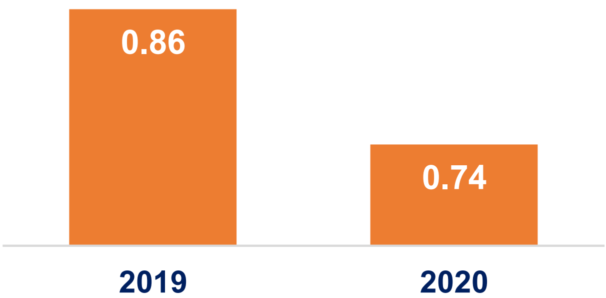
Women and/or minorities in professional-or-higher roles



Laredo intends to disclose EEO-1 data by YE-21

Safety

TRIR[2]



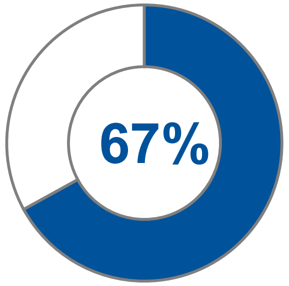
Laredo had zero at-fault vehicle incidents in 2020

Giving

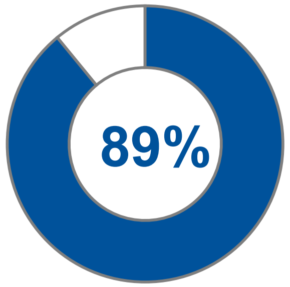
>$610,000

Total amount donated since 2019 to improve our local communities

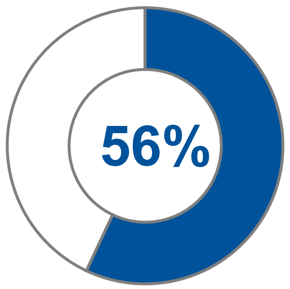
Governance



Board refresh in last 2 years



Independent Directors



Female & Minority Directors

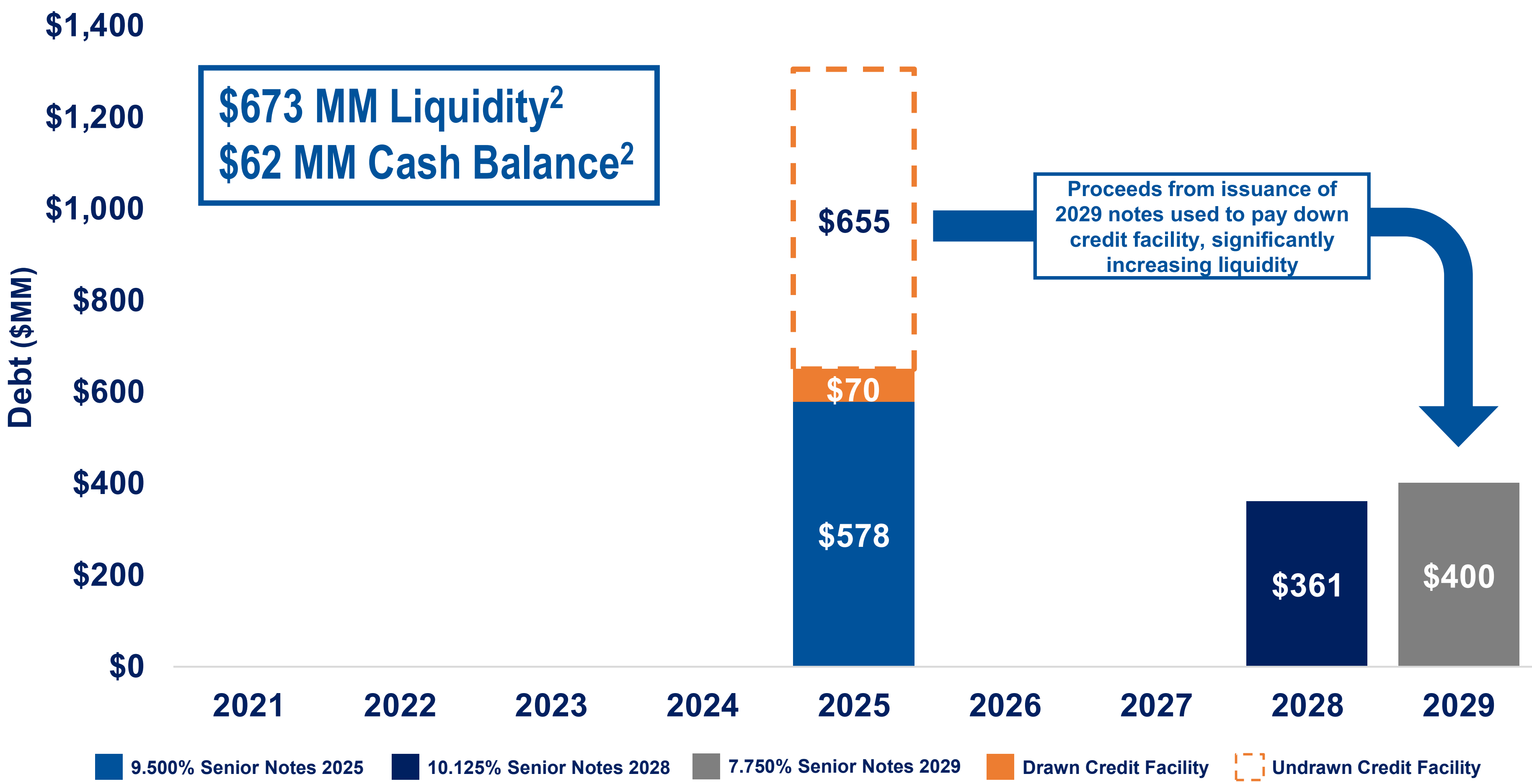
Separated roles of Chairman and CEO October 2019

[1]Data as of 12-31-20; [2]Combined employee and contractor Total Recordable Incident Rate

Actively Managing our Balance Sheet & Liquidity

- No term-debt maturities until 2025
- Executed "At-the-Market" equity program YTD 2021 resulting in ~$73 million of net proceeds
- Extended credit facility maturity until 2025
- Active hedge program to protect Free Cash Flow[1]
- Program expected to generate sustainable Free Cash Flow[1] used to reduce debt and drive leverage down to 1.5x by YE-22

Current Maturity Profile



Moody's upgrades Laredo's senior unsecured notes to B3 from Caa1[3]

[1]See Appendix for reconciliations and definitions of non-GAAP measures; [2]Balance as of 8-4-21; [3]As of 7-12-21

Active Hedge Program to Protect Free Cash Flow

Crude Oil Hedge Book

(Volume in MBbl; Price in $/Bbl)	3Q-21	4Q-21	FY-22
Brent Swaps	1,891	1,891	4,125
WTD Price	$51.29	$51.29	$48.34
Brent Collars	331	331	1,551
WTD Floor Price	$55.00	$55.00	$56.65
WTD Ceiling Price	$66.53	$66.53	$65.44
WTI Swaps	244	368	365
WTD Price	$69.46	$69.46	$64.40
WTI Collars	61	92	3,395
WTD Floor Price	$63.00	$63.00	$58.23
WTD Ceiling Price	$67.65	$67.65	$69.39
Total Brent Swaps/Collars	2,527	2,682	9,435
WTD Floor Price	$53.81	$54.64	$53.88

Natural Gas Liquids Hedge Book

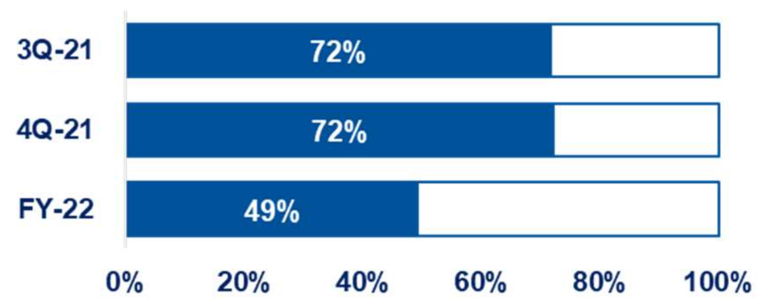
(Volume in MBbl; Price in $/Bbl)	3Q-21	4Q-21	FY-22
Ethane Swaps	230	230	1,533
WTD Price	$12.01	$12.01	$11.42
Propane Swaps	611	611	1,168
WTD Price	$22.90	$22.90	$35.91
Butane Swaps	204	204	365
WTD Price	$25.87	$25.87	$41.58
Isobutane Swaps	56	56	110
WTD Price	$26.55	$26.55	$42.00
Pentane Swaps	222	222	365
WTD Price	$38.16	$38.16	$60.65

Natural Gas Hedge Book

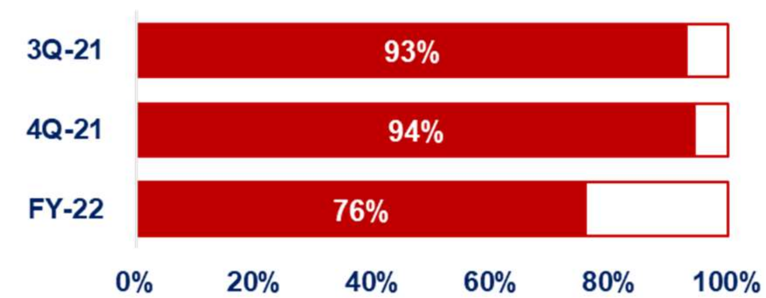
(Volume in MMBtu; Price in $/MMBtu)	3Q-21	4Q-21	FY-22
Henry Hub Swaps	10,718,000	10,718,000	3,650,000
WTD Price	$2.59	$2.59	$2.73
Henry Hub Collars	0	0	29,200,000
WTD Floor Price	$0.00	$0.00	$3.09
WTD Ceiling Price	$0.00	$0.00	$3.84
Total Henry Hub Swaps/Collars	10,718,000	10,718,000	32,850,000
WTD Floor Price	$2.59	$2.59	$3.05
Waha Basis Swaps	14,278,400	14,278,400	29,017,500
WTD Price	($0.47)	($0.47)	($0.36)

Crude Oil Production Hedged[1]

Natural Gas Liquids Production Hedged[1]



Natural Gas Production Hedged[1]



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[1]Hedge percentage calculated off mid-point guidance
Note: NGL barrel composition includes 42% Ethane, 33% Propane, 11% Butane, 3% Isobutane and 11% Pentane

Guidance

Production:	3Q-21	4Q-21	FY-21
Total production (MBOE/d)	74.5 - 77.5	77.5 - 80.5	77.0 - 80.0
Oil production (MBO/d)	33.5 - 35.5	37.5 - 39.5	30.5 - 31.5
Incurred capital expenditures[1] ($ MM)	$150	$105	$420

Average sales price realizations: *(excluding derivatives)*	3Q-21
Oil (% of WTI)	99%
NGL (% of WTI)	35%
Natural gas (% of Henry Hub)	75%

Net settlements received (paid) for matured commodity derivatives ($ MM):	3Q-21
Oil	($48)
NGL	($29)
Natural Gas	($17)

Other ($ MM):	3Q-21
Net income / (expense) of purchased oil	($6.8)

Operating costs & expenses ($/BOE):	3Q-21
Lease operating expenses	$3.90
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	6.50%
Transportation and marketing expenses	$1.60
General and administrative expenses (excluding LTIP)	$1.65
General and administrative expenses (LTIP cash)	($0.20)
General and administrative expenses (LTIP non-cash)	$0.25
Depletion, depreciation and amortization	$8.00

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[1]Excludes non-budgeted acquisitions and leasehold expenses

APPENDIX

Recent Acquisition/Divestiture Drives Significantly Higher Oil Cut

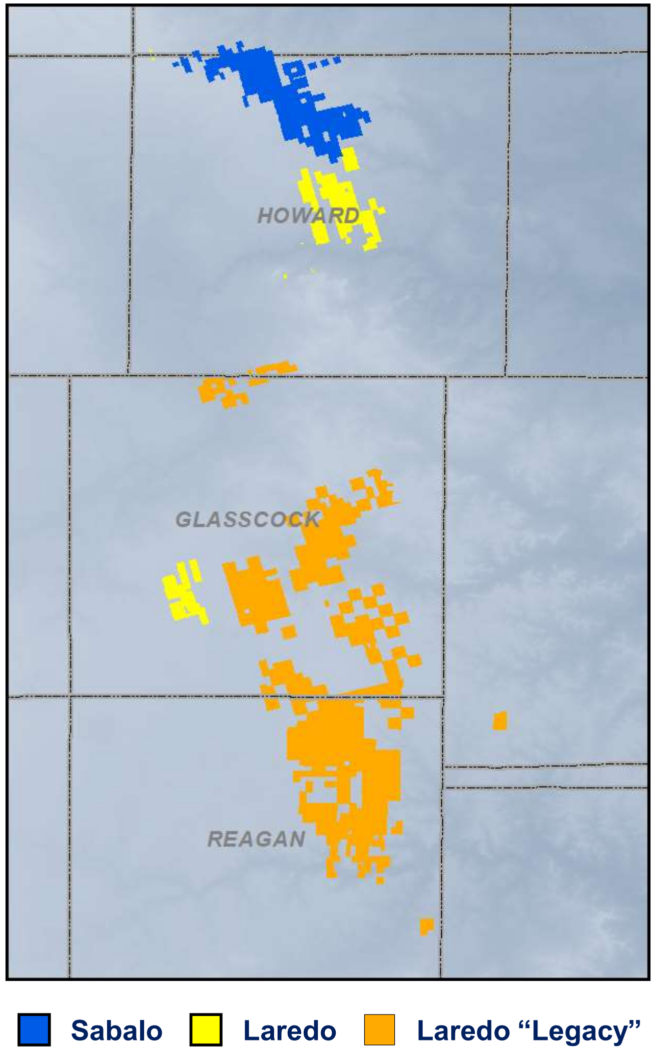
Acquisition Overview

- Establishes core position in Howard County of >33,000 net acres
- Contiguous acreage position directly adjacent to existing position enables efficient operations
- Majority of midstream infrastructure in place and all agreements are acreage dedications with no MVC's
- Extends development runway of high-margin, oil-weighted locations at conservative spacing assumptions of 12 wells per DSU (LS/WC-A)
- Purchase price of $715mm funded by:
  - $405mm "Legacy" PDP sale | $201mm RBL draw[1] | ~2.5mm common shares to sellers

Divestiture Overview

- Sale of 37.5% of Laredo's gross working interest in operated PDP reserves to an affiliate of Sixth Street Partners LLC
- Initial proceeds of $405 million plus potential cash-flow based earn-out payments over six years
- Transaction solely within Laredo's "Legacy" acreage footprint, wellbore only, no undeveloped locations

	Acquisition	Divestiture
Net Acres	~21,000	*
Gross Op Locations / Avg. WI	~120 / 91% WI	*
Gross Non-Op Locations / Avg. WI	~150 / 12% WI	*
Average Lateral Length	10,000'	*
Current Net Production (three stream)	~13,600 BOE/d (89% oil)	~25,000 BOE/d (23% oil)
PDP Reserves (three stream)	~30 million BOE (73% oil)	~94 million BOE (18% oil)

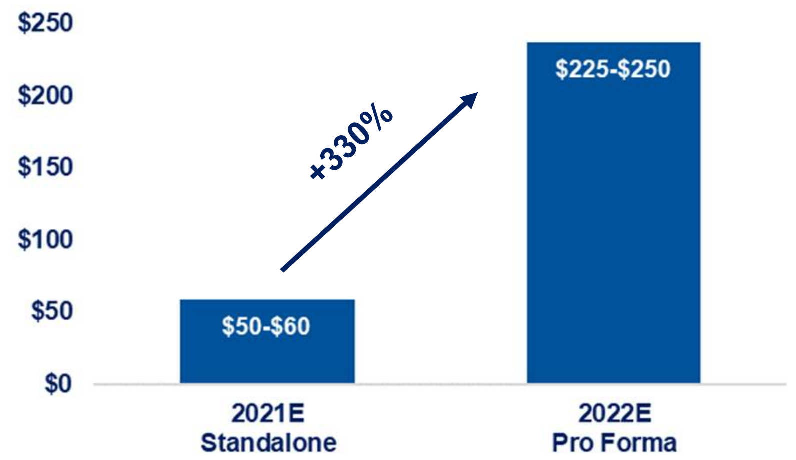


[1]Net of customary closing cost adjustments

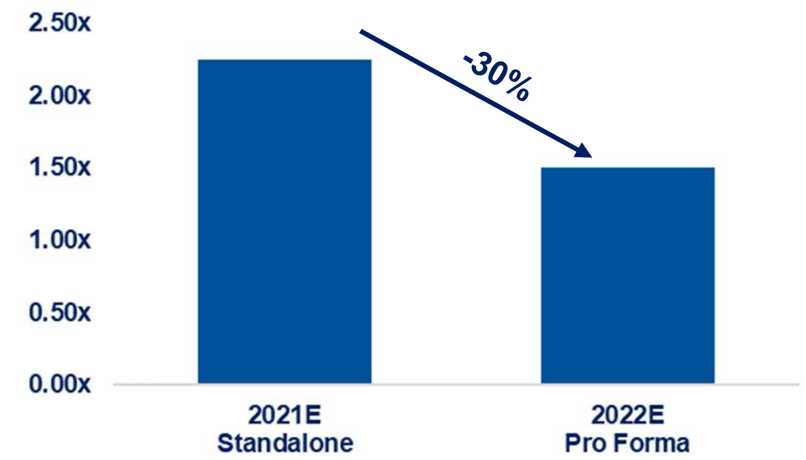
Transactions Improve Company Fundamentals

- Expected cumulative Free Cash Flow[1] of >$700mm by end of FY-25
- Anticipate leverage[1,2] approaching 1.0x by end of FY-25
- Expected ~80% increase in oil-weighted, high-margin inventory
- Oil cut expected to rise to ~50% by end of FY-22
- Expected to be accretive to long-term Free Cash Flow[1] and Adjusted EBITDA[1]

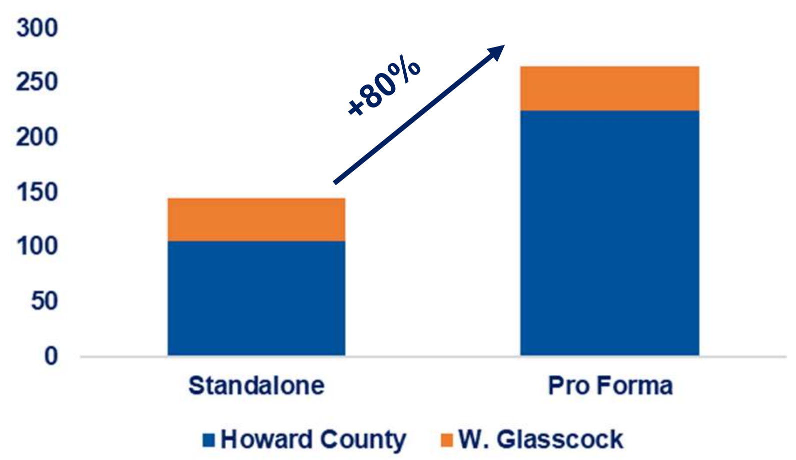
Free Cash Flow[1] ($mm)



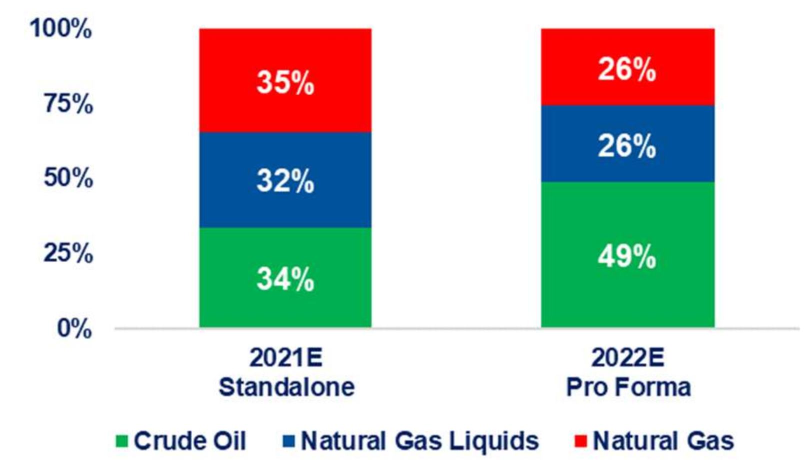
Leverage Net Debt to EBITDAX[1,2]



Gross Operated Locations

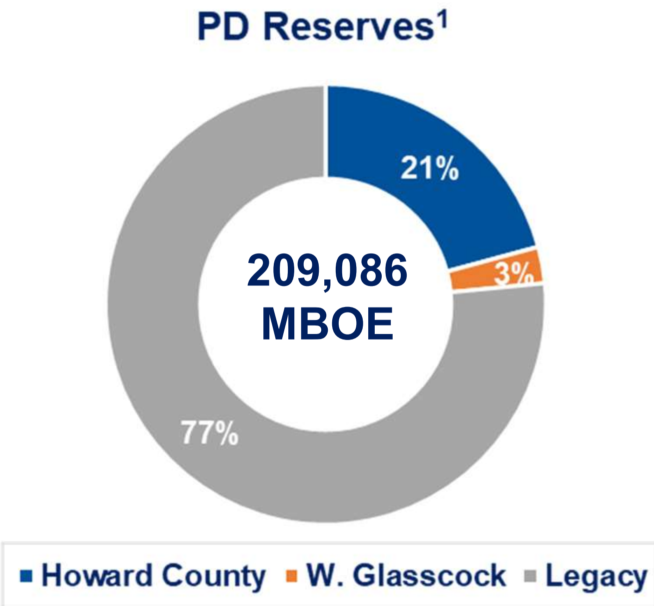


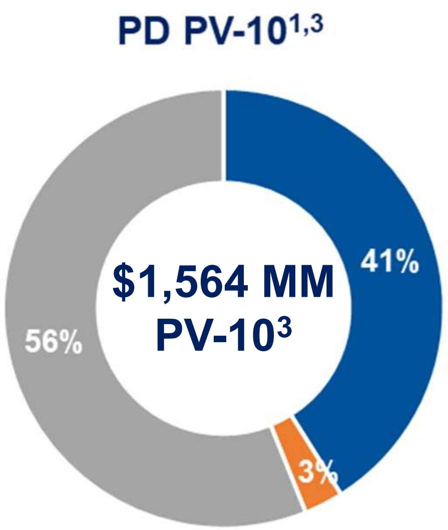
Production Mix

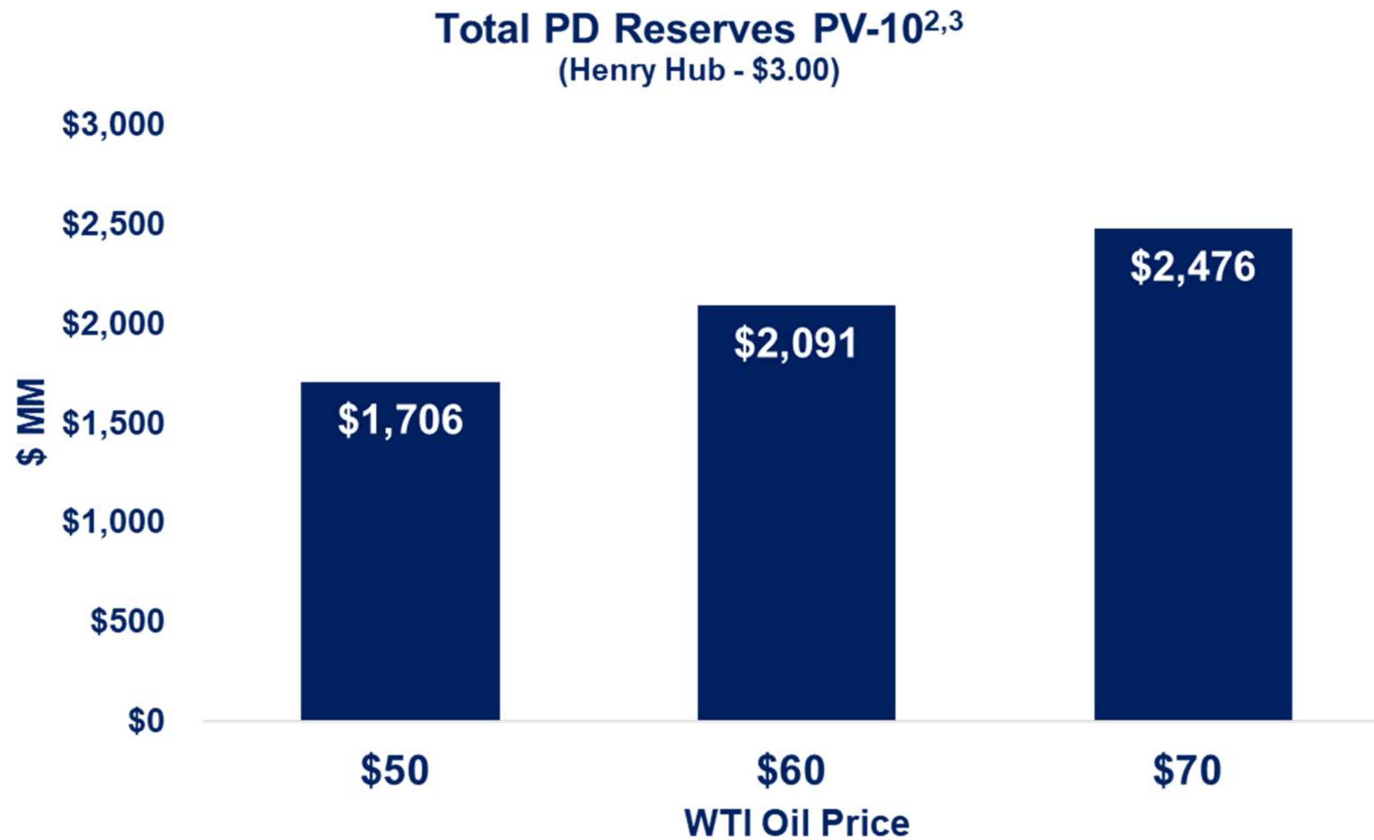


[1]See Appendix for definitions of non-GAAP financial measures; [2]Net Debt/TTM Consolidated EBITDAX
Note: All projections assume current commodity prices

Howard County Driving Reserves Value







Howard County proved developed reserves are 69% oil, significantly increasing Laredo's exposure to higher oil prices

[1]Based only on wells categorized as Proved Developed as of July 1, 2021 at the following SEC benchmark pricing: Oil $46.26/bbl, Natural Gas $2.07/mcf, Natural Gas Liquids $23.68/bbl;
[2]Based only on wells categorized as Proved Developed as of July 1, 2021 and normalized to $3.00 Henry Hub gas price
[3]See Appendix for definitions of non-GAAP measures

Commodity Prices Used for 3Q-21 Average Sales Price Realization and Derivatives Guidance

Oil:

	WTI NYMEX ($/Bbl)	Brent ICE ($/Bbl)
Jul-21	$72.43	$74.25
Aug-21	$73.72	$75.37
Sep-21	$72.96	$74.55
3Q-21 Average	$73.04	$74.73

Natural Gas:

	HH ($/MMBtu)	Waha ($/MMBtu)
Jul-21	$3.62	$3.36
Aug-21	$4.04	$3.87
Sep-21	$3.91	$3.68
3Q-21 Average	$3.86	$3.64

Natural Gas Liquids:

	C2 ($/Bbl)	C3 ($/Bbl)	IC4 ($/Bbl)	NC4 ($/Bbl)	C5+ ($/Bbl)	Composite ($/Bbl)
Jul-21	$13.15	$45.74	$53.11	$52.68	$67.33	$35.41
Aug-21	$13.55	$47.36	$55.55	$55.39	$69.83	$36.76
Sep-21	$13.65	$47.62	$55.70	$55.49	$69.93	$36.91
3Q-21 Average	$13.45	$46.90	$54.79	$54.52	$69.03	$36.36

Note: Pricing assumptions as of 7-30-21

Supplemental Non-GAAP Financial Measures

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss (GAAP) plus adjustments for share-settled equity-based compensation, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid for commodity derivatives that matured during the period, accretion expense, gains or losses on disposal of assets, 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 future 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,			
(in thousands, unaudited)	9/30/2020	12/31/2020	3/31/2021	6/30/2021
Net loss	($237,432)	($165,932)	($75,439)	($132,661)
Plus:				
Share-settled equity-based compensation, net	2,041	2,106	2,068	1,730
Depletion, depreciation and amortization	47,015	42,210	38,109	39,976
Impairment expense	196,088	109,804	—	1,613
Organizational restructuring expenses	—	—	—	9,800
Transaction expenses	—	—	—	1,741
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	45,250	81,935	154,365	216,942
Settlements received (paid) for matured derivatives, net	51,840	41,786	(41,174)	(57,607)
Settlements received for early-terminated commodity derivatives, net	6,340	—	—	—
Net premiums paid for commodity derivatives that matured during the period[(1)]	—	—	(11,005)	(10,183)
Accretion expense	1,102	1,105	1,143	1,158
(Gain) loss on disposal of assets, net	607	(94)	72	(66)
Interest expense	26,828	26,139	25,946	25,870
Gain on extinguishment of debt, net	—	(22,309)	—	—
Income tax (benefit) expense	(2,398)	3,208	(762)	(1,322)
Adjusted EBITDA	$137,281	$119,958	$93,323	$96,991

(1) Reflects net premiums paid previously or upon settlement that are attributable to derivatives settled in the respective periods presented

LAREDO PETROLEUM

Supplemental Non-GAAP Financial Measures

Consolidated EBITDAX (Credit Agreement Calculation)

"Consolidated EBITDAX" means, for any Person for any period, the Consolidated Net Income of such Person for such period, plus each of the following, to the extent deducted in determining Consolidated Net Income without duplication, determined for such Person and its Consolidated Subsidiaries on a consolidated basis for such period: any provision for (or less any benefit from) income or franchise Taxes; interest expense (as determined under GAAP as in effect as of December 31, 2016), depreciation, depletion and amortization expense; exploration expenses; and other non-cash charges to the extent not already included in the foregoing clauses (ii), (iii) or (iv), plus the aggregate Specified EBITDAX Adjustments during such period; *provided* that the aggregate Specified EBITDAX Adjustments shall not exceed fifteen percent (15%) of the Consolidated EBITDAX for such period prior to giving effect to any Specified EBITDAX Adjustments for such period, and minus all non-cash income to the extent included in determining Consolidated Net Income. For the purposes of calculating Consolidated EBITDAX for any Rolling Period in connection with any determination of the financial ratio contained in Section 10.1(b), if during such Rolling Period, Borrower or any Consolidated Restricted Subsidiary shall have made a Material Disposition or Material Acquisition, the Consolidated EBITDAX for such Rolling Period shall be calculated after giving pro forma effect thereto as if such Material Disposition or Material Acquisition, as applicable, occurred on the first day of such Rolling Period.

For additional information, please see the Company's Fifth Amended and Restated Credit Agreement, as amended, dated May 2, 2017 as filed with Securities and Exchange Commission.

The following table presents a reconciliation of net loss (GAAP) to Consolidated EBITDAX (Credit Agreement Calculation; non-GAAP):

	Three months ended,			
(in thousands, unaudited)	9/30/2020	12/31/2020	3/31/2021	6/30/2021
Net loss	($237,432)	($165,932)	($75,439)	($132,661)
Organizational restructuring expenses	—	—	—	9,800
Gain on extinguishment of debt, net	—	(22,309)	—	—
(Gain) loss on disposal of assets, net	607	(94)	72	(66)
Consolidated Net Loss	(236,825)	(188,335)	(75,367)	(122,927)
Mark-to-market on derivatives:				
Loss on derivatives, net	45,250	81,935	154,365	216,942
Settlements received (paid) for matured derivatives, net	51,840	41,786	(41,174)	(57,607)
Settlements received for early-terminated commodity derivatives, net	6,340	—	—	—
Mark-to-market loss on derivatives, net	103,430	123,721	113,191	159,335
Premiums received for commodity derivatives	—	—	9,041	—
Non-Cash Charges/Income:				
Deferred income tax (benefit) expense	(2,398)	3,208	(762)	(1,322)
Depletion, depreciation and amortization	47,015	42,210	38,109	39,976
Share-settled equity-based compensation, net	2,041	2,106	2,068	1,730
Accretion expense	1,102	1,105	1,143	1,158
Impairment expense	196,088	109,804	—	1,613
Interest Expense	26,828	26,139	25,946	25,870
Consolidated EBITDAX *after EBITDAX Adjustments (limited to 15%) (non-GAAP)*	$137,281	$119,958	$113,369	$105,433

LAREDO PETROLEUM

Supplemental Non-GAAP Financial Measures

Net Debt

Net Debt, a non-GAAP financial measure, is calculated as the face value of long-term debt less cash and cash equivalents. Management believes Net Debt is useful to management and investors in determining the Company's leverage position since the Company has the ability, and may decide, to use a portion of its cash and cash equivalents to reduce debt. Net Debt as of 6-30-21 was $1.125 B.

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 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.

Net Debt to TTM Consolidated EBITDAX (Credit Agreement Calculation)

Net Debt to TTM Consolidated EBITDAX is calculated as Net Debt divided by trailing twelve-month Consolidated EBITDAX. Net Debt to Consolidated EBITDAX is used by the banks in our Senior Secured Credit Agreement as a measure of indebtedness and as a calculation to measure compliance with the Company's leverage covenant.

Cash Flow

Cash flow, a non-GAAP financial measure, represents cash flows from operating activities before changes in operating assets and liabilities, net.

Free Cash Flow

Free Cash Flow is a non-GAAP financial measure, that we define as net cash provided by operating activities (GAAP) before changes in operating assets and liabilities, net, less incurred capital expenditures, excluding non-budgeted acquisition costs. Free Cash Flow 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, 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.

We are unable to provide a reconciliation of the forward-looking Free Cash Flow projection contained in this presentation to net cash provided by operating activities, the most directly comparable GAAP financial measure, because we cannot reliably predict certain of the necessary components of net cash provided by operating activities, such as changes in working capital, without unreasonable efforts. Such unavailable reconciling information may be significant.

Supplemental Non-GAAP Financial Measures

PV-10

PV-10, a non-GAAP financial measure, is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. Management believes that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to the Company's estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of the Company's proved oil, NGL and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of proved reserves to other companies. The Company uses this measure when assessing the potential return on investment related to proved oil, NGL and natural gas assets. However, PV-10 is not a substitute for the standardized measure of discounted future net cash flows. The PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of the Company's oil, NGL and natural gas reserves of the property.

We are unable to provide a reconciliation of the forward-looking PV-10 projection contained in this presentation to the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because we cannot reliably predict certain of the necessary components of the standardized measure of discounted future net cash flows, such as reserve additions, extensions, price and performance revisions, and taxes outside of the normal year-end reserve evaluation process without unreasonable efforts. Such unavailable reconciling information may be significant.